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HEARING EXHIBITS FOR THE HEARING HELD on November 5, 2012, in Docket No. 120007-EI

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
STAFF – EXHIBITS				
**** Staff's composite exhibits include the redacted versions of confidential documents.***				
1		Exhibit List	Comprehensive Exhibit List	
2		Staff's Composite Exhibit	***Florida Power & Light*** ***Interrogatories*** 1. FPL Response to Staff's 1st Set of Interrogatories (Nos. 1-8) *[Bates Nos. 00001-00033]* 2. FPL Response to Staff's Amended 2nd Set of Interrogatories (Nos. 9-21) *[Bates Nos. 00034-00062]* 3. FPL's Response to Staff's 3rd Set of Interrogatories (Nos. 22-37) *[Bates Nos. 00063-00107]* 4. FPL's Response to Staff's 4th Set of Interrogatories (Nos. 38-48) *[Bates Nos. 00108-00129]* 5. FPL's Response to Staff's 5th Set of Interrogatories (Nos. 49-52) *[Bates Nos. 00130-00147]* 6. FPL's Response to Staff's 6th Set of Interrogatories (No. 53-56) *[Bates Nos. 00148-00162]* 7. FPL's Response to Staff's 7th Set of Interrogatories (Nos. 57-58) *[Bates Nos. 00163-00175]* 8. FPL's Response to Staff's 8th	**stipulated**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 1
PARTY Commission Staff
DESCRIPTION Comprehensive Exhibit List

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

			Set of Interrogatories (Nos. 59-62) *[Bates Nos. 00176-00186]* ***Production of Documents*** 9. FPL's Response to Staff's 1st Production of Documents (No. 1) *[Bates Nos. 00187-00188]* 10. FPL's Response to Staff's 2nd Production of Documents (No. 2) *[Bates Nos. 00189-00210]* ***Progress Energy Florida*** ***Interrogatories*** 11. PEF's Response to Staff's 1st Set of Interrogatories (Nos. 1-5) *[Bates Nos. 00211-00223]* 12. PEF's Response to Staff's 2nd Set of Interrogatories (Nos. 6-16) *[Bates Nos. 00224-00231]* 13. PEF's Response to Staff's 3rd Set of Interrogatories (Nos. 17-19) *[Bates Nos. 00232-00239]* ***Production of Documents*** 14. PEF's Response to Staff's 1st Production of Documents (No. 1) *[Bates Nos. 00240-00246]* ***Tampa Electric Company*** ***Interrogatories*** 15. TECO's Response to Staff's 1st Set of Interrogatories (Nos. 1-5) *[Bates Nos. 00247-00257]* 16. TECO's Response to Staff's 2nd Set of Interrogatories (Nos. 6-12) *[Bates Nos. 00258-00269]*	

			17. TECO's Response to Staff's 3rd Set of Interrogatories (Nos. 13-15) *[Bates Nos. 00270-00279]* ***Gulf Power Company*** ***Interrogatories*** 18. Gulf's Response to Staff's 1st Set of Interrogatories (Nos. 1-2) *[Bates Nos. 00280-00286]* 19. Gulf's Response to Staff's 2nd Set of Interrogatories (Nos. 3-6) *[Bates Nos. 00287-00295]* 20. Gulf's Response to Staff's 3rd Set of Interrogatories (Nos. 7-9) *[Bates Nos. 00296-00302]* 21. Gulf's Response to Staff's 4th Set of Interrogatories (No. 10) *[Bates Nos. 00303-00306]* 22. Gulf's Response to Staff's 5th Set of Interrogatories (Nos. 11-13) *[Bates Nos. 00307-00312]* ***Additional Materials*** 23. Gulf Power Company Environmental Compliance Program Update *[Bates Nos. 00313-00339]*	
FLORIDA POWER & LIGHT COMPANY (FPL) - (DIRECT)				
3	R. R. LaBauve	RRL-1	Port Everglades Manatee Heating System Conceptual Location of heated refuge, heater and pump systems	**stipulated**

4	R. R. LaBauve	RRL-2	Florida Department of Environmental Protection Administrative ("FDEP") Industrial Wastewater Facility Permit Number FL0001538 for PPEE	**stipulated**
5	R. R. LaBauve	RRL-3	PPE Manatee Protection Plan ("MPP")	**stipulated**
6	R. R. LaBauve	RRL-4	U.S. Fish and Wildlife Service ("FWS") letter to FPL regarding manatee protection at PPE	**stipulated**
7	T. J. Keith	TJK-1	Appendix I Environmental Cost Recovery Final True-up January 2011-December 2011 Commission Forms 42 - 1A through 42 - 9A	**stipulated**
8	R. R. LaBauve	RRL-5A	FPL Supplemental CAIR/CAMR/CAVR Filing	**stipulated**
9	T. J. Keith	TJK-2	Appendix I Environmental Cost Recovery – Actual/Estimated Period January 2012-December 2012 Commission Forms 42-1E through 42-9E	**stipulated**
10	R. R. LaBauve	RRL-5B	Relevant excerpt from the Cape Canaveral Plant (PCC) State IWW Permit	**stipulated**
11	R. R. LaBauve	RRL-6	Relevant excerpt from the Riviera Plant (PRV) NPDES Permit	**stipulated**
12	R. R. LaBauve	RRL-7	New Gopher Tortoise Guidelines	**stipulated**
13	R. R. LaBauve	RRL-8	Relevant excerpt from the St. Lucie Plant (PSL) NPDES Permit	**stipulated**
14	T. J. Keith	TJK-3	Appendix I Environmental Cost Recovery Projections January 2013-December 2013 - Commission Forms 42-1P through 42-8P	**stipulated**

15	R. R. LaBauve	RRL-9	Chapter 62-302, Florida Administrative Code, Surface Water Quality Standards (FDEP Proposed)	**stipulated**
16	R. R. LaBauve	RRL-10	Title 40 Code of Federal Regulations Part 131, Water Quality Standards for the State of Florida's Lakes and Flowing Waters (EPA)	**stipulated**
PROGRESS ENERGY FLORIDA, INC. (PEF) - (DIRECT)				
17	Patricia Q. West	PQW-1	Review of Integrated Clean Air Compliance Plan	**stipulated**
18	Patricia Q. West	PQW-2	Letter re: Progress Energy Florida's NPDES Renewal Program and associated Administrative Order Filed on February 8, 2012	**stipulated**
19	Patricia Q. West	PQW-3	Verified Petition to Modify Scope of Existing Environmental Program that PEF filed on March 20, 2012	**stipulated**
20	Patricia Q. West	PQW-4	Letter re: Progress Energy Florida's Integrated Clean Air Compliance Plan filed on May 14, 2012	**stipulated**
21	Patricia Q West	TGF-3R	Form 42-5P, pages 3 of 20, 4 of 20, 5 of 20, 6 of 20, 7 of 20, 8 of 20, 9 of 20, 11 of 20, 12 of 20, 13 of 20, 14 of 20, 15 of 20, 16 of 20, 17 of 20, and 18 of 20, 10 of 20, and 20 of 20	**stipulated**
22	Jeff Swartz	JS-1	Crystal River Project Organizational Structure	**stipulated**
23	Jeff Swartz	TGF-3R	Form 42-5P page 7 of 20	**stipulated**
24	George Hixon	TGF-3R	Form 42-5P page 20 of 20	**stipulated**
25	Cory Zeigler	TGF-3R	Form 42-5P, Pages 1 of 20, 2 of 20, and 10 of 20	**stipulated**

26	Will Garrett	WG-1	PSC Forms 42-1A thru 42-8A - January 2011 – December 2011	**stipulated**
27	Will Garrett	WG-2	Capital Program Detail January 2011 – December 2011	**stipulated**
28	Thomas G. Foster	TGF-1	PSC Forms 42-1E through 42-9E January 2012 – December 2012	**stipulated**
29	Thomas G. Foster	TGF-2	Capital Program Detail January 2012 – December 2012	**stipulated**
30	Thomas G. Foster	TGF-3R	PSC Forms 42-1P through 42-8P January 2013 – December 2013	**stipulated**
31	Thomas G. Foster	TGF-4	Capital Program Detail January 2013 – December 2013	**stipulated**
TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)				
32	Howard T. Bryant	HTB-1	Final Environmental Cost Recovery Commission Forms 42-1A through 42-9A for the period January 2011 through December 2011	**stipulated**
33	Howard T. Bryant	HTB-2	Environmental Cost Recovery Commission Forms 42-1E through 42-9E for the Period January 2012 through December 2012	**stipulated**
34	Howard T. Bryant	HTB-3	Forms 42-1P through 42-8P Forms for January 2013 through December 2013	**stipulated**
GULF POWER COMPANY (GULF) - (DIRECT)				
35	R. W. Dodd	RWD-1	Calculation of Final True-up 1/11 – 12/11	**stipulated**
36	R. W. Dodd	RWD-2	Calculation of Estimated True-up 1/12 – 12/12	**stipulated**

37	R. W. Dodd	RWD-3 (revision to 8/28/12 testimony pages 6 & 7 and schedules 1P, 3P, 4P page 1, and 7P)	Calculation of Projection 1/13 - 12/13	**stipulated**

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FPL's Response to Staff's 1st Set of Interrogatories (Nos. 1-8)

FLORIDA PUBLIC SERVICE COMMISSION			
DOCKET NO.	120007-EI	EXHIBIT	2
PARTY	Staff's Composite Exhibits		
DESCRIPTION	Various Irrogs, PODs, Bates 00001- through Bates 00339		

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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MAR 2012
FLORIDA PUBLIC SERVICE COMMISSION
COMMISSION CLERK

IN RE: Environmental Cost Recovery Clause	Docket No: 120007-EI Date: March 23, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIRST SET OF INTERROGATORIES (NOS. 1-8)

Florida Power & Light Company ("FPL"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-12-0060-PCO-EO, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories (Nos. 1-8).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the documents, if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these responses provide all of the information that FPL obtained after a reasonable and diligent search

120007 Hearing Exhibits 00002

conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the Florida Public Service Commission in this docket. To require any non-regulated entities to

120007 Hearing Exhibits 00003

participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses.

Notwithstanding any of the foregoing general objections and without waiving these objections, FPL intends in good faith to respond to Staff's discovery requests.

II. Responses

Attached hereto are FPL's answers to Interrogatory Nos. 1 through 8 of Staff's First Set of Interrogatories consistent with its objections, together with the affidavits of the persons providing the answers.

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By: _____
Maria Jose Moncada
Fla. Bar No. 0773301

CERTIFICATE OF SERVICE
Docket No. 120007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by overnight delivery*, electronic mail and United States Mail on this 23rd day of March, 2012 to the following:

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120007 Hearing Exhibits 00006

Q.
Please complete the table below describing the avoided emissions and avoided fossil fuels usage for each of FPL's solar projects.

A.
Please see attached tables.

Florida Power & Light Company
Docket No. 120007-EI
Staff's 1st Set of Interrogatories
Question No. 1
Table 1, page 1 of 3

Next Generation DeSoto Solar Project

Year	Natural Gas Avoided by Solar Project MMBTU	Oil Avoided by Solar Project Barrels	CO2 emissions avoided by solar project tons	SO2 emissions avoided by solar project tons	NOx emissions avoided by solar project tons	NOx & SO2 emissions avoided by solar project tons
2011	402,000	5,400	35,188	44	64	108
2012	338,000	10,000	30,000	37	27	64
2013	342,000	5,000	27,000	19	13	32
2014	356,000	3,000	26,000	14	8	22
2015	360,000	3,000	25,000	12	6	18
2016	355,000	4,000	25,000	15	8	23
2017	350,000	5,000	25,000	16	7	23
2018	334,000	3,000	25,000	16	8	24
2019	313,000	4,000	27,000	17	10	27
2020	319,000	6,000	27,000	22	12	34
2021	326,000	5,000	25,000	16	10	26
2022	326,000	2,000	24,000	9	6	15
2023	318,000	1,000	24,000	8	5	13
2024	321,000	2,000	23,000	8	5	13
2025	325,000	2,000	23,000	11	7	18
2026	319,000	3,000	23,000	11	8	19
2027	309,000	3,000	24,000	13	9	22
2028	300,000	4,000	24,000	11	9	20
2029	290,000	2,000	25,000	10	7	17
2030	297,000	2,000	23,000	8	6	14
2031	294,000	3,000	22,000	10	6	16
2032	293,000	2,000	22,000	7	5	12
2033	281,000	1,000	22,000	7	5	12
2034	281,000	3,000	22,000	7	5	12
2035	278,000	2,000	21,000	7	5	12
2036	271,000	1,000	22,000	7	4	11
2037	277,000	1,000	21,000	5	4	9
2038	270,000	1,000	21,000	7	4	11
2039	274,000	1,000	19,000	5	3	8
2040	275,000	1,000	19,000	5	3	8

Note:

This table shows a projection of the emissions (CO2, SO2, and NOx) avoided as well as the fuel use (gas and oil) avoided by the 25 MW Solar PV facility. These values represent the difference in emissions and fuel use between two system simulations: one which represents the base case, and a second one that adds the 25 MW solar PV facility.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

FPL has not had a fully functional system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities until 2011. As a result, FPL does not have historical data available on avoided fuel and emissions prior to 2011. Projected avoided fuel and emissions starting January 2012 are included. These projected benefits were developed using FPL's production costing model PMAREA.

Next Generation Space Coast Solar Project

Year	Natural Gas Avoided by Solar Project MMBTU	Oil Avoided by Solar Project Barrels	CO2 emissions avoided by solar project tons	SO2 emissions avoided by solar project tons	NOx emissions avoided by solar project tons	NOx & SO2 emissions avoided by solar project tons
2011	147,000	1,900	12,819	16	23	39
2012	115,000	4,000	11,000	15	11	26
2013	116,000	2,000	9,000	7	6	13
2014	123,000	1,000	9,000	5	3	8
2015	124,000	2,000	9,000	4	3	7
2016	122,000	1,000	9,000	6	3	9
2017	118,000	2,000	9,000	7	3	10
2018	115,000	1,000	8,000	6	4	10
2019	107,000	1,000	9,000	7	4	11
2020	111,000	2,000	9,000	8	5	13
2021	112,000	3,000	8,000	7	4	11
2022	114,000	1,000	8,000	4	2	6
2023	112,000	0	8,000	3	2	5
2024	112,000	1,000	8,000	3	2	5
2025	113,000	1,000	8,000	4	3	7
2026	112,000	1,000	7,000	5	3	8
2027	109,000	1,000	8,000	5	4	9
2028	105,000	1,000	8,000	4	3	7
2029	103,000	1,000	8,000	4	3	7
2030	105,000	1,000	8,000	3	2	5
2031	103,000	1,000	8,000	4	2	6
2032	100,000	1,000	7,000	3	2	5
2033	97,000	0	8,000	2	2	4
2034	97,000	2,000	8,000	3	2	5
2035	96,000	1,000	7,000	3	2	5
2036	92,000	1,000	8,000	3	1	4
2037	95,000	1,000	7,000	2	2	4
2038	93,000	0	7,000	3	1	4
2039	94,000	0	6,000	2	1	3
2040	95,000	1,000	7,000	2	2	4

Note:

This table shows the emissions (CO2, SO2, and NOx) avoided as well as the fuel use (gas and oil) avoided by the 10 MW Solar PV facility. These values represent the difference in emissions and fuel use between two system simulations: one which represents the base case, and a second one that adds the 10 MW solar PV facility.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

FPL has not had a fully functional system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities until 2011. As a result, FPL does not have historical data available on avoided fuel and emissions prior to 2011. Projected avoided fuel and emissions starting January 2012 are included. These projected benefits were developed using FPL's production costing model PMAREA.

New Generation Martin Solar Project

Year	Natural Gas Avoided by Solar Project MMBTU	Oil Avoided by Solar Project Barrels	CO2 emissions avoided by solar project tons	SO2 emissions avoided by solar project tons	NOx emissions avoided by solar project tons	NOx & SO2 emissions avoided by solar project tons
2011	247,000	3,300	19,298	26	45	71
2012	761,000	24,000	70,000	93	71	164
2013	879,000	12,000	70,000	54	37	91
2014	922,000	9,000	65,000	40	22	62
2015	781,000	8,000	54,000	31	17	48
2016	931,000	10,000	65,000	42	21	63
2017	814,000	12,000	59,000	43	20	63
2018	894,000	11,000	67,000	44	24	68
2019	840,000	12,000	73,000	49	28	77
2020	821,000	17,000	69,000	61	33	94
2021	892,000	15,000	69,000	48	30	78
2022	836,000	6,000	61,000	27	17	44
2023	894,000	4,000	64,000	22	14	36
2024	861,000	5,000	60,000	24	14	38
2025	911,000	9,000	63,000	35	20	55
2026	907,000	10,000	63,000	33	23	56
2027	793,000	12,000	60,000	38	26	64
2028	866,000	12,000	68,000	36	27	63
2029	839,000	9,000	69,000	33	23	56
2030	862,000	6,000	66,000	27	20	47
2031	714,000	8,000	55,000	27	17	44
2032	854,000	7,000	65,000	24	18	42
2033	786,000	6,000	64,000	24	17	41
2034	835,000	6,000	65,000	23	16	39
2035	828,000	6,000	64,000	22	16	38
2036	721,000	4,000	59,000	22	14	36
2037	834,000	5,000	63,000	18	13	31
2038	762,000	4,000	59,000	20	13	33
2039	840,000	3,000	60,000	15	10	25
2040	848,000	4,000	59,000	14	10	24

Note:

This table shows the emissions (CO2, SO2, and NOx) avoided as well as the fuel use (gas and oil) avoided by the 75 MW Solar PV facility. These values represent the difference in emissions and fuel use between two system simulations: one which represents the base case, and a second one that adds the 75 MW solar PV facility.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

FPL has not had a fully functional system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities until 2011. As a result, FPL does not have historical data available on avoided fuel and emissions prior to 2011. Projected avoided fuel and emissions starting January 2012 are included. These projected benefits were developed using FPL's production costing model PMAREA.

Q.
Please complete the table below describing the CPVRR for each of FPL's solar projects.

A.
Please see attached tables.

New Generation DeSoto Solar Project
System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

	[1]	[2]	[3]	[4]	[5]
Year	Annual System Total Revenue Requirements with Solar Project $ Millions	Annual System Total Revenue Requirements without Solar Project $ Millions	Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	Differential in Customer Bill $/ 1000 kWH	Differential in Customer Bill $/ 1200 kWH
2008	0	0	0	0.000	0.000
2009	10	0	10	0.099	0.119
2010	16	0	16	0.155	0.186
2011	15	0	15	0.147	0.177
2012	2,910	2,894	16	0.159	0.190
2013	3,038	3,022	16	0.152	0.182
2014	3,371	3,357	15	0.140	0.168
2015	3,624	3,610	14	0.132	0.158
2016	4,445	4,432	13	0.116	0.139
2017	4,912	4,900	12	0.111	0.133
2018	6,521	6,510	11	0.100	0.120
2019	7,035	7,025	10	0.086	0.103
2020	7,859	7,848	10	0.088	0.106
2021	8,706	8,698	9	0.074	0.088
2022	9,149	9,140	8	0.068	0.081
2023	9,112	9,104	9	0.070	0.084
2024	9,701	9,694	7	0.057	0.069
2025	10,571	10,565	6	0.044	0.053
2026	11,187	11,181	6	0.046	0.056
2027	11,931	11,926	5	0.034	0.041
2028	12,520	12,515	5	0.037	0.044
2029	13,246	13,242	3	0.025	0.030
2030	14,162	14,158	4	0.029	0.035
2031	14,988	14,984	4	0.025	0.030
2032	16,240	16,237	3	0.020	0.024
2033	18,295	18,293	2	0.016	0.019
2034	19,671	19,670	1	0.006	0.007
2035	20,632	20,631	0	0.003	0.003
2036	22,856	22,857	0	-0.002	-0.003
2037	24,311	24,311	0	0.001	0.001
2038	25,525	25,526	0	-0.003	-0.004
2039	27,120	27,122	-2	-0.013	-0.015
2040	28,573	28,578	-4	-0.026	-0.032

Notes:

Negative indicates a reduction in the customer bill for the 25 MW solar project.

The annual revenue requirements include fixed costs (capital, fixed O&M and firm gas transportation costs) for future generation resources, as well as the three existing solar projects. Revenue requirements from existing facilities are not included as they would be the same for both simulations and would not impact the result. Projected variable costs (fuel, VOM, and emission costs) for all of FPL's generation resources, including existing ones are also included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

Next Generation Space Coast Solar Project
System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

Year	[1] Annual System Total Revenue Requirements with Solar Project $ Millions	[2] Annual System Total Revenue Requirements without Solar Project $ Millions	[3] Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	[4] Differential in Customer Bill $/ 1000 kWH	[5] Differential in Customer Bill $/ 1200 kWH
2008	0	0	0	0.000	0.000
2009	1	0	1	0.010	0.012
2010	7	0	7	0.068	0.082
2011	8	0	8	0.074	0.088
2012	2,901	2,894	7	0.073	0.088
2013	3,030	3,022	8	0.080	0.096
2014	3,364	3,357	8	0.074	0.089
2015	3,616	3,610	7	0.061	0.073
2016	4,438	4,432	6	0.058	0.069
2017	4,906	4,900	6	0.055	0.066
2018	6,515	6,510	5	0.042	0.050
2019	7,030	7,025	4	0.039	0.047
2020	7,854	7,848	5	0.045	0.054
2021	8,702	8,698	4	0.035	0.042
2022	9,144	9,140	4	0.031	0.037
2023	9,108	9,104	5	0.037	0.044
2024	9,698	9,694	4	0.034	0.041
2025	10,568	10,565	3	0.024	0.029
2026	11,185	11,181	4	0.029	0.035
2027	11,929	11,926	3	0.019	0.023
2028	12,519	12,515	3	0.024	0.029
2029	13,245	13,242	2	0.015	0.019
2030	14,161	14,158	3	0.021	0.025
2031	14,987	14,984	3	0.019	0.023
2032	16,238	16,237	1	0.010	0.012
2033	18,295	18,293	2	0.014	0.017
2034	19,671	19,670	1	0.006	0.007
2035	20,632	20,631	1	0.005	0.006
2036	22,857	22,857	0	0.002	0.002
2037	24,312	24,311	1	0.007	0.009
2038	25,527	25,526	1	0.005	0.006
2039	27,122	27,122	0	-0.002	-0.002
2040	28,576	28,578	-2	-0.010	-0.012

Notes:

Negative indicates a reduction in the customer bill for the 10 MW solar project.

The annual revenue requirements include fixed costs (capital, fixed O&M and firm gas transportation costs) for future generation resources, as well as the three existing solar projects. Revenue requirements from existing facilities are not included as they would be the same for both simulations and would not impact the result. Projected variable costs (fuel, VOM, and emission costs) for all of FPL's generation resources, including existing ones are also included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

New Generation Martin Solar Project
System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

	[1]	[2]	[3]	[4]	[5]
Year	Annual System Total Revenue Requirements with Solar Project $ Millions	Annual System Total Revenue Requirements without Solar Project $ Millions	Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	Differential in Customer Bill $/ 1000 kWH	Differential in Customer Bill $/ 1200 kWH
2008	0	0	0	0.000	0.000
2009	7	0	7	0.065	0.078
2010	29	0	29	0.276	0.331
2011	50	0	50	0.485	0.582
2012	2,937	2,894	43	0.426	0.511
2013	3,065	3,022	44	0.422	0.506
2014	3,397	3,357	40	0.383	0.460
2015	3,649	3,610	39	0.364	0.437
2016	4,468	4,432	36	0.325	0.390
2017	4,934	4,900	35	0.314	0.376
2018	6,539	6,510	29	0.261	0.314
2019	7,054	7,025	28	0.248	0.297
2020	7,875	7,848	26	0.227	0.273
2021	8,722	8,698	24	0.205	0.246
2022	9,164	9,140	24	0.196	0.235
2023	9,126	9,104	23	0.183	0.219
2024	9,714	9,694	20	0.157	0.188
2025	10,581	10,565	16	0.122	0.146
2026	11,196	11,181	15	0.112	0.134
2027	11,940	11,926	14	0.104	0.125
2028	12,526	12,515	10	0.076	0.091
2029	13,252	13,242	9	0.067	0.080
2030	14,166	14,158	8	0.059	0.071
2031	14,994	14,984	10	0.071	0.085
2032	16,241	16,237	4	0.029	0.035
2033	18,297	18,293	4	0.029	0.034
2034	19,671	19,670	1	0.005	0.006
2035	20,631	20,631	0	-0.001	-0.002
2036	22,856	22,857	-1	-0.007	-0.008
2037	24,307	24,311	-4	-0.022	-0.027
2038	25,521	25,526	-5	-0.028	-0.034
2039	27,115	27,122	-7	-0.041	-0.049
2040	28,569	28,578	-9	-0.056	-0.067

Notes:

Negative indicates a reduction in the customer bill for the 75 MW solar project.

The annual revenue requirements include fixed costs (capital, fixed O&M and firm gas transportation costs) for future generation resources, as well as the three existing solar projects. Revenue requirements from existing facilities are not included as they would be the same for both simulations and would not impact the result. Projected variable costs (fuel, VOM, and emission costs) for all of FPL's generation resources, including existing ones are also included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

Q.
Please complete the table below for each of FPL's solar projects.

A.
Please see attached tables.

New Generation DeSoto Solar Project
(do not include system benefits)

	Capital Revenue Requirements ($ millions)	Fixed O&M and Capital Replacement Costs ($ millions)	Total ($ millions)	Impact on Customer Bill of 1,000 kwh ($)	Impact on Customer Bill of 1,200 kwh ($)
2008	0.0	0	0.0	0	0
2009	10.7	0.1	10.8	0.105	0.126
2010	18.1	1.0	19.1	0.182	0.219
2011	17.5	0.9	18.4	0.178	0.214
2012	17.2	1.0	18.1	0.179	0.214
2013	16.7	1.0	17.7	0.171	0.206
2014	15.7	1.1	16.7	0.159	0.190
2015	15.1	1.2	16.3	0.151	0.181
2016	14.6	1.1	15.7	0.143	0.172
2017	14.1	1.2	15.3	0.138	0.166
2018	13.6	1.3	14.9	0.133	0.159
2019	13.1	1.4	14.5	0.128	0.153
2020	12.6	1.5	14.1	0.121	0.146
2021	12.1	1.5	13.6	0.115	0.137
2022	11.6	1.5	13.2	0.108	0.130
2023	11.1	1.6	12.7	0.102	0.123
2024	10.6	1.6	12.3	0.097	0.116
2025	10.1	1.7	11.8	0.091	0.110
2026	9.6	1.7	11.3	0.086	0.103
2027	9.1	1.7	10.9	0.081	0.097
2028	8.6	1.8	10.4	0.076	0.092
2029	8.1	1.9	10.1	0.073	0.087
2030	7.6	2.0	9.6	0.068	0.082
2031	7.1	2.0	9.2	0.064	0.077
2032	6.6	2.1	8.7	0.060	0.072
2033	6.1	2.1	8.3	0.056	0.067
2034	5.6	2.3	7.9	0.052	0.063
2035	5.1	2.4	7.5	0.049	0.059
2036	4.6	2.3	7.0	0.045	0.054
2037	4.1	2.4	6.5	0.041	0.050
2038	3.6	2.5	6.1	0.038	0.045
2039	2.8	2.6	5.5	0.033	0.040
2040	-0.2	2.5	2.3	0.014	0.017

Notes:

As requested, the capital revenue requirements and the O&M requirements shown in this table only include the costs of the solar project. System impacts are not included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

New Generation Space Coast Solar Project
(do not include system benefits)

	Capital Revenue Requirements ($ millions)	Fixed O&M and Capital Replacement Costs ($ millions)	Total ($ millions)	Impact on Customer Bill of 1,000 kwh ($)	Impact on Customer Bill of 1,200 kwh ($)
2008	0.0	0	0.0	0	0
2009	1.0	0.0	1.0	0.010	0.012
2010	7.6	0.3	7.9	0.076	0.091
2011	8.3	0.4	8.8	0.085	0.102
2012	8.1	0.3	8.4	0.083	0.100
2013	7.9	0.4	8.2	0.080	0.096
2014	7.4	0.4	7.8	0.074	0.089
2015	7.1	0.5	7.6	0.070	0.085
2016	6.9	0.4	7.3	0.067	0.080
2017	6.7	0.4	7.1	0.064	0.077
2018	6.5	0.5	6.9	0.062	0.074
2019	6.2	0.5	6.7	0.059	0.071
2020	6.0	0.6	6.6	0.056	0.068
2021	5.8	0.6	6.4	0.054	0.065
2022	5.5	0.5	6.1	0.050	0.060
2023	5.3	0.6	5.9	0.047	0.057
2024	5.1	0.6	5.7	0.045	0.054
2025	4.9	0.6	5.5	0.043	0.051
2026	4.6	0.6	5.2	0.040	0.048
2027	4.4	0.6	5.0	0.037	0.045
2028	4.2	0.6	4.8	0.035	0.042
2029	3.9	0.7	4.6	0.034	0.040
2030	3.7	0.7	4.4	0.032	0.038
2031	3.5	0.9	4.3	0.030	0.036
2032	3.2	0.7	4.0	0.027	0.033
2033	3.0	0.8	3.8	0.026	0.031
2034	2.8	0.8	3.6	0.024	0.029
2035	2.5	0.9	3.4	0.022	0.027
2036	2.3	0.8	3.2	0.020	0.024
2037	2.1	0.8	2.9	0.018	0.022
2038	1.8	0.8	2.7	0.017	0.020
2039	1.6	0.9	2.5	0.015	0.019
2040	0.4	0.9	1.3	0.008	0.010

Notes:

As requested, the capital revenue requirements and the O&M requirements shown in this table only include the costs of the solar project. System impacts are not included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.
These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

New Generation Martin Solar Project
(do not include system benefits)

	Capital Revenue Requirements ($ millions)	Fixed O&M and Capital Replacement Costs ($ millions)	Total ($ millions)	Impact on Customer Bill of 1,000 kwh ($)	Impact on Customer Bill of 1,200 kwh ($)
2008	0.0	0	0.0	0	0
2009	6.7	0.0	6.7	0.065	0.078
2010	29.0	0.0	29.0	0.277	0.333
2011	47.4	4.6	52.0	0.504	0.604
2012	46.7	2.6	49.3	0.485	0.583
2013	45.4	3.1	48.5	0.471	0.565
2014	42.7	2.7	45.4	0.431	0.517
2015	41.2	3.1	44.4	0.410	0.492
2016	39.9	2.8	42.7	0.389	0.467
2017	38.6	3.3	41.8	0.377	0.452
2018	37.2	2.9	40.2	0.358	0.429
2019	35.9	3.4	39.3	0.346	0.415
2020	34.6	3.0	37.6	0.324	0.389
2021	33.2	3.5	36.8	0.310	0.372
2022	31.9	3.2	35.1	0.288	0.346
2023	30.6	3.7	34.3	0.276	0.331
2024	29.2	3.3	32.5	0.257	0.308
2025	27.9	3.8	31.8	0.246	0.295
2026	26.6	3.4	30.0	0.228	0.273
2027	25.2	4.0	29.2	0.218	0.262
2028	23.9	3.6	27.5	0.202	0.242
2029	22.5	4.2	26.7	0.193	0.232
2030	21.2	3.7	24.9	0.177	0.213
2031	19.9	4.3	24.2	0.169	0.203
2032	18.5	3.9	22.4	0.154	0.185
2033	17.2	4.5	21.7	0.147	0.176
2034	15.8	4.0	19.8	0.132	0.159
2035	14.5	4.7	19.2	0.126	0.151
2036	13.1	4.2	17.3	0.112	0.134
2037	11.8	4.9	16.7	0.106	0.127
2038	10.4	4.4	14.8	0.092	0.111
2039	9.0	5.1	14.2	0.087	0.104
2040	7.6	4.5	12.1	0.073	0.087

Notes:

As requested, the capital revenue requirements and the O&M requirements shown in this table only include the costs of the solar project. System impacts are not included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

Q.
Please complete the table below for each of FPL's solar projects.

A.
Please see attached tables.

New Generation DeSoto Solar Project
System Variable O&M and System Fuel Costs - With and Without Solar Project

1000	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	System Costs w/Solar Project					System Costs w/o Solar Project					Differential in annual costs [3]-[8]				
	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [1] + [2] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [6] + [7] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total Revenue Requirements ($ millions)	Impact on Customer Bill of 1,000 KWH	Impact on Customer Bill of 1,200 KWH
2009	0	0.0	0.0	0.00	0.00	0	0.8	0.8	0.01	0.01	0	-1	-1	-0.01	-0.01
2010	0	0.0	0.0	0.00	0.00	0	2.8	2.8	0.03	0.03	0	-3	-3	-0.03	-0.03
2011	0	0.0	0.0	0.00	0.00	0	3.2	3.2	0.03	0.04	0	-3	-3	-0.03	-0.04
2012	115	2,781	2,896	28.5	34.2	115	2,783	2,898	28.5	34.2	0	-2	-2	-0.02	-0.02
2013	117	2,910	3,027	29.3	35.2	117	2,912	3,029	29.4	35.2	0	-2	-2	-0.02	-0.02
2014	122	3,239	3,361	31.9	38.3	122	3,241	3,363	31.9	38.3	0	-2	-2	-0.02	-0.02
2015	125	3,489	3,614	33.4	40.1	125	3,491	3,616	33.5	40.2	0	-2	-2	-0.02	-0.02
2016	125	3,909	4,034	36.8	44.1	125	3,912	4,037	36.8	44.1	0	-3	-3	-0.03	-0.03
2017	129	4,262	4,391	39.5	47.5	129	4,265	4,394	39.6	47.5	0	-3	-3	-0.03	-0.03
2018	131	4,689	4,820	42.9	51.5	131	4,692	4,823	43.0	51.6	0	-3	-3	-0.03	-0.03
2019	137	5,107	5,244	46.2	55.4	137	5,111	5,248	46.2	55.4	0	-4	-4	-0.04	-0.04
2020	148	5,620	5,768	49.7	59.7	148	5,623	5,771	49.8	59.7	0	-3	-3	-0.03	-0.03
2021	159	6,101	6,260	52.7	63.3	159	6,105	6,264	52.8	63.3	0	-4	-4	-0.03	-0.04
2022	185	6,308	6,493	53.4	64.0	185	6,312	6,497	53.4	64.1	0	-4	-4	-0.03	-0.04
2023	190	6,272	6,462	52.0	62.4	190	6,275	6,465	52.0	62.5	0	-3	-3	-0.02	-0.03
2024	198	6,705	6,903	54.5	65.4	198	6,709	6,907	54.5	65.4	0	-4	-4	-0.03	-0.04
2025	211	7,407	7,618	59.0	70.8	211	7,412	7,623	59.0	70.8	0	-5	-5	-0.04	-0.05
2026	225	7,744	7,969	60.5	72.6	225	7,748	7,973	60.5	72.6	0	-4	-4	-0.03	-0.04
2027	236	8,175	8,411	62.8	75.3	236	8,180	8,416	62.8	75.4	0	-5	-5	-0.04	-0.04
2028	248	8,468	8,714	63.9	76.7	248	8,472	8,718	64.0	76.8	0	-4	-4	-0.03	-0.04
2029	257	8,744	9,001	65.0	78.0	258	8,748	9,006	65.0	78.0	-1	-4	-5	-0.04	-0.04
2030	271	9,200	9,471	67.4	80.8	271	9,204	9,475	67.4	80.9	0	-4	-4	-0.03	-0.03
2031	287	9,613	9,900	69.3	83.1	287	9,617	9,904	69.3	83.1	0	-4	-4	-0.03	-0.03
2032	304	10,198	10,502	72.3	86.7	304	10,202	10,506	72.3	86.8	0	-4	-4	-0.03	-0.03
2033	326	11,142	11,468	77.6	93.1	326	11,146	11,472	77.7	93.2	0	-4	-4	-0.03	-0.03
2034	343	11,716	12,059	80.3	96.3	343	11,721	12,064	80.3	96.4	0	-5	-5	-0.03	-0.04
2035	359	12,110	12,469	81.7	98.0	359	12,115	12,474	81.7	98.0	0	-5	-5	-0.03	-0.04
2036	387	13,093	13,480	86.8	104.2	387	13,098	13,485	86.9	104.2	0	-5	-5	-0.03	-0.04
2037	404	13,621	14,025	88.9	106.6	404	13,625	14,029	88.9	106.7	0	-4	-4	-0.03	-0.03
2038	418	14,080	14,498	90.4	108.4	418	14,084	14,502	90.4	108.5	0	-4	-4	-0.02	-0.03
2039	439	14,661	15,100	92.6	111.1	439	14,666	15,105	92.6	111.1	0	-5	-5	-0.03	-0.04
2040	462	15,137	15,599	94.1	112.9	462	15,141	15,603	94.1	112.9	0	-4	-4	-0.02	-0.03

Notes:

Negative indicates a reduction in the customer bill for the 25 MW New Generation DeSoto solar project.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

the Port Everglades Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Florida Power & Light Company
Docket No. 120007-EI
Staff's 1st Set of Interrogatories
Question No. 4
Table 4- Page 1 of 3

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New Generation Space Cost Solar Project
System Variable O&M and System Fuel Costs - With and Without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	System Costs w/Solar Project					System Costs w/o Solar Project					Differential in annual costs [3]-[6]				
	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [1] + [2] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [6] + [7] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total Revenue Requirements ($ millions)	Impact on Customer Bill of 1000 KWH	Impact on Customer Bill of 1,200 KWH
2009	0	0	0	0.0	0.0	0	0	0.0	0.00	0.00	0	0	0	0.00	0.00
2010	0	0	0	0.0	0.0	0	0.8	0.8	0.01	0.01	0	-1	-1	-0.01	-0.01
2011	0	0	0	0.0	0.0	0	1.2	1.2	0.01	0.01	0	-1	-1	-0.01	-0.01
2012	115	2,782	2,897	28.5	34.2	115	2,783	2,898	28.5	34.2	0	-1	-1	-0.01	-0.01
2013	117	2,912	3,029	29.4	35.2	117	2,912	3,029	29.4	35.2	0	0	0	0.00	0.00
2014	122	3,241	3,363	31.8	38.3	122	3,241	3,363	31.9	38.3	0	0	0	0.00	0.00
2015	125	3,490	3,615	33.5	40.1	125	3,491	3,616	33.5	40.2	0	-1	-1	-0.01	-0.01
2016	125	3,911	4,036	36.8	44.1	125	3,912	4,037	36.8	44.1	0	-1	-1	-0.01	-0.01
2017	129	4,264	4,393	39.6	47.5	129	4,265	4,394	39.8	47.5	0	-1	-1	-0.01	-0.01
2018	131	4,690	4,821	42.9	51.5	131	4,692	4,823	43.0	51.6	0	-2	-2	-0.02	-0.02
2019	137	5,109	5,246	46.2	55.4	137	5,111	5,248	46.2	55.4	0	-2	-2	-0.02	-0.02
2020	148	5,622	5,770	49.8	59.7	148	5,623	5,771	49.8	59.7	0	-1	-1	-0.01	-0.01
2021	159	6,103	6,262	52.7	63.3	159	6,105	6,264	52.8	63.3	0	-2	-2	-0.02	-0.02
2022	185	6,310	6,495	53.4	64.1	185	6,312	6,497	53.4	64.1	0	-2	-2	-0.02	-0.02
2023	190	6,274	6,464	52.0	62.4	190	6,275	6,465	52.0	62.5	0	-1	-1	-0.01	-0.01
2024	198	6,708	6,906	54.5	65.4	198	6,709	6,907	54.5	65.4	0	-1	-1	-0.01	-0.01
2025	211	7,410	7,621	58.0	70.8	211	7,412	7,623	58.0	70.8	0	-2	-2	-0.02	-0.02
2026	225	7,747	7,972	60.5	72.6	225	7,748	7,973	60.5	72.6	0	-1	-1	-0.01	-0.01
2027	236	8,178	8,414	62.8	75.3	236	8,180	8,416	62.8	75.4	0	-2	-2	-0.01	-0.02
2028	246	8,471	8,717	64.0	76.7	246	8,472	8,718	64.0	76.8	0	-1	-1	-0.01	-0.01
2029	257	8,747	9,004	65.0	78.0	258	8,748	9,006	65.0	78.0	-1	-1	-2	-0.01	-0.02
2030	271	9,203	9,474	67.4	80.9	271	9,204	9,475	67.4	80.9	0	-1	-1	-0.01	-0.01
2031	287	9,616	9,903	69.3	83.1	287	9,617	9,904	69.3	83.1	0	-1	-1	-0.01	-0.01
2032	304	10,200	10,504	72.3	86.7	304	10,202	10,506	72.3	86.8	0	-2	-2	-0.01	-0.02
2033	326	11,145	11,471	77.6	93.2	326	11,146	11,472	77.7	93.2	0	-1	-1	-0.01	-0.01
2034	343	11,719	12,062	80.3	96.4	343	11,721	12,064	80.3	96.4	0	-2	-2	-0.01	-0.02
2035	359	12,113	12,472	81.7	98.0	359	12,115	12,474	81.7	98.0	0	-2	-2	-0.01	-0.02
2036	387	13,096	13,483	86.8	104.2	387	13,098	13,485	86.9	104.2	0	-2	-2	-0.01	-0.02
2037	404	13,624	14,028	88.9	106.7	404	13,625	14,029	88.9	106.7	0	-1	-1	-0.01	-0.01
2038	418	14,083	14,501	90.4	108.4	418	14,084	14,502	90.4	108.5	0	-1	-1	-0.01	-0.01
2039	439	14,664	15,103	92.6	111.1	439	14,666	15,105	92.6	111.1	0	-2	-2	-0.01	-0.01
2040	462	15,139	15,601	94.1	112.9	462	15,141	15,603	94.1	112.9	0	-2	-2	-0.01	-0.01

Notes:

Negative indicates a reduction in the customer bill for the 10 MW New Generation Space Cost solar project.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

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New Generation Martin Solar Project
System Variable O&M and System Fuel Costs - With and Without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	System Costs w/Solar Project					System Costs w/o Solar Project					Differential in annual costs [3]-[8]				
	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [1] + [2] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [6] + [7] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total Revenue Requirements ($ millions)	Impact on Customer Bill of 1,000 KWH	Impact on Customer Bill of 1,200 KWH
2009	0	0	0	0.0	0.0	0	0	0	0.00	0.00	0	0	0	0.00	0.00
2010	0	0	0	0.0	0.0	0	0.1	0.1	0.00	0.00	0	0	0	0.00	0.00
2011	0	0	0	0.0	0.0	0	1.9	1.9	0.02	0.02	0	-2	-2	-0.02	-0.02
2012	115	2,777	2,892	28.5	34.1	115	2,783	2,898	28.5	34.2	0	-6	-6	-0.06	-0.07
2013	117	2,907	3,024	29.3	35.2	117	2,912	3,029	29.4	35.2	0	-5	-5	-0.05	-0.06
2014	122	3,236	3,358	31.8	38.2	122	3,241	3,363	31.9	38.3	0	-5	-5	-0.05	-0.06
2015	125	3,486	3,611	33.4	40.1	125	3,491	3,616	33.5	40.2	0	-5	-5	-0.05	-0.06
2016	125	3,905	4,030	36.7	44.1	125	3,912	4,037	36.8	44.1	0	-7	-7	-0.06	-0.06
2017	129	4,258	4,387	39.5	47.4	129	4,265	4,394	39.6	47.5	0	-7	-7	-0.06	-0.06
2018	131	4,683	4,814	42.9	51.5	131	4,692	4,823	43.0	51.6	0	-9	-9	-0.08	-0.10
2019	137	5,102	5,239	46.1	55.3	137	5,111	5,248	46.2	55.4	0	-9	-9	-0.08	-0.10
2020	148	5,614	5,762	49.7	59.8	148	5,623	5,771	49.8	59.7	0	-8	-9	-0.08	-0.09
2021	159	6,095	6,254	52.7	63.2	156	6,105	6,264	52.8	63.3	0	-10	-10	-0.08	-0.10
2022	185	6,303	6,488	53.3	64.0	185	6,312	6,497	53.4	64.1	0	-9	-9	-0.07	-0.09
2023	190	6,266	6,456	52.0	62.4	190	6,275	6,465	52.0	62.5	0	-9	-9	-0.07	-0.09
2024	198	6,699	6,897	54.4	65.3	198	6,709	6,907	54.5	65.4	0	-10	-10	-0.08	-0.09
2025	211	7,399	7,610	58.9	70.7	211	7,412	7,623	59.0	70.8	0	-13	-13	-0.10	-0.12
2026	225	7,736	7,961	60.4	72.5	225	7,748	7,973	60.5	72.6	0	-12	-12	-0.09	-0.11
2027	236	8,168	8,404	62.7	75.2	236	8,180	8,416	62.8	75.4	0	-12	-12	-0.09	-0.11
2028	246	8,459	8,705	63.9	76.6	246	8,472	8,718	64.0	76.8	0	-13	-13	-0.10	-0.11
2029	257	8,736	8,993	64.9	77.9	258	8,748	9,006	65.0	78.0	-1	-12	-13	-0.09	-0.11
2030	271	9,192	9,463	67.3	80.8	271	9,204	9,475	67.4	80.9	0	-12	-12	-0.09	-0.10
2031	287	9,607	9,894	69.2	83.1	287	9,617	9,904	69.3	83.1	0	-10	-10	-0.07	-0.08
2032	304	10,189	10,493	72.2	86.7	304	10,202	10,506	72.3	86.8	0	-13	-13	-0.09	-0.11
2033	326	11,134	11,460	77.6	93.1	326	11,146	11,472	77.7	93.2	0	-12	-12	-0.08	-0.10
2034	343	11,708	12,051	80.2	96.3	343	11,721	12,064	80.3	96.4	0	-13	-13	-0.09	-0.10
2035	359	12,102	12,461	81.6	97.9	359	12,115	12,474	81.7	98.0	0	-13	-13	-0.09	-0.10
2036	387	13,086	13,473	86.8	104.1	387	13,098	13,485	86.9	104.2	0	-12	-12	-0.08	-0.09
2037	404	13,812	14,216	88.8	106.6	404	13,825	14,229	88.9	106.7	0	-13	-13	-0.08	-0.10
2038	418	14,072	14,490	90.3	108.4	418	14,084	14,502	90.4	108.5	0	-12	-12	-0.07	-0.09
2039	439	14,653	15,092	92.5	111.0	439	14,666	15,105	92.6	111.1	0	-13	-13	-0.08	-0.10
2040	462	15,128	15,590	94.0	112.8	462	15,141	15,603	94.1	112.9	0	-13	-13	-0.08	-0.09

Notes:

Negative indicates a reduction in the customer bill for the 75 MW New Generation Martin Solar project.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

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Q.
Please complete the table below for each of FPL's solar projects.

A.
Please see response to Interrogatory No. 6.

Q.
Please complete the table below for each of FPL's solar projects.

A.
Please see attached tables.

New Generation DeSoto Solar Project
Annual Emission Costs - with and without Solar Project

1000

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Emission Related Revenue Requirements Costs with Solar Project				Emission Related Revenue Requirements Costs without Solar Project				[4]- [8] Differential in Revenue Requirements ($ millions)	Differential in Customer Bill $/1,000 kwh	Differential in Customer Bill $/1,200 kwh
	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)			
2012	0.000	-1.633	-3.830	-5.462	0.000	-1.629	-3.817	-5.445	-0.017	0.000	0.000
2013	0.000	-2.254	-6.011	-8.264	0.000	-2.252	-6.004	-8.256	-0.009	0.000	0.000
2014	0.000	-1.031	-6.521	-7.552	0.000	-1.030	-6.517	-7.547	-0.005	0.000	0.000
2015	0.000	-0.978	-6.674	-7.651	0.000	-0.977	-6.670	-7.647	-0.004	0.000	0.000
2016	0.000	-1.049	-7.468	-8.518	0.000	-1.048	-7.464	-8.513	-0.005	0.000	0.000
2017	0.000	-1.165	-7.738	-8.904	0.000	-1.164	-7.735	-8.899	-0.005	0.000	0.000
2018	1,187.412	-1.322	-8.349	1,177.740	1,188.086	-1.321	-8.345	1,178.420	-0.680	-0.006	-0.007
2019	1,283.942	-1.314	-8.612	1,274.016	1,284.732	-1.313	-8.606	1,274.812	-0.796	-0.007	-0.008
2020	1,450.042	-1.232	-8.183	1,440.627	1,450.898	-1.230	-8.176	1,441.491	-0.864	-0.007	-0.009
2021	1,626.207	-1.297	-8.553	1,616.357	1,627.066	-1.296	-8.547	1,617.223	-0.866	-0.007	-0.009
2022	1,721.108	-1.426	-9.426	1,710.256	1,722.001	-1.426	-9.422	1,711.154	-0.898	-0.007	-0.009
2023	1,732.651	-1.505	-10.098	1,721.048	1,733.619	-1.505	-10.095	1,722.020	-0.972	-0.008	-0.009
2024	1,892.864	-1.511	-10.197	1,881.156	1,893.870	-1.510	-10.194	1,882.166	-1.009	-0.008	-0.010
2025	2,056.296	-1.593	-10.005	2,044.697	2,057.385	-1.592	-10.000	2,045.793	-1.095	-0.008	-0.010
2026	2,232.824	-1.652	-10.185	2,220.988	2,233.997	-1.651	-10.179	2,222.167	-1.179	-0.009	-0.011
2027	2,474.358	-1.654	-10.204	2,462.500	2,475.675	-1.653	-10.198	2,463.824	-1.324	-0.010	-0.012
2028	2,676.555	-1.719	-10.579	2,664.257	2,677.972	-1.718	-10.572	2,665.681	-1.425	-0.010	-0.013
2029	2,856.622	-1.846	-11.373	2,843.403	2,858.211	-1.846	-11.367	2,844.998	-1.595	-0.012	-0.014
2030	3,075.812	-1.947	-12.022	3,061.843	3,077.386	-1.947	-12.017	3,063.422	-1.578	-0.011	-0.013
2031	3,319.145	-2.045	-12.498	3,304.602	3,320.763	-2.044	-12.494	3,306.225	-1.623	-0.011	-0.014
2032	3,701.189	-2.121	-12.793	3,686.276	3,702.928	-2.120	-12.789	3,688.020	-1.744	-0.012	-0.014
2033	4,324.017	-2.176	-12.911	4,308.931	4,325.886	-2.175	-12.906	4,310.805	-1.874	-0.013	-0.015
2034	4,796.387	-2.243	-13.247	4,780.896	4,798.396	-2.243	-13.243	4,782.910	-2.014	-0.013	-0.016
2035	5,200.696	-2.306	-13.586	5,184.804	5,202.759	-2.306	-13.582	5,186.871	-2.067	-0.014	-0.016
2036	6,010.664	-2.350	-13.604	5,994.710	6,012.987	-2.349	-13.601	5,997.037	-2.326	-0.015	-0.018
2037	6,589.920	-2.423	-13.994	6,573.503	6,592.303	-2.422	-13.990	6,575.890	-2.387	-0.015	-0.018
2038	7,187.731	-2.484	-14.274	7,170.974	7,190.292	-2.483	-14.270	7,173.540	-2.566	-0.016	-0.019
2039	7,891.911	-2.574	-14.710	7,874.627	7,894.403	-2.573	-14.707	7,877.122	-2.495	-0.015	-0.018
2040	8,597.568	-2.638	-15.031	8,579.900	8,600.247	-2.637	-15.028	8,582.582	-2.682	-0.016	-0.019

Notes:

Negative indicates a reduction in the customer bill .

The annual costs include only the system emission costs.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

In this analysis FPL has not assigned a value to the reduction in historical emissions due to the solar projects. For projections starting in 2012, FPL has used its ENV II Emission Price Forecast, as used during the 2011 Ten Year Site Plan and the Need Filing for the modernization of Port Everglades

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Space Coast Next Generation Solar Project
Annual Emission Costs - with and without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Emission Related Revenue Requirements Costs with Solar Project				Emission Related Revenue Requirements Costs without Solar Project						
	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	[4]- [8] Differential in Revenue Requirements ($ millions)	Differential in Customer Bill $/1,000 kwh	Differential in Customer Bill $/1,200 kwh
2012	0.000	-1.630	-3.822	-5.452	0.000	-1.629	-3.817	-5.445	-0.007	0.000	0.000
2013	0.000	-2.252	-6.007	-8.260	0.000	-2.252	-6.004	-8.256	-0.004	0.000	0.000
2014	0.000	-1.030	-6.519	-7.549	0.000	-1.030	-6.517	-7.547	-0.002	0.000	0.000
2015	0.000	-0.977	-6.672	-7.649	0.000	-0.977	-6.670	-7.647	-0.002	0.000	0.000
2016	0.000	-1.049	-7.466	-8.515	0.000	-1.048	-7.464	-8.513	-0.002	0.000	0.000
2017	0.000	-1.165	-7.736	-8.901	0.000	-1.164	-7.735	-8.899	-0.002	0.000	0.000
2018	1,187.871	-1.321	-8.347	1,178.202	1,188.086	-1.321	-8.345	1,178.420	-0.218	-0.002	-0.002
2019	1,284.468	-1.314	-8.608	1,274.546	1,284.732	-1.313	-8.606	1,274.812	-0.266	-0.002	-0.003
2020	1,450.613	-1.231	-8.179	1,441.202	1,450.898	-1.230	-8.176	1,441.491	-0.289	-0.002	-0.003
2021	1,626.791	-1.297	-8.549	1,616.945	1,627.066	-1.296	-8.547	1,617.223	-0.278	-0.002	-0.003
2022	1,721.704	-1.426	-9.423	1,710.854	1,722.001	-1.426	-9.422	1,711.154	-0.299	-0.002	-0.003
2023	1,733.296	-1.505	-10.096	1,721.695	1,733.619	-1.505	-10.095	1,722.020	-0.324	-0.003	-0.003
2024	1,893.520	-1.510	-10.195	1,881.814	1,893.870	-1.510	-10.194	1,882.166	-0.351	-0.003	-0.003
2025	2,057.006	-1.593	-10.002	2,045.411	2,057.385	-1.592	-10.000	2,045.793	-0.381	-0.003	-0.004
2026	2,233.640	-1.651	-10.181	2,221.807	2,233.997	-1.651	-10.179	2,222.167	-0.359	-0.003	-0.003
2027	2,475.236	-1.653	-10.201	2,463.382	2,475.675	-1.653	-10.198	2,463.824	-0.442	-0.003	-0.004
2028	2,677.499	-1.719	-10.574	2,665.206	2,677.972	-1.718	-10.572	2,665.681	-0.475	-0.003	-0.004
2029	2,857.703	-1.846	-11.370	2,844.487	2,858.211	-1.846	-11.367	2,844.998	-0.511	-0.004	-0.004
2030	3,076.838	-1.947	-12.019	3,062.873	3,077.386	-1.947	-12.017	3,063.422	-0.549	-0.004	-0.005
2031	3,320.175	-2.044	-12.495	3,305.635	3,320.763	-2.044	-12.494	3,306.225	-0.590	-0.004	-0.005
2032	3,702.375	-2.120	-12.790	3,687.465	3,702.928	-2.120	-12.789	3,688.020	-0.555	-0.004	-0.005
2033	4,325.206	-2.175	-12.908	4,310.123	4,325.886	-2.175	-12.906	4,310.805	-0.682	-0.005	-0.006
2034	4,797.666	-2.243	-13.245	4,782.178	4,798.396	-2.243	-13.243	4,782.910	-0.733	-0.005	-0.006
2035	5,202.071	-2.306	-13.584	5,186.181	5,202.759	-2.306	-13.582	5,186.871	-0.689	-0.005	-0.005
2036	6,012.142	-2.349	-13.602	5,996.191	6,012.987	-2.349	-13.601	5,997.037	-0.846	-0.005	-0.007
2037	6,591.508	-2.423	-13.992	6,575.094	6,592.303	-2.422	-13.990	6,575.890	-0.796	-0.005	-0.006
2038	7,189.439	-2.483	-14.271	7,172.685	7,190.292	-2.483	-14.270	7,173.540	-0.855	-0.005	-0.006
2039	7,893.616	-2.574	-14.708	7,876.334	7,894.403	-2.573	-14.707	7,877.122	-0.788	-0.005	-0.006
2040	8,599.260	-2.637	-15.030	8,581.593	8,600.247	-2.637	-15.028	8,582.582	-0.989	-0.006	-0.007

Notes:

Negative indicates a reduction in the customer bill .

The annual costs include only the system emission costs.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

In this analysis FPL has not assigned a value to the reduction in historical emissions due to the solar projects. For projections starting in 2012, FPL has used its ENV II Emission Price Forecast, as used during the 2011 Ten Year Site Plan and the Need Filing for the modernization of Port Everglades

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New Generation Martin Solar Project
Annual Emission Costs - with and without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Emission Related Revenue Requirements Costs with Solar Project				Emission Related Revenue Requirements Costs without Solar Project						
	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	[4]- [8] Differential in Revenue Requirements ($ millions)	Differential in Customer Bill $/1,000 kwh	Differential in Customer Bill $/1,200 kwh
2012	0.000	-1.639	-3.854	-5.493	0.000	-1.629	-3.817	-5.445	-0.047	0.000	-0.001
2013	0.000	-2.258	-6.023	-8.280	0.000	-2.252	-6.004	-8.256	-0.024	0.000	0.000
2014	0.000	-1.032	-6.529	-7.561	0.000	-1.030	-6.517	-7.547	-0.014	0.000	0.000
2015	0.000	-0.979	-6.679	-7.658	0.000	-0.977	-6.670	-7.647	-0.011	0.000	0.000
2016	0.000	-1.051	-7.475	-8.526	0.000	-1.048	-7.464	-8.513	-0.014	0.000	0.000
2017	0.000	-1.167	-7.746	-8.912	0.000	-1.164	-7.735	-8.899	-0.014	0.000	0.000
2018	1,186,279	-1.324	-8.358	1,176,596	1,188,086	-1.321	-8.345	1,178.420	-1.824	-0.016	-0.019
2019	1,282.597	-1.316	-8.622	1,272.659	1,284.732	-1.313	-8.606	1,274.812	-2.154	-0.019	-0.023
2020	1,448.680	-1.234	-8.196	1,439,249	1,450.898	-1.230	-8.176	1,441.491	-2.242	-0.019	-0.023
2021	1,624.662	-1.300	-8.565	1,614.798	1,627.066	-1.296	-8.547	1,617.223	-2.425	-0.020	-0.025
2022	1,719.731	-1.428	-9.433	1,708.871	1,722.001	-1.426	-9.422	1,711.154	-2.283	-0.019	-0.023
2023	1,731.038	-1.506	-10.103	1,719.428	1,733.619	-1.505	-10.095	1,722.020	-2.592	-0.021	-0.025
2024	1,891.203	-1.512	-10.204	1,879.488	1,893.870	-1.510	-10.194	1,882.166	-2.678	-0.021	-0.025
2025	2,054.353	-1.595	-10.014	2,042.745	2,057.385	-1.592	-10.000	2,045.793	-3.048	-0.024	-0.028
2026	2,230.734	-1.653	-10.195	2,218.885	2,233.997	-1.651	-10.179	2,222.167	-3.281	-0.025	-0.030
2027	2,472.383	-1.656	-10.216	2,460.511	2,475.675	-1.653	-10.198	2,463.824	-3.313	-0.025	-0.030
2028	2,673.897	-1.721	-10.592	2,661.584	2,677.972	-1.718	-10.572	2,665.681	-4.097	-0.030	-0.036
2029	2,853.762	-1.848	-11.384	2,840.530	2,858.211	-1.846	-11.367	2,844.998	-4.468	-0.032	-0.039
2030	3,072.803	-1.949	-12.033	3,058.821	3,077.386	-1.947	-12.017	3,063.422	-4.600	-0.033	-0.039
2031	3,316.719	-2.046	-12.507	3,302.166	3,320.763	-2.044	-12.494	3,306.225	-4.060	-0.028	-0.034
2032	3,697.791	-2.122	-12.803	3,682.866	3,702.928	-2.120	-12.789	3,688.020	-5.154	-0.035	-0.043
2033	4,320.448	-2.177	-12.920	4,305.350	4,325.886	-2.175	-12.906	4,310.805	-5.454	-0.037	-0.044
2034	4,792.368	-2.245	-13.257	4,776.866	4,798.396	-2.243	-13.243	4,782.910	-6.044	-0.040	-0.048
2035	5,196.376	-2.308	-13.596	5,180.472	5,202.759	-2.306	-13.582	5,186.871	-6.398	-0.042	-0.050
2036	6,006.653	-2.351	-13.613	5,990.689	6,012.987	-2.349	-13.601	5,997.037	-6.348	-0.041	-0.049
2037	6,585.154	-2.424	-14.003	6,568.727	6,592.303	-2.422	-13.990	6,575.890	-7.163	-0.045	-0.054
2038	7,182.973	-2.485	-14.282	7,166.206	7,190.292	-2.483	-14.270	7,173.540	-7.333	-0.046	-0.055
2039	7,886.534	-2.575	-14.717	7,869.242	7,894.403	-2.573	-14.707	7,877.122	-7.880	-0.048	-0.058
2040	8,591.930	-2.639	-15.038	8,574.253	8,600.247	-2.637	-15.028	8,582.582	-8.328	-0.050	-0.060

Notes:

Negative indicates a reduction in the customer bill .

The annual costs include only the system emission costs.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

In this analysis FPL has not assigned a value to the reduction in historical emissions due to the solar projects. For projections starting in 2012, FPL has used its ENV II Emission Price Forecast, as used during the 2011 Ten Year Site Plan and the Need Filing for the modernization of Port Everglades

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Q
Please provide a summary of FPL's findings, at this time, with respect to the performance of FPL's DeSoto, Space Coast, and Martin solar facilities.

A
Desoto:
Performance has been good with generation in 2011 of 51,560 MWh and a capacity factor of 23.5%. There were several equipment failures that caused a loss of generation with the most significant being an underground cable fault on the main feeder circuit between Sunshine Substation and Desoto's main breaker. This resulted in the site being off line for 9 days. The cable fault was caused by a manufacturing defect for which the cost to repair was covered by the cable vendor.

Space Coast:
Performance has been good with generation in 2011 of 18,720 MWh and a capacity factor of 21.4%. There were no major equipment failures that affected generation.

FPL has implemented several improvements at Desoto and Space Coast that have helped maintain a high level of performance. The sites are continuously monitored by our Fleet Performance and Diagnostic Center (FPDC) and the data acquisition system has been configured to initiate alert messages to the FPDC and solar operations personnel for all off normal conditions. Remote control capability of the inverters was added to allow for immediate response to certain off normal conditions when the site is not occupied. Comparison of inverter inputs and outputs are monitored to determine if there are any equipment deficiencies affecting performance. Most maintenance activities are performed at nights or when there are low solar conditions.

Martin:
Performance has been below expectations with generation in 2011 of 28,982 MWh and a capacity factor of 4.4%. The primary reason for the low generation was a Heat Transfer Fluid (HTF) release event which occurred on 06/01/11. The HTF system experienced a high pressure excursion which lifted a safety relief valve on an overflow vessel. FPL has determined that the primary cause of the HTF event was a vendor error in implementing a modification to the control system logic, coupled with water leaks into the HTF system through the feedwater preheaters. The Martin solar site was shutdown for approximately four months after the event for remediation of the soil that was affected by the HTF release, repair of plant equipment and implementation of counter measures to prevent recurrence. The entire Martin Unit 8 combined

cycle plant was also shutdown for approximately two months in 2011 to complete planned maintenance. The solar site cannot operate when Martin Unit 8 is not operating. Martin solar performance is expected to improve starting the second quarter of 2012 with implementation of HTF counter measures.

Q.
Based on the actual data provided in FPL's monthly solar operation status reports, please explain why/ how Martin solar has had months with negative O&M.

A.
Martin solar had two months with negative ECRC O&M actual expenses (August and December) on the monthly solar operations status report in 2011. The reason for the negative monthly ECRC O&M actual expenses is addressed below:

August
The August 2011 ECRC negative O&M expense of ($4,370,565) is due to an August transfer in error of the heat transfer fluid release expenses from ECRC O&M to Base O&M. The error was corrected by reversing the transfer in September 2011.

December
The December 2011 ECRC negative O&M expense of ($4,140,110) is the result of a $4,500,000 payment from Lauren Engineers & Constructors, Inc. ("Lauren") which provided engineering, procurement and construction support services for the project. FPL and Lauren entered into an agreement whereby Lauren paid FPL $4,500,000 in December 2011 to help defray expenses for unplanned maintenance and repairs (including the heat transfer fluid release) incurred by the Martin solar plant in 2011.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 20 day of March, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan Enjamio, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 1, 2 , 4 through 6, and co-sponsored response to Interrogatory number 3 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-8) in Docket No(s). 120007-EI, and that the responses are true and correct based on his personal knowledge.

Juan Enjamio

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20 day of March, 2012.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lily A Rodriguez
My Commission DD854399
Expires 02/13/2013

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 22nd day of March, 2012, 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 answers to interrogatory numbers 7 and 8, and she co-sponsored the response to Interrogatory number 3 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-8) in Docket No(s). 120007-EI, and that the responses are 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 22nd day of March, 2012.

Notary Public
~~State of Florida~~, at Large

My Commission Expires:

Notary Public State of Florida
Jessica Alexander Johnson
My Commission EE108855
Expires 03/02/2015

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 21st day of March, 2012, 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 co-sponsored response to Interrogatory number 3 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-8) in Docket No(s). 120007-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 21st day of March, 2012.

Iwanda S. Jenkins
Notary Public
State of Florida, at Large

My Commission Expires:

NOTARY PUBLIC-STATE OF FLORIDA
Iwanda S. Jenkins
Commission # DD827829
Expires: NOV. 19, 2012
BONDED THRU ATLANTIC BONDING CO., INC.

2

FPL's Response to Staff's Amended 2nd Set of Interrogatories (Nos. 9-21)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	Docket No: 120007-EI Date: April 20, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S AMENDED SECOND SET OF INTERROGATORIES (NOS. 9-21)

Florida Power & Light Company ("FPL"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-12-0060-PCO-EI, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff") Amended Second Set of Interrogatories (Nos. 9-21).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the documents, if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these responses provide all of the information that FPL obtained after a reasonable and diligent search

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conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is duplicative not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the Florida Public Service Commission in this docket. To require any non-regulated entities to

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participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses.

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II. Responses

Attached hereto are FPL's answers to Interrogatory Nos. 9 through 21 of Staff's Amended Second Set of Interrogatories consistent with its objections, together with the affidavits of the persons providing the answers.

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John T. Butler, Esq.
Assistant General Counsel-Regulatory
Maria J. Moncada, Esq.
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Telephone: (561) 304-5795
Facsimile: (561) 691-7135

By: _____
Maria José Moncada
Fla. Bar No. 0773301

CERTIFICATE OF SERVICE
Docket No. 120007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by overnight delivery*, electronic mail and United States Mail on this 20th day of April 2012 to the following:

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By: _____
Maria Jose Moncada
Fla. Bar No. 0773301

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Q.
FPL's solar operation status reports for August 2011 and December 2011, indicate that the O&M costs associated with Martin Solar were negative. Please explain why these values are negative.

A.
See response to Staff's First Set of Interrogatories, Question 8.

Q.
Based on the actual data provided in FPL's monthly solar operation status reports, please explain why the output of the Martin Next Generation Solar Center in the last five months of 2011 has been relatively low when compared to projected performance.

A.
The testimony of Roxane R. Kennedy filed with the Commission on April 2, 2012, for the Environmental Cost Recovery Clause Docket No. 120007-EI, addresses 2011 performance of the Martin Next Generation Solar Center ("Martin Solar"). The lower net generation output in the last five months of 2011 was primarily due to: Martin Solar being offline, as a result of a June 1, 2011 heat transfer fluid release ("HTF"), for soil remediation, repair of plant equipment and implementation of countermeasures to prevent recurrence, feedwater pre-heater repairs, and planned and unplanned outages at the interconnected Martin Unit 8 combined-cycle plant, during the period.

Martin Solar has seen significant performance improvements through March 2012 when compared to the 2011 period August - December. In recent weeks, solar field peak energy production has exceeded the design output of 75 MW. FPL expects the plant to reach its full operating capability and produce fossil-fuel savings and reduce emissions for the benefit of FPL customers and the state of Florida for years to come.

Q.
Based on the data collected in 2011 for FPL's Space Coast and De Soto solar projects, does FPL believe either project can reliably contribute during times of peak load?

A.
FPL has not yet gathered sufficient operational data from these projects to determine to what extent, if any, they can be counted on to reliably contribute firm capacity to FPL's system at time of system peak.

To make this determination FPL will be evaluating their projected impact on long-term generation resource planning, as well as shorter term operational issues such as unit commitment, economic dispatch, operating reserves, load-flow and protection/stability (i.e. transmission) issues. To support this evaluation, FPL is continuing to gather operating data and reviewing industry data and methods.

Q.
At any point in time did FPL shift from using manual calculations, to develop the information provided in its monthly solar operation status report, to automated calculations?

a. If yes, when did FPL make this change?

A.

No. FPL's original intent was to develop an automated program that would serve as a "stand alone" application to calculate the amount of displaced natural gas, fuel oil and coal resulting from the operation of its Next Generation Solar Centers. After several months of development, FPL came to the conclusion that it could not create an automated program that was capable of performing all of the necessary calculations without the need for several manual steps. Therefore, FPL made several refinements to its manual process and is now using a "hybrid" process whereby part of the process utilizes automation and part of the process involves manual calculations. Data retrieval and preliminary marginal unit identification is accomplished through automation. Manual steps include a detailed review of unit data as well as the final calculations of total displaced fuel. With a manual review of hourly unit data, FPL can be more detailed in its assignment of displaced fuel. While any method employed, whether manual, fully automated or a combination of both can only be used to approximate the amount of displaced fuel, FPL's current process delivers consistent results in an efficient manner.

Q.

Referencing the tables found on page 2 of 3 of FPL's solar operation status report. Please describe the manual calculations performed by FPL to develop the values contained in rows 5, 6, 9, and 10.

A.

For the values contained in rows 5 and 6 (and 7, for no. 14 of Staff's Second Set of Interrogatories); FPL utilizes historical data from its Plant Information (PI) system to populate a spreadsheet template with specific data from all of its generating units for every hour of each day. This hourly data includes load level, heat rate and fuel mix for each unit. FPL groups this hourly unit data into nine generation classes: 1) Scherer Unit 4; 2) St. John's Units 1 and 2 (SJRPP); 3) Combined Cycle; 4) Putnam; 5) Simple Cycle Peaking; 6) Conventional; 7) Aircraft Gas Turbines (Gas); 8) Fort Myers (Peaking); and 9) Aircraft Gas Turbines (Oil). A weighted average cost of generation ($/MWh) for each generation class is then calculated utilizing current dispatch prices for natural gas, heavy oil, light oil and coal. By comparing the specific hourly load level of each unit to its typical high and low limits, FPL determines how much of each generation class is available to regulate with system load for each hour. The generation cost information coupled with the regulation availability of each generation class is used to determine the marginal generation class during each hour. The marginal generation class in each hour is the generation that is regulating to meet changes in the system load. Therefore, the methodology for fuel displacement assigns the solar impact to the marginal generation class each hour. For example, if combined cycle units are the highest cost units regulating with system load, then the solar output is assigned as a displacement of combined cycle generation and the associated fuel type not being consumed (in this case, natural gas). This process is carried out for every hour of each month. The results, including the displaced generation class and the MMBtu/MWh of fuel displaced (by fuel type), are tabulated in a separate monthly file. When the actual hourly solar output, by facility, is available after month-end, the hourly output of each solar facility is multiplied by the hourly MMBtu/MWh factor that was derived in the above steps. This process yields the total MMBtu's of fuel, by type, that each solar facility displaced during the month.

The calculation of data reported in rows 9,10,(and 11 for no. 14 of Staff's Second Set of Interrogatories) FPL uses the MW net generation for each solar facility from the PI system and calculates the avoided emissions (reductions) for CO2, NOx, SO2 and Hg using the marginal unit that was determined as described above. For each of the generation classes used on the determination of the displaced fuel, FPL has selected an emission factor based on the actual reported emissions from the Continuous Emission Monitoring Systems (CEMS) or

by using the emission factor developed by EPA for the reporting of emissions from a specific combustion source type. For example, the NOx emission reduction for an hour where the marginal unit is Putnam is calculated using the most recent NOx emission factor which was calculated using the CEMS recorded emission factor (0.35242 lb/mmBtu) and then multiplied by the calculated displaced mmBtu for that hour. The emission factors are expressed in units of lb/mmBtu for each emission reported (CO2, NOx, SO2 and Hg) and the total emission reductions are a factor of each rate and the MWh net generation for each hour summed across all hours in a month for each unit. It is important to note that a unit's net generation is negative when the station service (inverters, switchroom service, pumps, etc.) exceeds the gross generation and emission reductions are reported as negative.

Q.

Referencing the tables found on page 2 of 3 of FPL's solar operation status report. Please describe the manual calculations performed by FPL to develop the values contained in rows 7 and 11.

A.

Please refer to the description provided in response to Staff's Second Set of Interrogatories, no. 13.

Q.
Referencing the tables found on page 2 of 3 of FPL's solar operation status report. Please explain how Martin Solar is displacing coal generation.

A.

Due to the significant drop in natural gas prices, combined cycle generation has become more economical than coal generation on FPL's system. This reversal in generation costs, coupled with mild weather during January, resulted in coal units regulating much more with system load as opposed to being baseloaded throughout most of the daylight hours. Simply put, coal generation is now on the margin more often than it was in the past. With coal units now on the margin during many afternoon hours, the output of the solar facilities is frequently displacing the consumption of coal. For example, if the SJRPP units were the highest cost units in FPL's generation stack on a particular day, as soon as the units regulate up to meet an increase in load, they become the marginal units on the system. To the extent that any of FPL's solar facilities are producing power during that time period, coal is being displaced by the amount of solar output. Continuing with the example, if Martin Solar is producing 75 MW of power, the result is that 75 MW less of the SJRPP units is needed to meet load, and the equivalent amount of coal MMBtu's has been displaced by Martin Solar. Although Martin Solar is used in lieu of natural gas duct burning on Martin Unit 8, FPL does not look at Martin Solar as a straightforward displacement of natural gas. FPL evaluates the output of Martin Solar identical to its other solar facilities when determining the fuel type and quantity that is displaced.

Q.
Referencing the tables found on page 3 of 3 of FPL's January 2012 solar operation status report. For comparison purposes, please provide simulated approximations of the same information contained in each table.

a. Please discuss and or explain any differences when compared to FPL's original filing.

A.
FPL has modified the computations shown on page 3 of 3 of FPL's January 2012 solar operation status report using the energy output as projected in the original filing in 2008. The energy output (both originally projected and actual) is shown below:

Energy Output of Solar Projects

	(1) Energy Originally Projected Jan 2012 MWH	(2) Actual Energy Generated Jan 2012 MWH	(2)-(1) Difference MWH	Difference %
DeSoto	3,233	3,707	474	15%
Space Coast	1,216	1,540	324	27%
Martin	12,645	5,017	-7,628	-60%

The actual generation of both the DeSoto and Space Cost facilities exceeded the original projections (by 15% and 27% respectively). The generation projections were based on expected average insolation levels for the month of January; the actual generation was based on actual insolation for January 2012.

The actual generation of performance of Martin Solar was below original expectations (by approximately 60%). FPL is implementing countermeasures at the Martin solar site to prevent recurrence of a previous release of heat transfer fluid; the full solar facility was not available for generation as a result. (Please see FPL's response to Staff Interrogatory 7 and testimony of Roxane Kennedy filed on April 2, 2012 for a more detailed explanation of the performance of Martin Solar.)

The comparison of fuel and air-emissions avoided by the three projects follows the differences in generation; using the actual DeSoto and Space Coast facilities results in higher reductions in fuel and air emissions than originally projected, while the Martin Solar facility results in lower reductions than originally projected. Please see attachments I and II

Table 16-1

Emissions Avoided by Solar Generation - January 2012
Based on Generation Originally Projected

		CO2 reductions tons	NOX reductions tons	SO2 reductions tons	Hg reductions tons
5	DeSoto	1,770	1	2	0
6	Space Coast	632	0	1	0
7	Martin	5,807	3	4	0
8	Total	8,210	4	6	0.58

Emissions Avoided by Solar Generation - January 2012
Based on Actual Generation

		CO2 reductions tons	NOX reductions tons	SO2 reductions tons	Hg reductions tons
1	DeSoto	2,030	1	2	0.20
2	Space Coast	800	0	1	0.07
3	Martin	2,304	1	2	0.14
4	Total	5,134	3	5	0.41

Difference

		CO2 reductions tons	NOX reductions tons	SO2 reductions tons	Hg reductions tons
9	DeSoto	259	0	0	0.03
10	Space Coast	169	0	0	0.01
11	Martin	-3,503	-2	-2	-0.21
12	Total	-3,075	-2	-2	-0.17

Table 16-1

Fuel Avoided by Solar Generation - January 2012
Based on Generation Originally Projected

		Natural Gas Displaced (MCF)	Cost of Natural Gas ($/MCF)	Cost of Natural Gas $	Oil Displaced (BBls)	Cost Of Oil (BBLs)	Cost of Oil $	Coal Displaced (tons)	Cost Of Coal ($/ton)	Cost of Coal $
5	DeSoto	16,060	$5.39	$86,615	1	$82.78	69	380	$82.55	31,369
6	Space Coast	6,370	$5.39	$34,356	0	$82.78	27	117	$82.55	9,690
7	Martin	71,999	$5.39	$388,314	2	$82.78	185	722	$82.55	59,622
8	Total	94,428	$5.39	$509,286	3	$82.78	$281	1,220	$82.55	$100,682

Fuel Avoided by Solar Generation - January 2012
Based on Actual Generation

		Natural Gas Displaced (MCF)	Cost of Natural Gas ($/MCF)	Cost of Natural Gas $	Oil Displaced (BBls)	Cost Of Oil (BBLs)	Cost of Oil $	Coal Displaced (tons)	Cost Of Coal ($/ton)	Cost of Coal $
1	DeSoto	18,413	$5.39	$99,307	1	$82.78	79	436	$82.55	35,966
2	Space Coast	8,070	$5.39	$43,523	0	$82.78	34	149	$82.55	12,276
3	Martin	28,565	$5.39	$154,060	1	$82.78	74	287	$82.55	23,654
4	Total	55,048	$5.39	$296,891	2	$82.78	$186	871	$82.55	$71,896

Difference

		Natural Gas Displaced (MCF)	Cost of Natural Gas ($/MCF)	Cost of Natural Gas $	Oil Displaced (BBls)	Cost Of Oil (BBLs)	Cost of Oil $	Coal Displaced (tons)	Cost Of Coal ($/ton)	Cost of Coal $
9	DeSoto	2,353	0	12,692	0	0	10	56	0	4,597
10	Space Coast	1,700	0	9,167	0	0	7	31	0	2,586
11	Martin	-43,434	0	-234,254	-1	0	-112	-436	0	-35,967
12	Total	-39,381	0	-212,394	-1	0	-95	-349	0	-28,785

Q.
For the Desoto and Space Coast solar photovoltaic facilities (PV facilities), please describe any equipment failures that resulted in a loss of generation from the facility for calendar year 2011. Please include a description of the equipment failure, the duration of the outage, the suspected cause of the failure, a description of how the failure was mitigated, the cost of repairs, and a description of any manufacturer's warranties that would cover the equipment failure as well as the accounting treatment of such warranties.

A.
Desoto
Desoto experienced an underground cable fault between Desoto's main feeder breaker and Sunshine Substation on May 31, 2011 which caused loss of the entire 25 MW output. Desoto was returned to service on June 10 after the feeder cables were replaced and damaged switchgear equipment repaired. The cause of the cable failure was determined to be a manufacturing defect in which a splice was inadvertently left in the cable to connect two reels of raw conductor together prior to application of insulation material. The splice was not intended to remain and should have been cut out prior to shipment.

The cost to replace the failed cables and repair the damaged switchgear was approximately $100,000. Initially the cable failure was thought to be caused by improper installation of the cable during construction. As such, the repairs were performed by the project's Engineering and Construction contractor, SunPower, under warranty. However, after detailed examination of the failed cable by the cable manufacturer, Prysmian, it was determined that the splice was the primary cause of the failure. The cable was no longer under warranty; however, FPL successfully negotiated with Prysmian to cover the costs of the repair. Prysmian issued a check to FPL for $100,000 of which $90,000 was used to cover the costs that SunPower inccurred for the repair. The remaining $10,000 was used to offset Desoto's O&M cost FPL incurred for materials and supplies used for the repairs.

Space Coast
In 2011 there were no equipment failures that resulted in a loss of generation from the facility.

Q.
For the PV facilities, please provide any information relating to the levels of electromagnetic interference that may be emitted from the facilities and the impact on local transmission and distribution facilities.

A.
The photovoltaic sites were designed to be compliant to the Institute of Electrical and Electronics Engineers (IEEE) industry standard 1547, which includes requirements to ensure any electromagnetic interference (EMI) source does not interfere with the surrounding distribution or transmission facilities. As of March 2012, FPL has not performed any EMI testing at the photovoltaic sites.

Q.
For the PV facilities, please provide any information relating to the levels of harmonic distortion that may be imposed by the facilities and the impact on local transmission and distribution facilities.

A.
The photovoltaic sites are designed and tested for compliance to the Institute of Electrical and Electronics Engineers (IEEE) industry standard 519 for harmonic control in power generation. In addition, the harmonic output of the photovoltaic sites is monitored by protective instrumentation at each site to ensure no effects on the transmission system. The photovoltaic sites are connected to the transmission system via the local substation, so there would be no impact on distribution facilities.

Q.
Regarding the outage at the Martin solar facility that occurred on 06/01/11, FPL stated that "Martin Solar experienced a high pressure excursion on the Heat Transfer Fluid (HTF) system which lifted a safety relief valve on an overflow vessel. This caused a release of the HTF in the form of a vapor plume which condensed on the Martin Solar power block and south side of Martin Unit 8. The high pressure excursion was the result of a leak in the feedwater preheaters." (See response to IROG 71 in Docket No. 110007-EI) For this outage, please provide the following:

a. a one-line diagram showing the interrelation between the HTF and the feedwater preheaters and an indication of where the leak occurred,

b. a description of what caused the leak in the feedwater preheater system,

c. a description of when this component of the feedwater preheater was installed, and last maintained,

d. an estimate of the cost of repair and improvements and how these costs will be recovered.

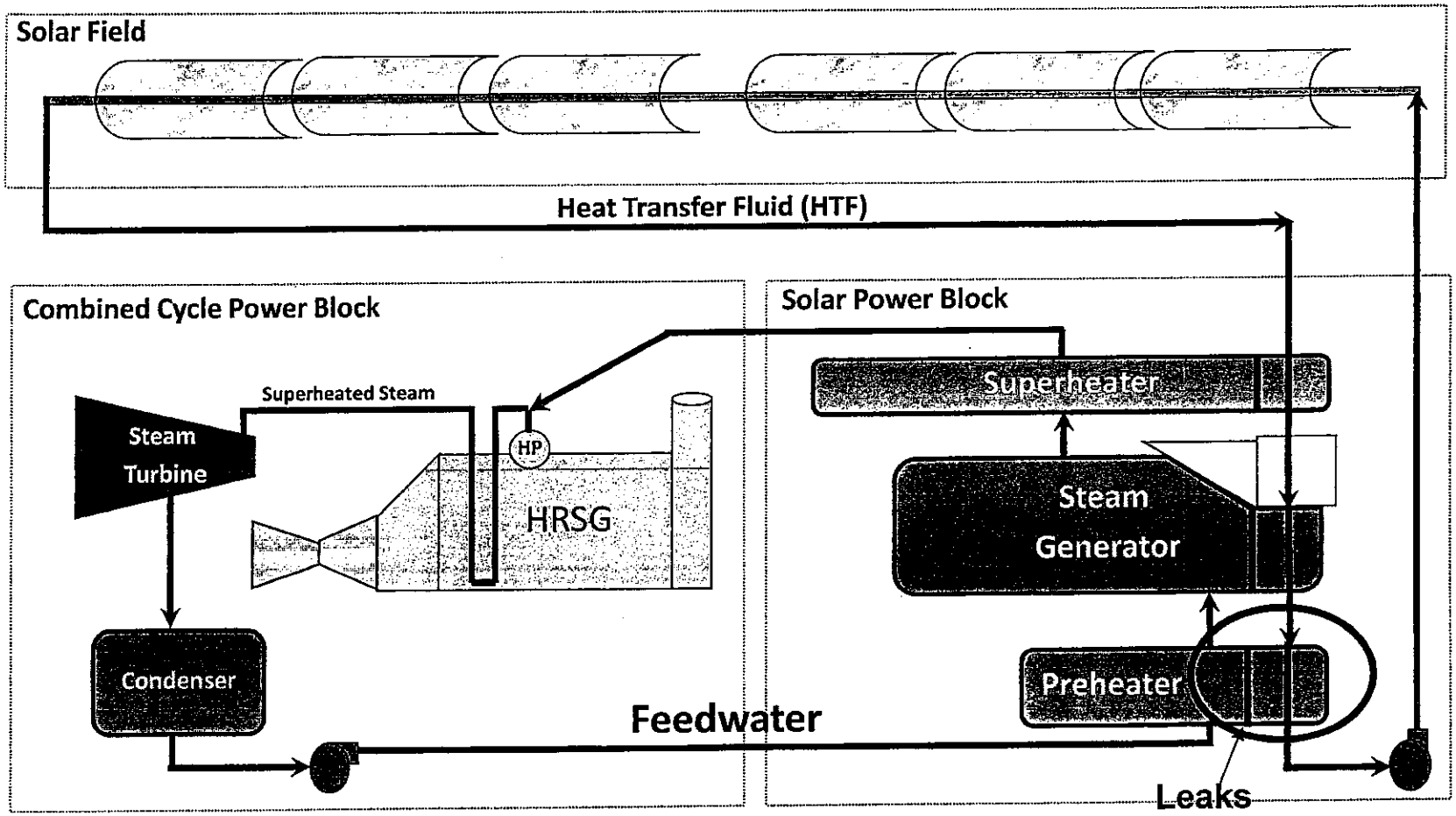
A.
a. See attachment I

b. The leaks in the preheaters were caused by cyclical stresses in the tubesheet faces during daily start-up and cloud cover events which resulted in the welds on the tube to tubesheet joints cracking. In turn, this allowed the higher pressure feedwater to leak into the lower pressure heat transfer fluid side of the preheaters. The mechanical joint was not optimum to handle the cyclical stresses.

c. The preheaters were installed as part of original plant construction. In April of 2011, prior to the HTF release event, maintenance was performed on all four preheaters to repair cracks in the tubesheets. After, the HTF release event, all tubesheet welds were removed and stronger welds were made as a corrective action to prevent further leaks.

d. The cost to repair the feedwater pre-heaters was $251,110 in 2011. These repairs costs are part of the 2011 ECRC O&M true-up filing.

MSEC – Solar Thermal Process Overview



Solar Thermal Hybrid Plant

ECRC Staff 2nd Set Interrogatories Question 20 Section a.

Florida Power & Light Company
Docket No. 120007-EI
Staff's Amended Second Set of Interrogatories
Question No. 20, Attachment 1, Page 1

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Q.
Regarding the outage at the Desoto solar facility that occurred on 05/31/11 involving an underground cable failure, FPL stated that "the cause of the failure was determine to be a manufacturing defect in which a splice was inadvertently left in the cable to connect two reels of raw conductor together prior to application of insulation material." (see IROG 71 in Docket No. 110007-EI). For this outage, please provide the following:

a. how the company verified that the cable met FPL quality standards when purchased and received,

b. a description as to why a splice would cause a cable to fail,

c. a description of what would have been done different if the splice was identified prior to installation,

d. the cost of the repair including any costs for environmental mitigation requirements and how these costs will be recovered, and

e. a description of what action FPL is pursuing in terms of replacement cost or damages from the cable manufacturer.

A.
a. When FPL purchased the cable, the manufacturer was given cable specifications that were in compliance with national electrical standards and FPL specific requirements. After the cable was installed, FPL re-performed insulation resistance tests prior to energization which is standard practice. None of the tests identified the splice in the cable. The cable vendor also performed their standard tests prior to shipping the cable to FPL. These tests include resistance measurements and insulation resistance test (i.e. megger and hi-pot). The splice was made of steel and would have a higher resistance but since it was a very short section, it would not show up as a significant increase in resistance. The insulation resistance tests check for degraded cable insulation which would not be a problem caused by having a cable splice.

b. The mechanical steel splice was not designed to carry current for an extended period of time. The splice created a very short section of cable with high resistance which causes a hot spot from the current flow through the splice. The overheated cable section

eventually caused the cable insulation to fail which caused a ground fault and arc flash in the underground conduit.

c. If the splice was identified prior to installation, it would have not been installed and new cable without any splices would have been used.

d. As stated in the response to question 17, the cost to replace the cable and repair the switchgear was approximately $100,000 and there were no environmental mitigation costs. The repair costs of approximately $100,000 were recovered from Prysmian the cable manufacturer.

e. FPL successfully negotiated with the cable manufacturer, Prysmian, to pay for the costs.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 16th day of April, 2012, 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 answers to interrogatory numbers 9, 10 and 17 through 21 from STAFF'S AMENDED SECOND SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 9-21) in Docket No. 120007-EI, and that the responses are 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 16th day of April, 2012.

Notary Public State of Florida
Jessica Alexander Johnson
My Commission EE108855
Expires 03/02/2015

Notary Public
State of Florida, at Large

My Commission Expires:

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 16th day of April, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan Enjamio, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 11 and 16 from STAFF'S AMENDED SECOND SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 9-21) in Docket No. 120007-EI, and that the responses are true and correct based on his personal knowledge.

Juan Enjamio

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of April, 2012.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lily A Rodriguez
My Commission DD854399
Expires 02/13/2013

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 16th day of April, 2012, 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 12 and 15 and co-sponsored interrogatory numbers 13 and 14 from STAFF'S AMENDED SECOND SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 9-21) in Docket No. 120007-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 16th day of April, 2012.

Notary Public
State of Florida, at Large

MARITZA MIRANDA-WISE
MY COMMISSION # DD 870958
EXPIRES: May 30, 2013
Bonded Thru Notary Public Underwriters

My Commission Expires:
5/30/2013

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 16th day of April, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he co-sponsored the answers to interrogatory numbers 13 and 14 from STAFF'S AMENDED SECOND SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 9-21) in Docket No. 120007-EI, and that the responses are true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of April, 2012.

Lois M Sivia
Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission EE130697
Expires 11/05/2015

3

FPL's Response to Staff's 3rd Set of Interrogatories (Nos. 22-37)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	Docket No: 120007-EI Date: May 30, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S THIRD SET OF INTERROGATORIES (NOS. 22-37)

Florida Power & Light Company ("FPL"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-12-0060-PCO-EI, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff") Third Set of Interrogatories (Nos. 22-37).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the documents, if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these responses provide all of the information that FPL obtained after a reasonable and diligent search

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conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is duplicative not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as unduly burdensome and purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the

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Florida Public Service Commission in this docket. To require any non-regulated entities to participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses.

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II. Responses

Attached hereto are FPL's non-confidential answers to Interrogatory Nos. 22 through 37 of Staff's Third Set of Interrogatories, consistent with its objections, together with the affidavits of the persons providing the answers. Confidential portions of FPL's answers to Staff's Interrogatory Nos. 30 and 34 are being separately filed with a request for confidential classification.

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John T. Butler, Esq.
Assistant General Counsel-Regulatory
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By: _____
Maria Jose Moncada
Fla. Bar No. 0773301

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CERTIFICATE OF SERVICE
Docket No. 120007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail and United States Mail on this 30th day of May 2012 to the following:

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By: _____
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Q.
Please refer to witness T. Keith's testimony and exhibits filed April 2, 2012, for questions 22 – 28.

Please refer to line 17 on page 11 through line 5 on page 12 for the following questions.

(a) Please break down the amount of $15,249 or 49.9% O&M cost variance according to the major component activities.

(b) When, how many times, and in which plant(s) were the emergency diversion schedules (EDS) discussed on line 20 of page 11 triggered during 2011?

(c) What unit(s) does the cooling pond discussed at line 23 of page 11 through line 5 of page 12, serve?

(d) Did FPL perform the data collection discussed on lines 3 – 5 of page 12, or did it retain a contractor to perform the service?

(e) How many times have the EDS been triggered during the past 25 years?

A.
a) 60% ($9,150) of the variance was due to data gathering and evaluation and 40% ($6,099) was due to generating the required report.
b) The emergency diversion schedule was triggered once in 2011. It was for the Manatee plant and covered the period from July 5 through September 7, 2011.
c) The cooling pond serves as make up water for Manatee Plant Units 1, 2 and 3.
d) Data collection, validation, evaluation and report generation were performed by a contractor.
e) The EDS has been triggered four times:

May 28, 2006 thru July 28, 2006
June 14, 2007 thru July 28, 2008
Feb 16, 2009 thru June 19, 2009
July 5, 2011 thru September 6, 2011

Q.
Please refer to witness T. Keith's testimony and exhibits filed April 2, 2012, for questions 22 – 28.
Referring to page 13, lines 11 – 16:

(a) What is the typical life of an RO membrane according to the manufacturer?

(b) Has the supplier ever informed FPL of the life of the RO membranes, such as by stating the life on the product's packaging, or specifying the life in a contract?

(c) Why does FPL believe it is correct to deem the useful life of an RO membrane to be 4 years (lines 15 – 16)? Has FPL conducted any studies to determine how FPL's experience compares to the industry norm? If so, what were the results of these studies? If no, why did PL believe there was no need to conduct any such studies?

A.
(a) According to the manufacturer of the RO membrane (Applied Membranes) in their "Water Treatment Guide", a 5 year life is normally used for economic analysis.

(b) No. According to the manufacturers "Water Treatment Guide," membrane life is a function of feed water source, pretreatment, frequency of cleaning, system design, and operating conditions.

(c1) FPL based the end of life for the RO membranes on actual operating data. FPL also understands that membrane life is a function of feed water source, pretreatment, frequency of cleaning, system design, and operating conditions. Based on our industry survey, FPL believes 4 years is in line with the water quality in our area. According to the supplier of the FPL system a 5 year life is normally used for membrane economic analysis.

(c2) Yes. FPL surveyed independent contractors using similar systems and found they were also getting similar results. FPL contacted G E Power & Water and MPW Industrial Services Inc. MPW Industrial Services Inc reported a system similar to our small membrane system; using similar raw water; would typically get 3 years of life on the membranes. GE Power reported to use a double pass system which gets about 1 year from the membranes in the first pass and extended life on its membranes in the second pass. Our (FPL) system is a single pass system and the experiences of G E Power & Water and MPW Industrial Services Inc have shown similar results.

Q.
Please refer to witness T. Keith's testimony and exhibits filed April 2, 2012, for questions 22 – 28.

Referring to page 13, lines 21 – 23, has FPL filled the vacant position? If yes, when did it happen? If not, why not? Does FPL plan to fill the position? Is it necessary for the position to be filled?

A.
Yes, the position was filled. December 31, 2011 was start date.

Q.
Please refer to witness T. Keith's testimony and exhibits filed April 2, 2012, for questions 22 – 28.

Referring to page 14, lines 11 – 14:

(a) What is the "additional system monitoring instrumentation" to be installed?

(b) What purpose will the instrumentation serve?

(c) What are the costs associated with this addition?

A.
a) The additional instrumentation consists of current transformers and analog input modules associated with our Supervisory Control and Data Acquisition (SCADA) system.

b) The instrumentation provides remote monitoring of the DC input currents into the inverters. This information allows FPL to monitor the performance and degradation of the inverters and PV modules on a continuous basis. The additional instrumentation will improve FPL's ability to quickly detect and respond to equipment problems which helps us maintain a high level of performance with low O&M costs.

c) The cost associated with the instrumentation is approximately $2000 for each inverter. There are 24 inverters at Space Coast which makes the total cost to instrument all inverters approximately $48,000.

Q.
Please refer to witness T. Keith's testimony and exhibits filed April 2, 2012, for questions 22 – 28.

Referring to page 15, lines 14 – 22:

(a) Please break down the amount of $17,518 or 208.9% O&M cost variance according to the major component activities.

(b) Please explain in detail why FPL believes that "control of mercury emission from oil fired power plants would not be required as the EPA developed emission specifications under the Air Toxics rule?"

(c) Please describe the possible impacts on FPL's future compliance activities and their associated costs, assuming that the EPA agrees with FPL's identification/findings?

A.
a. The referenced project expenditures were related to two tasks conducted by toxicologist Edward Zillioux who provided data and comments submitted to the NESHAP rule docket by FPL. These comments resulted in a revision to monitoring requirements in the final rule that will reduce the cost and risk of future monitoring of mercury emissions from FPL's oil-fired facilities. Task one was the requirement to provide quality control review of sampling and analysis protocols for mercury utilized by the contractors and lab assigned to manage the ICR samples. In fact this QA process identified a major flaw in the data provided for one mercury sampling event requiring the contractor to re-sample. The second task was the compilation of current and previously sampled and analyzed mercury emissions data from FPL oil-fired units. This data supported FPL's assertion that oil-fired electric generation emits only de minimus amounts of mercury in comparison to coal-fired generation. Based on the ICR data and additional data analysis FPL submitted comments to EPA suggesting alternative monitoring procedures for mercury emissions from oil-fired generation. Convinced by the extremely low emissions data submitted, EPA's final rule established alternative PM 2.5 (fine particulate) or total HAPs metals (with mercury) analytical options in lieu of previously proposed options that required separate mercury analysis. These options save significant time by eliminating the separate mercury sampling and reduces the costs by $3,000 per unit per quarter.

b. As FPL prepared comments to EPA regarding the emission of mercury from oil-fired fossil steam units, a consultant was retained to evaluate the state of science regarding mercury emissions from oil-fired steam electric generating units and emission data collected by FPL.

Stack emissions data from FPL's oil-fired units were collected in response to the EPA Information Collection Request issued in December 2009. A thorough review of data identified that the health risk of mercury emissions from oil-fired steam electric generating units was below the EPA level of concern. FPL provided test results and data to EPA during the rule comment period to be reviewed prior to promulgation of a final rule for the control of Hazardous Air Pollutants (HAPs) from coal- and oil-fired steam electric generating units under the Maximum Achievable Control Technology (MACT) standards. In its final Mercury and Air Toxics Standards (MATS) Rule, EPA provided oil-fired units the compliance option of meeting a total filterable PM standard as a surrogate to all metal HAPs, instead of requiring compliance with a specific mercury standard as it had done for coal-fired units under 40 CFR Part 63 Subpart UUUUU (63.9991).

c. As FPL stated in its proposal for the installation of ESPs on the Martin and Manatee 800 MW units, installation of ESPs will allow FPL to meet the filterable PM limits under MATS for the HAP metals while maintaining fuel diversity by retaining the ability to burn oil at these units. Assuming that EPA's final MATS establishing the HAP emission limits for coal and oil-fired units is upheld by the court, FPL's implementation of controls on its 800 MW oil-fired units, and controls installed on Plant Scherer for the Georgia Multipollutant Rule, will allow these units to comply with the MATS rule. FPL and JEA have begun a review of the emission data and projected operation of the SJRPP units to identify whether additional controls will be needed to comply with the mercury emission standards under MATS. FPL is unaware of any future compliance requirements at this time that will require other changes to operation on any specific generating unit but is aware that EPA could establish future environmental requirements that could impact its operating costs to comply with air, water, and waste standards.

Q.
Please refer to witness T. Keith's testimony and exhibits filed April 2, 2012, for questions 22 – 28.

Referring to page 16, lines 1 – 5, please explain what caused the contractor payroll costs to be lower than projected.

A.
The 2011 cost estimates were based on conceptual estimates. Actual costs came in lower than those conceptual estimates.

Q.
Please refer to witness T. Keith's testimony and exhibits filed April 2, 2012, for questions 22 – 28.

Referring to page 17, lines 10 – 17:

(a) Please identify each of the emission controls on Scherer Unit 4 to which the testimony refers.

(b) For each of the emission controls identified in (a), please provide a pinpoint citation to each legal authority requiring FPL to install the emission control and explain how the requirement applies.

(c) What will be the total capital costs associated with the construction and installation of the emission controls identified in (a)?

(d) What will be the annual O&M costs associated with running these controls?

(e) What kind of emission controls have been installed on Scherer Unit 3? Are they the same kind of controls as are being installed on Scherer Unit 4?

A.

(a) Wet Flue Gas Desulfurization System (FGD) and Selective Catalytic Reduction System (SCR).

(b) The environmental requirements for the emission controls installed on Plant Scherer Unit 4 are as follows:

1. Baghouse/Sorbant Injection System for control of mercury emissions: Installation of controls was initially proposed to comply with the EPA Clean Air Mercury Rule (CAMR), 40 CFR Part 60 Subpart HHHH (60.4101). Subsequent to proposal of CAMR, the Georgia Environmental Protection Division (EPD) proposed and finalized a Georgia Multi-Pollutant Rule under Chapter 391-3-1 (sss). Rule sss requires installation of controls on specific Georgia coal-fired electric generating units including Scherer Unit 4. Installation of mercury controls was required by EPD (sss 4.) no later than April 30, 2010. While the CAMR cap-and-trade program was vacated by the Court of Appeals for the DC Circuit in February 2008, EPA has subsequently proposed and finalized the Mercury and Air Toxics Standards (MATS) under 40 CFR 63 Supbart UUUUU (63.9980). MATS specifications for coal-fired units requires

mercury emission reductions which FPL believes that would be met by controls installed on Scherer Unit 4.

2. Selective Catalytic Reduction (SCR) System for control of NOx emissions: Installation of SCR was proposed for compliance with the EPA Clean Air Interstate Rule NOx annual cap-and-trade program under 40 CFR 96 Subpart AA (96.102). Subsequent to promulgation of the final CAIR, the Georgia Environmental Protection Division (EPD) proposed and finalized a Georgia Multi-Pollutant Rule under Chapter 391-3-1 (sss). Installation of NOx controls on Scherer Unit 4 are required under rule sss (4.) no later than December 31, 2012. On December 23, 2008 the DC Circuit remanded CAIR without vacature for EPA to promulgate a replacement rule but left CAIR in place until a rule could be finalized. EPA promulgated a final replacement rule, the Cross State Air Pollution Rule (CSAPR), on July 6, 2011 which was stayed by the Court on December 28, 2011 leaving CAIR in place until the court decides on the merits of the petitions.

3. Flue Gas Desulfurization (FGD) System for control of SO2 emissions: Installation of FGD was proposed for compliance with the EPA Clean Air Interstate Rule SO2 annual cap-and-trade program under 40 CFR 96 Subpart BB (96.202). As discussed above, subsequent to final CAIR the Georgia Environmental Protection Division (EPD) proposed and finalized a Georgia Multi-Pollutant Rule under Chapter 391-3-1 (sss). Installation of SO2 controls on Scherer Unit 4 are required under rule sss (4.) no later than December 31, 2012. Additionally, acid gas emission specifications of the National Hazardous Air Pollutant Emission Standards final EPA MATS rule require reductions of SO2 emissions to a level no greater than 0.2lb/mmBtu which is achieved on Scherer Unit 4 through the installation of FGD.

(c) Capital costs are: FGD - $221.1m and SCR - $142.8m.

(d) O&M costs are: FGD - $4.5m and SCR - $1.1m

(e) Scherer Unit 3 has the same emission controls, the FGD and the SCR, as are being installed on Scherer Unit 4.

Q.
For the following questions, please refer to witness R. Kennedy's testimony filed April 2, 2012, regarding the Martin Solar Plant.

(a) Referring to page 4, line 17, what is the cause of the pre-heater needing to be repaired? Was it also caused by the HTF release incident?

(b) Referring to page 4, lines 17 – 18, what is the cause of the unplanned outages at the interconnected Martin Unit 8 combined-cycle plant? Were they also caused by the HTF release incident?

(c) Referring to page 4, lines 17 – 18, what are the O&M costs associated with the (i) pre-heater repairs and (ii) activities performed during the unplanned outages?

(d) Is the difference between the total ECRC 2011 O & M variance $2,319,416 (line 31 on page 2) and the HTF release's remediation cost $2,223,412 (line 20 on page 2), which is $86,004, associated with (i) the pre-heater repairs (line 17 on page 4) and/or (ii) unplanned outages (lines 19-20 on page 4)? Please explain.

(e) What was the cost associated with the emergency response to the HTF release incident?

(f) What was the cost associated with the assessment of the pollution of soil, asphalt, and gravel caused by the HTF release incident?

(g) What was the cost associated with the remediation of the pollution of soil, asphalt, and gravel caused by the HTF release incident?

(h) What was the cost associated with the repair of plant equipment caused by the HTF release incident?

(i) What was the cost associated with the implementation of countermeasures to prevent future incident occurrences?

(j) Referring to page 8, line 4, please break down the $6,733,412 O&M cost amount according to the major component activities of the HTF release incident.

A.

A. The repairs to the feedwater preheaters were necessary due to weld failures on the tube to tubesheet joints. The weld failures were caused by cyclical stresses during daily startups and shutdowns of the system. The cracked welds allowed feedwater to mix with the heat transfer fluid. The mechanical joint was not optimum to handle the cyclical stresses. The Preheater leaks were not caused by the HTF release incident but rather the preheater leaks were a contributing factor to the HTF release incident.

B. Martin Unit 8 experienced an unplanned block outage from 11/25 - 12/19/11 to replace the Hot Reheat and Main Steam isolation valves. This work was necessary to maintain Unit 8 reliability and was in no way influenced by solar operation.

C. The cost associated with the pre-heater repairs totaled $251,110. The activities performed during unplanned outages totaled $70,239 and included labor & parts to repair the Hot Reheat and Main steam isolation valves along with repairs to the solar piping. These costs were not included for recovery through the ECRC.

D. The remaining portion of the variance ($86,004) was not related to pre-heater repairs or activities performed during the unplanned outages of unit 8. The $86,004 variance was related to above normal maintenance repairs (welding of ball joints that allow the mirrors to rotate and the replacement of failed heat transfer fluid tubes). In addition, payroll was added near the end of 2011 to improve the plant operational performance, equipment reliability, and availability.

E. The total cost of the emergency response was $892,500.

F. The total cost associated with the assessment of the pollution of soil, asphalt, and gravel was $408,919.

G. The total cost associated with the remediation of the pollution of soil, asphalt, and gravel was $4,232,047.

H. The total cost associated with the repair of plant equipment caused by the HTF release incident was $1,713,827.

I. The total cost associated with the implementation of countermeasures to prevent future incident occurrences was $378,619.

J. The breakdown consists of assessments, remediation, equipment repairs, and countermeasures as addressed in F through I.

Q.
Please refer to FPL's response to Staff's First Set of Interrogatories, No. 8, for the following questions.

(a) What is the amount of O&M cost that was actually incurred in August 2011?

(b) What is the amount of O&M cost that was actually incurred in December 2011?

(c) Please provide an explanation of the warranty terms of the agreement between FPL and Lauren Engineers & Constructors, Inc. (i) Is there a cap regarding the amount of payment for the first and subsequent incidents? (ii) Is there a cap regarding the of incidents for which the payments will be triggered? (iii) Will the payment be the same for each incident, or will it be reduced for the subsequent incidents?

A.
a. The O&M cost actually incurred in August was $327,518, excluding the impact of transferring the heat transfer fluid release costs ($4,698,083) from ECRC O&M to Base O&M in August 2011.

b. The O&M cost actually incurred in December was $359,890, excluding the ($4,500,000) payment from Lauren Engineers & Constructors, Inc. in December 2011.

c. A copy of the Letter Agreement between FPL and Lauren Engineers & Constructors, Inc. is attached.

(i)– (iii) The Letter Agreement is specific to the release of heat transfer fluid on or about June 1, 2011 (HTF Release Event) at FPL's concentrated solar power parabolic through steam generating facility integrated into the steam cycle of FPL's Martin Unit 8 combined cycle power plant located in Martin County, Florida. The contract for engineering, procurement and construction support with Lauren Engineers & Constructors, Inc. does not contain a warranty provision that expressly addresses the HTF Release Event. The Letter Agreement is made upon the express understanding that it constitutes a negotiated compromised settlement.

Florida Power & Light Company
Docket No. 120007-EI
Staff's Third Set of Interrogatories
Question No. 30
Attachment I, Pages 1 through 4

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Q.
Referring to FPL's response to Staff's Second Set of Interrogatories, No. 10, what was the actual peak energy produced by the Martin Solar that "has exceeded the design output of 75 MW?"

A.
Martin Solar exceeded 75 MWs several times in March with a peak of 88 MWs on 3/26/12.

Q.
Referring to FPL's response to Staff's Second Set of Interrogatories, No. 10, when will FPL be able to make the determination on whether FPL's DeSoto and Space Coast Solar projects can be counted on to reliably contribute firm capacity to FPL's system at the time of system peak?

A.
The benefit of solar continue to reside primarily in the ability to provide a source of renewable energy at essentially no variable cost. FPL continues to collect and analyze the performance data on these two solar projects, but FPL does not have a projected date for when it will be able to determine that solar projects also can reliably contribute firm capacity to its system.

Q.
Please refer to FPL's response to Staff's Second Set of Interrogatories, No. 20, for the following questions.

(a) **In its response to No. 20 (b) FPL stated "[t]he mechanical joint was not optimum to handle the cyclical stresses." Has the mechanical joint been re-designed and replaced ? If not, please explain why not.**

(b) **Is the Cold Reheat steam-path connection discussed in witness Kennedy's testimony filed April 2, 2012 (line 13 on page 6 through line 3 on page 7), part of the improvement to the aforementioned not-optimum mechanical joint design?**

(c) **In its response to No. 20 (c) FPL stated "[i]n April of 2011, prior to the HTF release event, maintenance was performed on all four preheaters to repair cracks in the tubesheets." Is it correct that the problem of tubesheets cracking had occurred and was repaired well before the HTF release incident?**

(d) **Is it correct that the "cracks in the tubesheets" discussed in (c) occurred on the welds, but not the body, of the tubesheets?**

(e) **If the response to (d) is affirmative, did previously found cracks cause any HTF leak or any other detrimental consequence? If so, please provide a detailed explanation of such consequences.**

(f) **If the response to (d) is affirmative, according to FPL's response to No. 20 (c), "[a]fter the HTF release event, all tubesheet welds were removed and stronger welds were made as a corrective action to prevent future leaks." Is it correct that the cracks that caused the June 1 HTF release incident occurred on the welds on which maintenance was just performed in April?**

(g) **If the response to (d) is negative, has any preventive measure been taken to strengthen the tubesheet body?**

A.
(a) Original mechanical joint design had a single seal weld pass on the tube to tube sheet junction, with heavy weld porosity apparent. Final design change incorporated 100% milling of the tube sheet to excavate original weld, and include a new 'J' weld prep chamfer. Tube sheet head was heated to 600F degrees for four hours to bake out any HTF residual in the tube sheet, a process that was not conducted during the original repair in April, 2011. A two pass weld was

also used to create a strength weld design configuration. All tubes were rerolled to a minimum 1% additional wall reduction. NDE testing used throughout each process step to verify integrity.

(b) No, Cold Reheat has nothing to do with weld repair, as it is an optimization of system performance during cloudy conditions.

(c) Yes, the initial attempt to repair tube to tube sheet leaks occurred on all four pre-heaters during a total plant outage in April 2011. Tubes were milled and re-welded to the same seal weld joint configuration. Process incurred difficulty in wicking HTF residual on final weld close, which led to more unidentified weld porosity.

(d) Yes. Pneumatic testing of all tubes revealed no tube leaks. A combination of dye penetrant testing, air and water hydro pressure testing revealed that all leaks were in the tube to tube sheet penetrations.

(e) Yes, the discovery of the presence of water in the HTF lead to the original plant outage to conduct tube leak repairs in April, 2011. Water present in the HTF returning to the expansion vessel will tend to expand in the vapor space generating excessive pressure and large level swings. Sample testing of the HTF verified higher than expected water levels in the fluid.

(f) It is correct that 100% tube sheet weld repair was conducted in April of 2011. NDE liquid dye penetrant surface testing and water hydro verified all leaks were repaired at that time, using the manufacturer's original welding techniques. Several new tube to tube sheet leaks were found after the 6/1/11 release, which led FPL to refine and enhance its welding techniques as described in the response to subpart (a) above.

(g) NA, the response to (d) is positive.

Q.
Please refer to FPL's Supplemental CAIR/CAMR/CAVR Filing of April 2, 2012, for questions 34 - 35:

Under Scherer SCR and Wet Flue Gas Desulfurization (FGD), FPL indicated that Scherer common FGD facility work includes "initial construction activities for FGD gypsum waste disposal facility."

(a) What will be the size (in acres) and capacity (in tons) of the disposal facility?

(b) What are the estimates of the total capital costs and annual O&M expenses associated with this gypsum disposal facility? What are the FPL's shares of these costs?

(c) What is the estimated bill impact ($/1000 kWh) in the ECRC to FPL's customers resulting from the disposal facility?

(d) Is the disposal facility a company-owned landfill, or is it a temporary "working storage" that is used to handle the marketing of the gypsum for beneficial use?

(e) Do the Companies (FPL and Scherer Plant co-owner Southern Company) plan to market the gypsum? If no, please explain why not.

(f) On average, how many tons of gypsum will be produced annually by the FGD which serves Unit 4 at Scherer Plant?

(g) How many years will it take for the disposal facility to reach its ultimate capacity?

(h) What will be the life cycle of the gypsum disposal facility?

(i) Have the Companies conducted any studies on alternative option(s) versus the construction of this disposal facility? If yes, please provide details regarding all the options considered. If no, please explain why FPL believed there was no need to conduct such studies.

(j) Please provide a pinpoint citation to each legal authority requiring the Companies to install the FGD on Unit 4 at Scherer Plant.

(k) What will be the costs to the Companies, as well as their customers, if this gypsum disposal facility is not constructed?

(l) Will the gypsum disposal facility currently under construction satisfy the existing environmental regulation and relevant pending environmental regulations, including the EPA's June 2010 proposed regulation of the management of Coal Combustion Residuals?

(m) When will the Unit 4 FGD be completed and placed in-service?

(n) When will the gypsum facility be completed and placed in-service?

(o) Has Unit 3 at Scherer plant been retrofitted with a FGD?

(p) If the response to (o) is yes, how has the gypsum produced been disposed of?

(q) Is there any gypsum disposal facility currently at the Scherer Plant?

(r) If yes, can the FGD to be installed on Unit 4 share the use of the existing gypsum storage facility after the FGD is placed in-service? If no, please explain why not.

(s) If the response to (o) is yes and the response to (q) is no, will the Companies also use the facility that is currently under-construction to dispose of the gypsum produced by Unit 3 FGD?

A.

(a) Total area site: 350 acres

Total gypsum disposal area: 83.1 acres

Breakdown by gypsum disposal cell:

1. Size in Acres of Coal Combustion By-Product Landfill, by gypsum cell:
   - CELL 1 (CURRENTLY DEVELOPED) 26.0 ac
   - CELL 2 33.8 ac
   - CELL 3 23.3 ac
2. Capacity in tons of Coal Combustion By-Product Landfill, by gypsum cell:
   - CELL 1 (CURRENTLY DEVELOPED) 1,895,000 tn
   - CELL 2 4,087,000 tn
   - CELL 3 1,323,500 tn
3. Years capacity of Coal Combustion By-Product Landfill, by gypsum cell:

CELL 1 (CURRENTLY DEVELOPED)	7 yrs
CELL 2	14 yrs
CELL 3	4 yrs

(b) To date, FP&L's share of the estimated capital costs for the common Plant Scherer gypsum waste storage facility (not including the fiberglass slurry tanks) is $4.22 million of the total estimated facility cost of $21.1 million. FP&L's share of the 2012 estimated costs for operation and maintenance for the common Plant Scherer gypsum waste storage facility is $122,773 of the estimated annual O&M total cost of $160,782 for Scherer Unit 4 .

(c) Based on the estimated total capital costs and annual O&M expenses provided in section (b), the estimated bill impact ($/1,000 kWh) in the ECRC to FPL's residential customers resulting from the disposal facility rounds to less than $0.01.

(d) The facility is a permanent, jointly owned-company landfill. While no gypsum is currently reclaimed from the landfill, reclamation of the gypsum is allowed by the solid waste permit and is a future possibility at the site when economically feasible.

(e) Currently, the supply of FGD gypsum nation-wide is exceeding demand for the product use in the primary market for wallboard manufacturing. There has been a sharply reduced demand for FGD gypsum in wallboard manufacturing because of the severe impacts to new home construction from the economic downturn that began in 2008. FGD gypsum is used to a much lesser extent in agriculture as a soil amendment to add nutrients and to improve soil structure and acidity. At the same time that demand for FGD gypsum has declined, production has increased with installation of controls on additional coal-fired power plants to achieve EPA air quality standards. Because of the over-supply that has resulted from the increased supply and reduced demand, the market price for FGD gypsum has declined substantially. At this time, there are no plans to market the FGD gypsum from Plant Scherer until market prices make it more economical to dewater and transport gypsum for sale than it is to dispose of the gypsum in the on-site landfill. The FGD gypsum in the on-site landfill could be recovered and marketed in the future if market prices recover to the point that it is economically justified to do so. Additional capital expenditures would likely be required to facilitate recovery of the gypsum.

(f) Estimated average annual gypsum production from Unit 4 is [redacted] tons for FPL's ownership share.

(g) For the gypsum waste disposal facility, the number of years to disposal capacity for gypsum varies greatly due to generation at the plant and possible future reclamation of gypsum for beneficial use. Current projections indicate 25 years of disposal capacity for gypsum.

(h) Total life cycle of the landfill (including the gypsum cells) includes initial permitting through a future release from post-closure care. The landfill was permitted on September 4, 2009. Once the entire landfill is at capacity, one year of closure construction, and a minimum 30 years of post-closure care is required.

(i) During Conceptual Design, a mechanical dewatering plant and dry gypsum storage barn were considered; however, it was decided not to market gypsum from Plant Scherer at the time. Space has been reserved in the Plant General Arrangement to add such a facility in the future if required by regulations or if it is decided to market the gypsum from Plant Scherer and such capital investments are cost effective.

(j) The requirement to install a scrubber (FGD) on Plant Scherer Unit 4 is listed in the State of Georgia Rules for Air Quality Control Chapter 391-3-1-.02 (sss) (Multipollutant Control for Electric Utility Steam Generating Units).

(k) Because of the requirements of Georgia's Multipollutant Rule, installation of a scrubber (FGD) on Unit 4 was required. Therefore, it was also necessary to provide a storage and disposal option for gypsum prior to EPA's promulgation of the Mercury and Air Toxics rule. After considering alternative options (see response to (i) above), construction of the gypsum disposal facility was the preferred option. Costs for construction of the landfill could not be avoided unless and until a market for the plant's output of all FGD scrubber byproduct could be developed to ensure long term sale or use from all 4 Scherer Units could be arranged for the estimated remaining life of the plant.

(l) Yes, the gypsum disposal facility is currently permitted as a solid waste landfill by the Georgia Environmental Protection Division. There is much uncertainty surrounding EPA's proposed rule, given that EPA proposed regulation under either Subtitle C or Subtitle D. The gypsum disposal facility generally meets EPA's proposed Subtitle D option, but we recognize that some operational changes may be required to satisfy EPA's final rule.

(m) Unit 4 is scheduled to be ready for initial testing on June 4, 2012. The initial testing is scheduled to be completed on September 4, 2012 with the FGD then being placed into commercial service.

(n) Cell 1 of the gypsum disposal facility was completed on December 21, 2010, and placed in service at that time. Cell 2 and 3 have been permitted and will go in to service after Cell 1 has been filled.

(o) Yes. Plant Scherer Unit 3 is subject to the same requirement as Unit 4 – the requirement to install a scrubber (FGD) on Plant Scherer Unit 3 is listed in the State of Georgia Rules for Air Quality Control Chapter 391-3-1-.02 (sss) (Multipollutant Control for Electric Utility Steam Generating Units). The requirement to operate the Unit 3 FGD was effective on July 1, 2011.

(p) All gypsum generated from the scrubber (FGD) on any unit at Plant Scherer will be stored or disposed in the permitted gypsum cells at the Coal Combustion By-Product Landfill.

(q) Yes, gypsum storage/disposal is currently ongoing at the gypsum disposal facility at the Scherer Plant. Please see question (n).

(r) Yes, All gypsum generated from the scrubber (FGD) on any unit at Plant Scherer will be stored or disposed in the permitted gypsum cells at the Coal Combustion By-Product Landfill.

(s) Not applicable. The response is yes to both **(o)** and **(q)**.

Q.
Please refer to FPL's Supplemental CAIR/CAMR/CAVR Filing of April 2, 2012, for questions 34 - 35:

Please provide the following information with respect to the two FGDs which are currently in operation to serve Units 1 and 2 at St. Johns River Power Park (SJRPP).

(a) When were each of the FGDs placed in-service?

(b) How many tons of gypsum were produced by the FGDs serving Units 1 and 2 at SJRPP for each year that they have been in service?

(c) How did FPL and the units' co-owner JEA dispose of the gypsum?

(d) What are the annual O&M costs (total and FPL's portion) associated with the disposal of the gypsum at the SJRPP?

(e) Is there an on-site gypsum storage facility at the SJRPP?

(f) If the response to (e) is affirmative, what is the size (in acres) and capacity (in tons) of the facility?

(g) If the response to (e) is affirmative, in how many years the facility will reach its limit? What is the designed life of the facility?

(h) Do FPL and/ or JEA own an off-site landfill for gypsum disposal?

(i) If the response to (h) is affirmative, what is the size (in acres) and capacity (in tons) of the facility, and how far is it from the SJRPP?

(j) If the response to (h) is affirmative, in how many years will the facility reach its limit? What is the designed life of the facility?

(k) Do FPL and/ or JEA dispose of gypsum at a third-party landfill(s)?

(l) If the response to (k) is affirmative, what is the tipping fee ($/ton)?

(m) If the response to (k) is affirmative, how far away from the landfill is the SJRPP and what is the transportation cost (ton-mile)?

(n) Do FPL and/ or JEA market the gypsum?

(o) If the response to (n) is affirmative, for each year that it has been marketed, what percentage of the gypsum produced was sold? What were the proceeds from each year's sales? How the proceeds were distributed?

(p) If the response to (n) is negative, please explain why not.

A.
FPL has an ownership share in SJRPP but does not operate the facility. Information regarding the design and operation of the FGD and By-Product disposal have been provided by the SJRPP and JEA.
(a) Unit 1: 12/15/1986; Unit 2: 3/24/1988
(b), (c), (d) Response provided in attached spreadsheet
(e) SJRPP has a permitted on site by-products disposal area which includes gypsum
(f) Total Acreage 286; carrying capacity 37.7 million tons
(g) The SJRPP on site landfill(s) are designed to permanently store 40+ years of by-product materials to include gypsum. However, designed life can be extended or reduced by many variables; types of fuel used to support power generation, ash and sulfur content, market demands of by-products, and by electric generation demand itself.
(h) No
(i) N/A
(j) N/A
(k) No
(l) N/A
(m) N/A
(n) Yes. The FGD scrubbers were part of the original construction at SJRPP and the plant entered into a contract to supply gypsum to a nearby wallboard manufacturer. This close proximity to a buyer, as well as dewatering capabilities that were incorporated into the plant to facilitate processing the gypsum into a marketable form, has made the sale of gypsum economically justified for the plant. While SJRPP continues to sell gypsum to the wallboard manufacturer, the recent downturn in the construction industry has forced SJRPP to accept contract modifications that reduce the volume and price of gypsum that it sells.

(o) Response provided in attached spreadsheet. Gypsum sale revenues come back to the plant and are reflected as an operating expense credit that the two owners then share 50/50 based on ownership share and purchase power agreements.
(p) N/A

SJRPP Synthetic Grade Gypsum - Disposal History

Year	(b) Total Tons Produced (000's)	(c) Tons to On Site Landfill (000's)	(c) Tons Sold (000's)	(d) Landfill $'s O&M Costs ($ 000's)	(d) FPL's O&M Cost ($ 000's)	(o) Gypsum % Sold	(o) Revenue* ($ 000's)
1987							
1988	*Information not readily available*						
1989							
1990	88.4	20.4	68	$71.4	$35.7	76.9%	$311
1991	99.8	1	98.8	$3.5	$1.8	99.0%	$442
1992	81.5	1.2	80.3	$4.2	$2.1	98.5%	$336
1993	104.6	10.7	93.9	$37.5	$18.7	89.8%	$340
1994	102.4	1.9	100.5	$6.7	$3.3	98.1%	$362
1995	115.6	0	115.6	$0.0	$0.0	100.0%	$457
1996	140.5	0	140.5	$0.0	$0.0	100.0%	$548
1997	207.9	54.8	153.1	$191.8	$95.9	73.6%	$616
1998	207.9	54.8	153.1	$191.8	$95.9	73.6%	$616
1999	199.9	21.1	178.8	$73.9	$36.9	89.4%	$803
2000	256.7	15.3	241.4	$53.6	$26.8	94.0%	$1,996
2001	317.8	23	294.8	$80.5	$40.3	92.8%	$2,122
2002	300.9	15.4	285.5	$53.9	$27.0	94.9%	$2,544
2003	230	5	225	$17.5	$8.8	97.8%	$2,358
2004	241.1	0.2	240.9	$0.7	$0.4	99.9%	$2,185
2005	269.4	0.9	268.5	$3.2	$1.6	99.7%	$2,684
2006	202.7	0.2	202.5	$0.7	$0.4	99.9%	$3,067
2007	178.2		178.2	$0.0	$0.0	100.0%	$1,969
2008	91		91	$0.0	$0.0	100.0%	$967
2009	71		71	$0.0	$0.0	100.0%	$657
2010	88.5	0.5	88	$1.8	$0.9	99.4%	$931
2011	132	38	94	$133.0	$66.5	71.2%	$493
Totals	3727.8	264.4	3463.4	$925.4	$462.7	92.9%	$26,804.0

** Gypsum sale revenues come back to the plant and are reflected as an operating expense credit that the two owners then share 50/50 .*

Florida Power & Light Company
Docket 120007-EI
Staff's First Set of Interrogatories
Question No. 35
Attachment I, Page 1 of 1

120007 Hearing Exhibits 00094

Q.

Please provide updates to your response to Staff's First Set of Interrogatory No. 2, in Docket No. 090007-EI, regarding FPL's Generating Facilities and their Air Emission Monitoring & Control Measures. For any emission controls under construction, please report the planed in-service date in column (15).

A.

Update to the spreadsheet has been provided as an attachment.

FPL's Generating Facilities and their Air Emission Monitoring & Control Measures

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						SO2, NOx, Hg, CO2 & Particulate Matter Emission Monitoring			SO2, Nox, Hg, CO2 & Particulate matter Emission Controlling					
Plant Name	Unit No.	Unit Type	Operating Mode	Net Summer Capacity	Commercial In-Service Month/Year	Existing Equipment/ Technology	In Service Date	ECRC Project No.	Existing System/ Technology	In Operation (Yes/No)	System/ Technology Under Construction	In Service Date	ECRC Project No.	Commercial Retirement Month/Year
Cape Canaveral	1	ST	I	396	Apr-65	CEMS (SO2:App D, NOx, CO2)	01/1995	3	MCD	Yes				Jun-10
Cape Canaveral	2	ST	I	396	May-69	CEMS (SO2:App D, NOx, CO2)	01/1995	3	MCD	Yes				Jun-10
Cutler	5	ST	I	68	Nov-54	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB	Yes				Nov-12 (planned)
Cutler	6	ST	I	137	Jul-55	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB	Yes				Nov-12 (planned)
Fort Myers	2	CC	B	1440	Jun-02	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN	Yes				
Fort Myers	3 A & B	CT	P	324	Jun-03	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN, WI	Yes				
Fort Myers	1-12	GT	P	648	May-74	CEMS (NOx: LME)	12/2008	31						
Lauderdale	4	CC	B	436	May-93	CEMS (SO2:App D, NOx, CO2)	01/1995	3	WI	Yes				
Lauderdale	5	CC	B	436	Jun-93	CEMS (SO2:App D, NOx, CO2)	01/1995	3	WI	Yes				
Lauderdale	1-12	GT	P	420	Aug-70	CEMS (NOx: LME)	12/2008	31						
Lauderdale	13-24	GT	P	420	Aug-72	CEMS (NOx: LME)	12/2008	31						
Manatee	1	ST	I	819	Oct-76	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, RBN, MCD	Yes	ESP	RBN: 12/2005; ESP 06/2013	RBN: 24; ESP: 45	
Manatee	2	ST	I	819	Dec-77	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, RBN, MCD	Yes	ESP	RBN: 11/2006; ESP: 06/2012	RBN: 24; ESP: 45	
Manatee	3	CC	B	1104	Jun-05	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN, SCR	Yes				
Martin	1	ST	I	839	Dec-80	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, MCD	Yes	ESP	ESP: 03/2014	ESP: 45	
Martin	2	ST	I	839	Jun-81	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, MCD	Yes	ESP	ESP: 12/2014	ESP: 45	
Martin	3	CC	B	478	Feb-94	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN	Yes				
Martin	4	CC	B	478	Apr-94	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN	Yes				
Martin	8	CC	B	1104	Jun-05	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN, WI, SCR	Yes				
Port Everglades	1	ST	I	220	Jun-60	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, MCD, ESP	Yes		12/1993, 05/2006	LNB: 2, ESP: 25	Jan-13 (planned)
Port Everglades	2	ST	I	220	Apr-61	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, MCD, ESP	Yes		07/1994, 10/2005	LNB: 2, ESP: 25	Jan-13 (planned)
Port Everglades	3	ST	I	387	Jun-64	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, MCD, ESP	Yes		04/1992, 10/2007	LNB: 2, ESP: 25	Jan-13 (planned)
Port Everglades	4	ST	I	387	Apr-65	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, MCD, ESP	Yes		05/1992, 05/2007	LNB: 2, ESP: 25	Jan-13 (planned)
Port Everglades	1-12	GT	P	420	Aug-71	CEMS (NOx: LME)	12/2008	31						
Putnam	1	CC	I	249	Apr-78	CEMS (SO2:App D, NOx, CO2)	01/1995	3						
Putnam	2	CC	I	249	Aug-77	CEMS (SO2:App D, NOx, CO2)	01/1995	3						
Riviera	3	ST	I	277	Jun-62	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB	Yes		11/1994	LNB: 2	Feb-11
Riviera	4	ST	I	288	Mar-63	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB	Yes		05/1994	LNB: 2	Feb-11
Sanford	3	ST	I	138	May-59	CEMS (SO2:App D, NOx, CO2)	01/1995	3						Nov-12 (planned)
Sanford	4	CC	B	958	Oct-03	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN	Yes				
Sanford	5	CC	B	958	Jun-02	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN, WI	Yes				
Scherer	4	ST	B	646	Jul-89	CEMS (SO2:App D, NOx, CO2)	04/2010	33	LNB, SOFA, ESP	Yes	SCR, LSFO, ACI, FF	SCR/FGD: 09/2012, SCI/FF: 04/2010	SCR/FGD:31, ACI/FF:33	
St Johns River Power Park	1	ST	B	125	Mar-87	CEMS (SO2:App D, NOx, CO2, Hg)	06/2008, 12/2009	33, 31	LNB, FGD	Yes	SCR, COB	04/2009	SCR: 31	
St Johns River Power Park	2	ST	B	125	May-88	CEMS (SO2:App D, NOx, CO2, Hg)	06/2008, 12/2009	33, 31	LNB, SCR, FGD	Yes	COB	01/2009	SCR: 31	
St. Lucie	1	NP	B	839	May-76	N/A	01/1995	3						
St. Lucie	2	NP	B	714	Jun-83	N/A	01/1995	3						
Turkey Point	1	ST	I	396	Apr-67	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, MCD	Yes		04/1995	LNB: 2	
Turkey Point	2	ST	I	392	Apr-68	CEMS (SO2:App D, NOx, CO2)	01/1995	3	LNB, MCD	Yes		12/1994	LNB: 2	
Turkey Point	3	NP	B	693	Nov-72	N/A	01/1995	3						
Turkey Point	4	NP	B	693	Jun-73	N/A	01/1995	3						
Turkey Point	5	CC	B	1144	May-07	CEMS (SO2:App D, NOx, CO2)	01/1995	3	DLN, WI, SCR	Yes				
Turkey Point	1-5	IC	P	12	Dec-87									

IC - Internal Combustion
ST - Fossil Steam
CC - Combined Cycle
CT - Combustion Turbine
GT - Gas Turbine
NP - Nuclear Power
PV - Photovoltaic

B - Base Load
I - Intermediate Load
P - Peak Load

LSFO - Limestone Forced Oxidation Scrubber
LSD - Lime Spray Dryer Scrubber
SCR - Selective Catalytic Reduction
SNCR - Selective Non-Catalytic Reduction
RBN - Reburn
SOFA - Separated Overfire Air
LNB - Low NOx Burners
DLN - Dry Low NOx Burners
COX - Catalytic Oxidation
WI - Water Injection
ACI - Activated Carbon Injection Hg Control
COB - Co-Benefits Hg Control
ESP - Electrostatic Precipitator
FF - Fabric Filter Baghouse
MCD - Multi-Cyclone Dust Collector
TOX - Toxecon

Florida Power & Light Company
Docket 120007-EI
Staff's First Set of Interrogatories
Question No. 36
Attachment 1, Page 1 of 1

120007 Hearing Exhibits 00096

Q.
Referring to FPL's three Next Generation Solar Energy centers, please provide updated information on the following questions:

a. What is the total construction cost for each facility?

b. What is the impact on a customer bill of 1000 kWh ($) and 1200 kWh ($)
c. How much energy is being produced by each center?

A.
a. The chart below provides total construction costs (comprised of the sum of Plant In Service and CWIP earning a return) as of April 30, 2012.

Project Description	ECRC Project	Construction Cost
Desoto Next Generation Solar Energy Center	37	$ 152,682,994
Space Coast Next Generation Solar Energy Center	38	$ 70,633,125
Martin Next Generation Solar Energy Center	39	$ 405,249,324

b. The impact on the customer bill has been recalculated to include adjustments in project cost and generated energy as indicated in part "a" and "b" of this question. Attached are revised tables for question #2 of Staff's first set of interrogatory questions reflecting the recalculated bill impact.

c. The chart below shows energy produced (MWh) for each center in 2011 and the first quarter of 2012.

Solar Energy Center	2011 Actuals Net Generation (MWh)	1st Quarter 2012 Actuals Net Generation (MWh)
DESOTO	51,560	12,125
SPACE COAST	18,720	4,696
MARTIN	28,982	17,853
Total	**99,262**	**34,674**

(1) Net Generation data represents a calendar month
(2) MWh data is actuals from monthly Solar Plant Operation Status Report

New Generation DeSoto Solar Project
System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

Year	[1] Annual System Total Revenue Requirements with Solar Project $ Millions	[2] Annual System Total Revenue Requirements without Solar Project $ Millions	[3] Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	[4] Differential in Customer Bill $/ 1000 kWH	[5] Differential in Customer Bill $/ 1200 kWH
2008	0	0	0	0.000	0.000
2009	10	0	10	0.099	0.119
2010	16	0	16	0.155	0.186
2011	15	0	15	0.147	0.177
2012	2,909	2,894	16	0.154	0.184
2013	3,038	3,022	16	0.152	0.183
2014	3,371	3,357	15	0.140	0.168
2015	3,624	3,610	14	0.132	0.159
2016	4,445	4,432	13	0.116	0.139
2017	4,912	4,900	12	0.111	0.133
2018	6,521	6,510	11	0.100	0.120
2019	7,035	7,025	10	0.086	0.103
2020	7,859	7,848	10	0.088	0.106
2021	8,706	8,698	9	0.074	0.088
2022	9,149	9,140	8	0.068	0.081
2023	9,112	9,104	9	0.070	0.084
2024	9,701	9,694	7	0.057	0.069
2025	10,571	10,565	6	0.044	0.053
2026	11,187	11,181	6	0.047	0.056
2027	11,931	11,926	5	0.034	0.041
2028	12,520	12,515	5	0.037	0.044
2029	13,246	13,242	3	0.025	0.030
2030	14,162	14,158	4	0.029	0.035
2031	14,988	14,984	4	0.025	0.030
2032	16,240	16,237	3	0.020	0.025
2033	18,295	18,293	2	0.016	0.020
2034	19,671	19,670	1	0.006	0.007
2035	20,632	20,631	0	0.003	0.003
2036	22,856	22,857	0	-0.002	-0.003
2037	24,311	24,311	0	0.001	0.001
2038	25,525	25,526	0	-0.003	-0.004
2039	27,120	27,122	-2	-0.012	-0.015
2040	28,573	28,578	-4	-0.026	-0.032

Notes:

Negative indicates a reduction in the customer bill for the 25 MW solar project.

The annual revenue requirements include fixed costs (capital, fixed O&M and firm gas transportation costs) for future generation resources, as well as the three existing solar projects. Revenue requirements from existing facilities are not included as they would be the same for both simulations and would not impact the result. Projected variable costs (fuel, VOM, and emission costs) for all of FPL's generation resources, including existing ones are also included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

Next Generation Space Coast Solar Project
System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

Year	[1] Annual System Total Revenue Requirements with Solar Project $ Millions	[2] Annual System Total Revenue Requirements without Solar Project $ Millions	[3] Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	[4] Differential in Customer Bill $/ 1000 kWH	[5] Differential in Customer Bill $/ 1200 kWH
2008	0	0	0	0.000	0.000
2009	1	0	1	0.010	0.012
2010	7	0	7	0.068	0.082
2011	8	0	8	0.074	0.088
2012	2,901	2,894	7	0.071	0.085
2013	3,030	3,022	8	0.080	0.096
2014	3,364	3,357	8	0.074	0.089
2015	3,616	3,610	7	0.061	0.073
2016	4,438	4,432	6	0.058	0.069
2017	4,906	4,900	6	0.055	0.066
2018	6,515	6,510	5	0.042	0.050
2019	7,030	7,025	4	0.039	0.047
2020	7,854	7,848	5	0.045	0.054
2021	8,702	8,698	4	0.035	0.042
2022	9,144	9,140	4	0.031	0.037
2023	9,108	9,104	5	0.037	0.044
2024	9,698	9,694	4	0.034	0.041
2025	10,568	10,565	3	0.024	0.029
2026	11,185	11,181	4	0.029	0.035
2027	11,929	11,926	3	0.019	0.023
2028	12,519	12,515	3	0.024	0.029
2029	13,245	13,242	2	0.015	0.019
2030	14,161	14,158	3	0.021	0.025
2031	14,987	14,984	3	0.019	0.023
2032	16,238	16,237	1	0.010	0.012
2033	18,295	18,293	2	0.014	0.017
2034	19,671	19,670	1	0.006	0.007
2035	20,632	20,631	1	0.005	0.006
2036	22,857	22,857	0	0.002	0.002
2037	24,312	24,311	1	0.007	0.009
2038	25,527	25,526	1	0.005	0.006
2039	27,122	27,122	0	-0.002	-0.002
2040	28,576	28,578	-2	-0.010	-0.012

Notes:

Negative indicates a reduction in the customer bill for the 10 MW solar project.

The annual revenue requirements include fixed costs (capital, fixed O&M and firm gas transportation costs) for future generation resources, as well as the three existing solar projects. Revenue requirements from existing facilities are not included as they would be the same for both simulations and would not impact the result. Projected variable costs (fuel, VOM, and emission costs) for all of FPL's generation resources, including existing ones are also included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

New Generation Martin Solar Project
System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

Year	[1] Annual System Total Revenue Requirements with Solar Project $ Millions	[2] Annual System Total Revenue Requirements without Solar Project $ Millions	[3] Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	[4] Differential in Customer Bill $/ 1000 kWH	[5] Differential in Customer Bill $/ 1200 kWH
2008	0	0	0	0.000	0.000
2009	7	0	7	0.065	0.078
2010	29	0	29	0.276	0.331
2011	50	0	50	0.485	0.582
2012	2,938	2,894	44	0.431	0.517
2013	3,066	3,022	44	0.425	0.510
2014	3,397	3,357	41	0.386	0.464
2015	3,649	3,610	40	0.367	0.440
2016	4,468	4,432	36	0.328	0.394
2017	4,935	4,900	35	0.316	0.380
2018	6,539	6,510	30	0.264	0.317
2019	7,054	7,025	28	0.250	0.300
2020	7,875	7,848	27	0.230	0.276
2021	8,722	8,698	25	0.207	0.249
2022	9,164	9,140	24	0.198	0.237
2023	9,127	9,104	23	0.185	0.222
2024	9,714	9,694	20	0.159	0.190
2025	10,581	10,565	16	0.123	0.148
2026	11,196	11,181	15	0.114	0.136
2027	11,941	11,926	14	0.106	0.127
2028	12,526	12,515	11	0.078	0.093
2029	13,252	13,242	9	0.068	0.082
2030	14,166	14,158	9	0.061	0.073
2031	14,995	14,984	10	0.072	0.087
2032	16,241	16,237	4	0.030	0.036
2033	18,297	18,293	4	0.030	0.036
2034	19,671	19,670	1	0.006	0.008
2035	20,631	20,631	0	-0.001	-0.001
2036	22,856	22,857	-1	-0.006	-0.007
2037	24,307	24,311	-3	-0.021	-0.026
2038	25,521	25,526	-4	-0.028	-0.033
2039	27,115	27,122	-7	-0.041	-0.049
2040	28,569	28,578	-9	-0.054	-0.065

Notes:

Negative indicates a reduction in the customer bill for the 75 MW solar project.

The annual revenue requirements include fixed costs (capital, fixed O&M and firm gas transportation costs) for future generation resources, as well as the three existing solar projects. Revenue requirements from existing facilities are not included as they would be the same for both simulations and would not impact the result. Projected variable costs (fuel, VOM, and emission costs) for all of FPL's generation resources, including existing ones are also included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

These projections are based on simulations using the same assumptions in the Port Everglades Next Generation Clean Energy Center need filing using the midcourse fuel forecast correction. These assumptions will be updated for the 2012 Ten Year Site Plan report.

Recoverable cost quantities in 2008 are too small to show on the table.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 17th day of May, 2012, 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 answers to interrogatory numbers 22 through 25, 28 through 29, 30 a&b, 31, 33 and 37c from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 22-37) in Docket No. 120007-EI, and that the responses are true and correct based on his/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 17th day of May, 2012.

Notary Public
State of Florida, at Large

Notary Public State of Florida
Jessica Alexander Johnson
My Commission EE106855
Expires 03/02/2015

My Commission Expires:

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 29th day of May, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 26, 34a-b & d-s, 35 and 36 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 22-37) in Docket No. 120007-EI, and that the responses are true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29th day of MAY, 2012.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission EE130697
Expires 11/05/2015

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 29 day of May, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Pamela L. Metz, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 27 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 22-37) in Docket No. 120007-EI, and that the responses are true and correct based on her personal knowledge.

Pamela L. Metz

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29 day of May, 2012.

Notary Public
State of Florida, at Large

My Commission Expires:
6/16/14

LIDIA HOFFMAN
MY COMMISSION # DD973149
EXPIRES June 16, 2014
(407) 398-0153 FloridaNotaryService.com

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 29th day of May, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan Enjamio, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory numbers 32 and 37b from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 22-37) in Docket No. 120007-EI, and that the responses are true and correct based on his personal knowledge.

Juan Enjamio

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29th day of May, 2012.

Iwanda S. Jenkins
Notary Public
State of Florida, at Large

My Commission Expires:

NOTARY PUBLIC-STATE OF FLORIDA
Iwanda S. Jenkins
Commission # DD827829
Expires: NOV. 19, 2012
BONDED THRU ATLANTIC BONDING CO., INC.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 29 day of May, 2012, 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 acknowledged before me that he provided the answer to interrogatory number 34c from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 22-37) in Docket No. 120007-EI, and that the responses are true and correct based on his personal knowledge.

Terry J. Keith
Terry J. Keith

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29 day of May, 2012.

Maria R. Arrabal
Notary Public
State of Florida, at Large

My Commission Expires:

MARIA R. ARRABAL
MY COMMISSION # DD 976352
EXPIRES: July 4, 2014
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 24th day of May, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Nelda Jacques, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory numbers 30c and co-sponsored 37a from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 22-37) in Docket No. 120007-EI, and that the responses are true and correct based on her personal knowledge.

Nelda Jacques

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24th day of May, 2012.

Barbara Grenz
Notary Public
State of Florida, at Large

My Commission Expires:

BARBARA GRENZ
MY COMMISSION # DD 971058
EXPIRES: April 22, 2014
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 30th day of May, 2012, 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 co-sponsored the answer to interrogatory 37a from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 22-37) in Docket No. 120007-EI, and that the response is true and correct based on his personal knowledge.

Elizabeth Fuentes

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of May, 2012.

Notary Public
State of Florida, at Large

My Commission Expires:

NOTARY PUBLIC-STATE OF FLORIDA
Iwanda S. Jenkins
Commission # DD827829
Expires: NOV. 19, 2012
BONDED THRU ATLANTIC BONDING CO., INC.

4

FPL's Response to Staff's 4th Set of Interrogatories (Nos. 38-48)

RECEIVED
JUL - 5 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	Docket No: 120007-EI Date: July 2, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FOURTH SET OF INTERROGATORIES (Nos. 38-48) AND fIRST REQUEST FOR PRODUCTION OF DOCUMENTS (No. 1)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-12-0060-PCO-EI, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff") Fourth Set of Interrogatories (Nos. 38-48) and First Request for Production of Documents (No. 1).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the documents, if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these

responses provide all of the information that FPL obtained after a reasonable and diligent search conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is duplicative not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as unduly burdensome and purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to

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lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the Florida Public Service Commission in this docket. To require any non-regulated entities to participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses.

II. Responses

Fourth Set of Interrogatories (Nos. 38-48). Attached hereto are FPL's answers to Interrogatory Nos. 38 through 48 of Staff's Fourth Set of Interrogatories consistent with its objections, together with the affidavits of the persons providing the answers. The affidavit of Tony Biacci, co-sponsor of answers to Interrogatories Nos. 39-48, will be provided at a later date.

First Request for Production of Documents (No. 1). Attached hereto is FPL's response to Staff's First Request for Production of Documents No. 1, consistent with its objections. FPL will provide all responsive documents directly to Staff.

R. Wade Litchfield, Esq.
Vice President and General Counsel
John T. Butler, Esq.
Assistant General Counsel-Regulatory
Maria J. Moncada, Esq.
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Telephone: (561) 304-5795
Facsimile: (561) 691-7135

By: _____
Maria Jose Moncada
Fla. Bar No. 0773301

CERTIFICATE OF SERVICE
Docket No. 120007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail and United States Mail on this 2nd day of July 2012 to the following:

Charles Murphy, Esq.
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Florida Public Service Commission
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By: _____
Maria Jose Moncada
Fla. Bar No. 0773301

Q. Please refer to "Deferred Gain on Sales of Emission Allowances," pages 51 – 52 of Form 42-8A of witness T. J. Keith's Exhibit TJK-1 filed April 2, 2012, and the corresponding Excel worksheets "DefGain_P1," "DefGain_P2," and "Allowance Auction Proceeds," contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls" for the following questions.

a. Referring to worksheets "DefGain_P1" and "DefGain_P2," please explain how the figures shown in each of the cells F62 through K62, were derived, and specify the formulas that were used for the calculations.

b. Please explain how each of the cells J62 and K62, in worksheet "DefGain_P1" is linked to the cells E10 through E16, in worksheet "Allowance Auction Proceeds."

a.
The amounts in each of the cells F62 through K62 reflect the Balance Sheet balance for account 254.900, *Deferred Gain on Sale of Emission Allowances*. The change in balance is derived by:

1. Proceeds received from the sale of current vintage year (VY) 2011 emissions allowances and from the sale of 7-year out VY 2018 emissions allowances. For example, FPL received proceeds in 2011 from the sale of both VY 2011 and VY 2018 emissions allowances.

2. Amortization of the gain is comprised of the following: 1.) the gain from the sale of the vintage year 2011 emissions allowances sold in 2011 and 2.) the gain from the VY 2011 emissions allowances sold 7 years prior in 2004. FPL amortized these gains ratably through 2011.

3. Gains realized from the sale of prior vintage years sold at market in the current year (2011).

Example:

Beginning Period:(12/1/11) Amount of "Cell J62" of worksheet "DefGain_P2"	(1,819,592)
LESS: Current month (Dec) amortization amount of the gain realized from the sale Of VY 2011 emission allowances (cell D24) in "Allowance Auction Proceeds"	21,897
Ending balance: Amount of "Cell K62" of worksheet "DefGain_P2"	(1,797,695)

b.

Beginning Period: (5/1/11) Amount of "Cell I62" of worksheet "DefGain_P1"	(1,968,764)
ADD: Proceeds received from the sale of VY 2011 emission allowances (sum of cells E10 + E11) in "Allowance Auction Proceeds."	(4,979)
ADD: Proceeds received from the sale of VY 2018 emission allowances (sum of cells E13 + E14) in "Allowance Auction Proceeds."	(299)
LESS: Current month (May) amortization amount of the gain realized from the sale Of VY 2011 emission allowances (cell D9) in "Allowance Auction Proceeds"	23,500
Ending balance: Amount of "Cell J62" of worksheet "DefGain_P1"	(1,950,542)

Beginning Period: (6/1/11) Amount of "Cell J62" of worksheet "DefGain_P1"	(1,950,542)
ADD: Proceeds received from the sale of VY 2011 emission allowances "Cell E12") in "Allowance Auction Proceeds."	(660)
ADD: Proceeds received from the sale of VY 2018 emission allowances "Cell E15") in "Allowance Auction Proceeds."	(40)
ADD: Proceeds received from the sale of VY 2009 emission allowances "Cell E16") in "Allowance Auction Proceeds."	(16,750)
LESS: Current month (June) amortization amount of the gain realized from the sale of VY 2011 emission allowances (cell D18) in "Allowance Auction Proceeds"	22,171
LESS: Gain realized from the sale of VY 2009 emission allowances sold at market (cell D17) in "Allowance Auction Proceeds"	16,750
Ending balance: Amount of "Cell K62" of worksheet "DefGain_P1"	(1,929,071)

Q.

This question pertains to project No. 5b "Maintenance of Above Ground Storage Tanks," page 7, of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheet "StorTks_P1" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls." Referring to column K (June) on row 66 (account CI78005 – Plant Additions) in worksheet "StorTks_P1," please describe the rationale for the accounting entry of negative $7,176.

A.

The $7,176.00 negative addition in the schedule was a reversal from General Ledger (GL) Account 106.1 – Plant In Service Under Review. These dollars were found to be removal costs (GL 108.300) which were recorded to base. This reversal was associated with fuel oil storage tank (FOST) instrumentation replacement at Ft. Myers GTs in plant account 342.0 (WO G00000006768).

When assets are in GL 106.1, they can be moved in or out of the account only by using the FERC activity code (e.g., additions) that was used when they went into 106.1. Depending on the amount of the transaction in comparison to the total monthly activity (including GL 101.0 activity) at the location, plant account, and subaccount (clause type / base) a total net negative addition can sometimes result. Negative additions can occur particularly when assets are in GL 106.1 and may be due to re-estimates, differences between accruals and actual billing, accounting corrections, re-evaluations upon unitization, etc.

Q.

This question pertains to project No. 20 "Waste water/Stormwater Reuse," page 17 of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheet "Wastewater_P1" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls." Referring to columns I (April) and K (June) on row 66 (account CI98020 – Plant Additions) in worksheet "Wastewater_P1," please describe the rationale for the accounting entries of negative $233,855.58 and negative $244.86.

A.

The April 2011 negative addition of $233,855.58 in the schedule was a reversal from General Ledger (GL) Account 106.1 – Plant In Service Under Review. These dollars were found to be removal costs (GL 108.300) which were recorded to base. The June 2011 negative addition of ($244.86) was a reversal of additions while in GL Account 106.1. Both of these reversals were associated with a basin liner replacement at Pt Everglades Common in plant account 311.0 (WO G00000016032).

Q.

This question pertains to project No. 23 "Spill Prevention," page 24 of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheet "Spill Prevent_P2" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls." Referring to column H (September) on row 66 (account CI78023 – Plant Additions) in worksheet "Spill Prevent_P2," please describe the rationale for the accounting entry of negative $3,036.84.

A.

The $3,036.84 negative addition in Sep 2011 was a reversal from General Ledger (GL) 106.1 – Plant In Service Under Review. These dollars were found to be cost of removal associated with fuel oil tank level monitoring system replacement at Putnam Common in plant account 342.0 (WO G00000024692). The dollars were reclassified to removal costs and are shown on worksheet "Spill Prevent_P2" on column H, row 71.

Q.
Please refer to project No. 26 "UST Removal/ Replacement," page 30 of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheet "RUST_P2" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls" for the following questions.

a. Referring to column F (July) on row RUST_P2 on row 73 (account CIC8026 Reserve Trans& Adjs), please describe the rationale for the accounting entry of $345,900.79.

b. Referring to the activity recorded in cell F73 discussed in (a), please explain why there was no corresponding plant transfer (i.e. no accounting entry to column F on row 67 account CI98026) when there was a reserve transfer in the month of July.

A.
The explanations are as follows:

a. When FPL's General Office (GO) building was sold, the sale included $377,469.73 of underground storage tank assets. At the time of the sale in April 2011, only $31,568.94 had been recorded to the accumulated provision for depreciation for these assets. When the sale occurred the retirement was debited to the clause, but the other recovery needed to bring the net book value of the UST assets at the GO Building to zero ($345,900.79) was inadvertently credited to base. This credit to base was subsequently reversed with a debit to base and an offsetting credit to the reserve in the clause as shown in the reserve transfer in Cell F73 on RUST_P2 (July 2011).

b. Because there was no plant in service impact of this transaction, there was no corresponding plant transfer needed or recorded in the clause.

Q.

Please refer to project No. 31 "CAIR Compliance," pages 31 – 32 of Form 42-8A of Exhibit TJK-1 and their corresponding Excel worksheets "CAIR_P1" and "CAIR_P2," contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls" for the following questions.

a. Please describe the rationale for the accounting entry for each of the following cells: G67 through K67 in worksheet "CAIR_P1" regarding account CI9 8031 - Plant Trans and Adjs.

b. Referring to columns I (April), J (May), and K (June) on rows 67 (account CI9 8031 - Plant Trans and Adjs) and row 73 (account CIC8031 - Reserve Trans and Adjs) in worksheet "CAIR_P1," please explain why there were no corresponding reserve transfers when plant transfers and adjustments incurred in the months of April, May and June, respectively.

c. Referring to column H (March) on row 66 (account CI78031 - Plant Additions) in worksheet "CAIR_P1," please describe the rationale for the accounting entry of negative $52,880,634.40.

A.

a.

The February 2011 plant transfer of $411,775.23 shown in cell reference G67 of "CAIR_P1", is a reclassification of base assets determined to be CAIR clause related that were in distribution Account 365 in Martin County (Work Order D00003707221). The $222,604.47 plant transfer that occurred in March 2011 ("CAIR_P1", cell reference H67) was related to the N2 blanket system at Manatee Unit 1 and was a reclassification from base to clause.

The April 2011 through June 2011 plant transfers were reclassifications of assets back from base to clause (credit base, debit clause) primarily related to work orders for the NOx Reduction Project at SJRPP Units 1 & 2. The associated assets, originally placed in service in 2009 as 100% recoverable through ECRC Project 31, were moved to base through a negative addition (credit clause, debit base) of $53,412,173.99 in March 2011 (see part c of this response). During the review process, as the amounts were determined to be properly included in the clause, these assets were transferred back into clause Project 31. The amounts shown in cell

references I67 through K67 of "CAIR_P1" represent corrections of plant costs from base to clause for the following:

April, 2011: The $38,019,223.96 amount represents the reclassifications of SJRPP Units 1 & 2 costs, primarily NOx reduction and improvement costs.

May, 2011: The $15,395,819.72 amount represents the reclassifications of SJRPP Units 1& 2 NOx Reductions.

June, 2011: The ($2,869.68) amount represents a ($34,868.69) correction of a reclassification that occurred in May 2011 and a transfer of $31,999.01 for Work Order G00000000518 associated with the re-classification of SJRPP Unit 1 associated with NOx reduction system assets

b. When the plant in service associated with the SJRPP Unit 1 & 2 NOx reduction work orders (mentioned in part a and c of this interrogatory response) was moved during the unitization process as negative additions (credit clause, debit base) in March 2011, no reserve was transferred. FPL's accounting record system (PowerPlant), does not generate automated reserve transfers for negative additions. When the associated plant in service dollars were transferred back into the clause in April 2011, May 2011, and June 2011, PowerPlant automatically calculated and recorded reserve transfers debiting the accumulated provision for depreciation for base and crediting the accumulated provision for depreciation for the clause. Since the reserves for base and the clause were not impacted in the March 2011 negative additions, the reserves should not have been impacted by the April through May 2011 plant transfers back to clause. To prevent the reserve transfers from incorrectly affecting the clause during April, May, and June , manual journal vouchers crediting the reserve for base and debiting the reserve for clause for $1,571,306.30, $341,054.45, and $3,665.46, respectively, were processed to offset the automated PowerPlant reserve transfers.

c. In March 2011, there were $53,412,173.99 of negative additions related to the clause for the SJRPP Units 1& 2 NOx Reduction work orders (described in the part a), partially offset by normal additions of $531,539.59, resulting in a net negative addition of $52,880,634.40 (cell reference H66 of "CAIR_P1").

Q.

This question pertains to project No. 33 "CAMR Compliance," page 24 of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheet "CAMR_P1" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls." Referring to columns F (January) and K (June) on row 66 (account CI78033 – Plant Additions) in worksheet "CAMR_P1," please describe the rationale for the accounting entries of negative $21,691.04 and $320,134.82.

A.

The negative addition in January 2011 was associated with reversals of accruals in GL 106.1 – Plant In Service Under Review. The January 2011 reversals were ($122,401.00) while the new additions were $100,709.96. The negative addition in June 2011 was due to a transfer back to inventory for ($468,611.23) offset by new charges of $148,476.41. The reason that the net additions were negative in January 2011 was that the reversal of the accruals for contractor bills exceeded the actual bills received, while the reason for June's net negative additions was a credit addition to reduce plant in service for a spare induced draft fan reclassified to Materials & Supplies (M&S) which exceeded the other additions recorded for the month. In both months, these entries were associated with baghouse additions at Scherer Unit 4 in plant account 312.0 (WO G00000000505).

Q.

This question pertains to project No. 36 "Low Level Rad Waste-LLW," page 38 of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheet "LL Rad Waste_P2" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls." Referring to columns G (August) and K (December) on row 66 (account CI78036 – Plant Additions) in worksheet "LL Rad Waste_P2," please describe the rationale for the accounting entries of negative $10,316.26 and negative $153,425.80, respectively.

A.

The total August 2011 addition of ($10,316.26) resulted from a reversal of vendor accruals of $326,843.63 which exceeded actual additions for the month of $316,527.37. The total ($153,425.80) addition in December 2011 was also related to vendor accruals. In December, the reversal of $241,663.41 related to vendor accruals that exceeded the actual additions for the month of $88,237.61. Both of these reversals were associated with the low-level radioactive waste storage facility at St Lucie Common in plant account 321.0 (WO P00000001048).

Q.

This question pertains to project No. 37 "Desoto Next Generation Solar Energy Center," page 40 of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheet "Solar-Desoto_P2" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls." Referring to column J (December) on row 65 (account CI78037 – Plant Additions) in worksheet "Solar-Desoto_P2," please describe the rationale for the accounting entry of negative $88,367.61.

A.

The negative addition shown in **November 2011** (the Interrogatory mentions December, but the cell reference and amount indicated is actually from November) consists of the following plant additions:

Work Order	Plant Account	GL Account	Location	Amount
P00000005797	341	101	DeSoto Solar	985.39
T00000001747	352	106.1	Manatee Plant Switchyard	(816.01)
T00000001747	353	106.1	Manatee Plant Switchyard	(88,536.99)
			Manatee Total	(89,353.00)
			Grand Total	(88,367.61)

The total monthly negative additions of $88,367.61 are primarily associated with the unitization of the $816.01 in Account 352.0 and $88,536.99 for Account 353.0, both at the Manatee Plant Switchyard. These entries total to a negative addition of $89,353.00, which is offset by a net positive addition of $985.39 for DeSoto Solar.

During a re-estimate of the work order, the Manatee Plant Switchyard was inadvertently changed from clause to base and as a result, the charges transferred and were unitized in base, resulting in the credit of $89,353 in 106.1 in the clause. Upon further review, these dollars should have remained in the clause and will be transferred back during 2012.

Q.
Please refer to project No. 41 "Manatee Temporary Heating System," page 45 - 46 of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheets "PRV Manatee_P1" and "PRV Manatee_P2" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls" for the following questions.

a. Referring to column K (June) on row 66 (account CI78041 – Plant Additions) in worksheet "PRV Manatee_P1," please describe the rationale for the accounting entry of negative $3,024.70.

b. Referring to columns F (July) and K (December) on row 66 (account CI78041 – Plant Additions) in worksheet "PRV Manatee_P2," please describe the rationale for the accounting entries of negative $6,013.01 and $1,299.68.

A.
a. The negative addition shown in June 2011 consists of the following plant additions:

Work Order	Plant Account	General Ledger Account	Location	Amount
G00000002554	314	106.1	Cape Canaveral Common	($0.07)
T00000002650	362	106.1	Tulsa Substation - Feeder	($2,317.02)
T00000002650	397.2	106.1	Tulsa Substation - Feeder	($707.61)
			Total	($3,024.70)

These negative additions were caused by a reversal of equipment in General Ledger (GL) 106.1 back to storeroom.

b. The negative addition shown in July 2011 consists of the following plant additions:

Work Order	Plant Account	General Ledger Account	Location	Amount
T00000002356	353	106.1	Riviera Plant Switchyard	($283,596.40)
T00000002356	353	101	Riviera Plant Switchyard	$276,703.86
G00000002554	314	106.1	Cape Canaveral Common	$879.53
			Total	($6,013.01)

During the work order review process, there was $6,892.54 more GL 106.1 additions reversed than unitized to GL 101.0 and resulted in the total negative addition for the month.

The negative addition shown in December 2011 consists of the following negative plant additions:

Work Order	Plant Account	General Ledger Account	Location	Amount
G00000002554	314	106.1	Cape Canaveral Common	($0.04)
G00000356705	314	106.1	Cape Canaveral Common	($25.47)
T00000002356	353	106.1	Riviera Plant Switchyard	($264.40)
T00000002949	362	106.1	Riviera Plant Switchyard	($1,009.77)
			Total	($1,299.68)

These negative plant additions are reversals of additions while in GL 106.1.

When assets are in GL 106.1, they can be moved in or out of the account only by using the FERC activity code (e.g., additions) that was used when they went into 106.1. Depending on the amount of the transaction in comparison to the total monthly activity (including GL 101.0 activity) at the location, plant account, and subaccount (clause type / base) a total net negative addition can sometimes result. Negative additions can occur particularly when assets are in GL 106.1 and may be due to re-estimates, differences between accruals and actual billing, accounting corrections, re-evaluations upon unitization, etc.

Q. This question pertains to project No. 42 "PTN Cooling Canal monitoring System," page 47 of Form 42-8A of Exhibit TJK-1 and its corresponding Excel worksheet "PTN Cooling Canal_P1" contained in the Company-provided Excel file "Form 42-8A Pgs 1-52 Final.xls." Referring to columns H (March) and I (April) on row 66 (account CI78042 – Plant Additions) in worksheet "PTN Cooling Canal_P1," please describe the rationale for the accounting entries of negative $117,517.72 and negative $11,363.58.

A.

The total monthly addition of ($117,517.72) in March 2011 is related to a reclassification from clause to O&M for ($112,872.21) with credits in payroll and journal vouchers of ($4,216.45) and ($429.06), respectively. The April 2011 total negative addition of ($11,363.58) is due to a miscellaneous receivable for a vendor overbilling of ($12,828.56) which exceeded the total other charges for the month $1,464.98. The transactions in both months are associated with cooling canal monitoring at Turkey Pt Common in plant account 321.0 (WO P00000021866).

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 28th day of June, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Scott Bores, who is personally known to me, and he acknowledged before me that he co-sponsored the answers to interrogatory numbers 39 through 48 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 38-48) in Docket No(s). 120007-EI, and that the responses are true and correct based on his personal knowledge.

Scott Bores

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28 day of June, 2012.

Notary Public
State of Florida, at Large

My Commission Expires:
2/26/2016

NICOLE ANDREA GREGORY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# EE173212
Expires 2/26/2016

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 29 day of June, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jennifer Grant-Keene, 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 AND LIGHT COMPANY (NOS. 38-48) in Docket No(s). 120007-EI, and that the response is true and correct based on her personal knowledge.

Jennifer Grant-Keene

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29 day of June, 2012.

NICOLE ANDREA GREGORY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# EE173212
Expires 2/26/2016

Notary Public
State of Florida, at Large

My Commission Expires:
2/26/2016

5

FPL's Response to Staff's 5th Set of Interrogatories (Nos. 49-52)

RECEIVED
AUG 29 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause

Docket No: 120007-EI
Date: August 29, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIFTH SET OF INTERROGATORIES (Nos. 49-52)

Florida Power & Light Company ("FPL"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-12-0060-PCO-EI, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff") Fifth Set of Interrogatories (Nos. 49-52).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the documents, if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these responses provide all of the information that FPL obtained after a reasonable and diligent search

conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is duplicative not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as unduly burdensome and purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the

120007 Hearing Exhibits 00132

Florida Public Service Commission in this docket. To require any non-regulated entities to participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses.

120007 Hearing Exhibits 00133

II. Responses

Fifth Set of Interrogatories (Nos. 49-52). Attached hereto are FPL's answers to Interrogatory Nos. 49 through 52 of Staff's Fifth Set of Interrogatories, consistent with its objections and together with the affidavits of the persons providing the answers.

Respectfully submitted this 29th day of August, 2012

R. Wade Litchfield, Esq.
Vice President and General Counsel
John T. Butler, Esq.
Assistant General Counsel-Regulatory
Maria J. Moncada, Esq.
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Telephone: (561) 304-5795
Facsimile: (561) 691-7135

By: _____
Maria José Moncada
Fla. Bar No. 0773301

CERTIFICATE OF SERVICE
Docket No. 120007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Objections and Responses to the Staff of the Florida Public Service Commission's Fifth Set of Interrogatories (Nos. 49-52) has been furnished by electronic mail and United States Mail on this 29th day of August 2012 to the following:

Charles Murphy, Esq.
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By: _____
Maria Jose Moncada
Fla. Bar No. 0773301

Q.
Please refer to FPL's Preliminary List of New Projects for Cost Recovery (List) filed July 10, 2012, for the following questions.

Referring to Thermal Discharge Standards Project on the List:
a. Please provide the specific legal citation of the "EPA's more stringent 316(a) variance guidance."

b. When does FPL expect to receive the decisions from the EPA Region 4 and the FDEP regarding its proposed POS?

c. Has FPL started the baseline sampling for the Riviera plant site as what it's doing for the Cape Canaveral plant?

d. Please provide a breakdown of the component activities that comprise the estimated $175,000 of 2012 O&M costs, together with the associated affected plants.

e. Please provide a breakdown of the component activities that comprise the estimated $175,000 of 2013 O&M costs, together with the associated affected plants.

f. What will be the estimated O&M costs to implement the POS for the Canaveral and Riviera plants if the EPA Region 4 and the FDEP approve the Company's proposed approach of using the publicly available information?

A.
a. Prior 316 (a) variance renewals for PCC, which were justified by biological studies conducted in the early 1980's, only required the facility to request the renewal as part of the IWWF renewal application and to confirm that there have been no significant changes to the thermal output of the facility. While FPL followed this practice with the latest renewal, EPA has requested substantial additional assessment. A review of recent EPA internal memoranda suggests that this shift to a more stringent 316(a) variance renewal procedure was likely triggered by several EPA actions between 2008 and 2011, including:

- A 2008 EPA Memorandum stated a need to clarify the procedures and criteria for granting and renewing CWA Section 316(a) thermal variances based on 2007 Permit Quality Reviews by EPA's Office of Wastewater Management. EPA's 2008 Memorandum also identified the need to:

"...provide a framework for reviewing permit application materials that summarizes existing requirements to ensure consistency with section 316(a) of the CWA and its implementing regulations".

For variance renewals, the memorandum stated that:

"...it is essential that permitting authorities require applicants to provide as much of the information described in 40 C.F.R. § 125.72(a) and (b) *as necessary* to demonstrate that the alternative effluent limit assures the protection and propagation of the BIP [Balanced Indigenous Population]... Such information *may* include a description of any changes in facility operations, the waterbody, or the BIP since the time the variance was originally granted." [emphases added]

- EPA's Office of Inspector General (OIG) reviewed North Carolina and Region 4 implementation of §316(a) variances between 2010 and 2011 and found "procedural lapses" in permit renewal development and documentation. These findings were summarized in a May 9, 2011 Memorandum from OIG that instructed EPA's Region 4 Administrator to "Verify that thermal variances are protective of a balanced, indigenous population".

- EPA Region 4 submitted correspondence to FDEP on January 11, 2011 regarding the 316 (a) variance renewal at PCC. In that correspondence, EPA Region 4 states, "EPA recognizes that, under 40 Code of Federal Regulations (C.F.R.) § 125.73(c), existing sources seeking variance renewal are not typically required to conduct the same detailed, comprehensive studies required under §§ 125.72(a) and (b). Also, under § 125.73, existing sources can base their demonstration on a lack of appreciable harm instead of completing predictive studies. However, under § 125.72(c), the type of detailed studies contemplated under §§ 125.72(a) and (b) can be required whenever determined to be necessary. After examining the record of prior 316(a) variance determinations for the Cape Canaveral Plant, EPA has concerns regarding the need for a more thorough examination and definition of the Balanced and Indigenous Population (BIP), the identification of Representative Important Species (RISs), and a closer examination of whether the variance is protective. Given the thinness of the available record to justify prior variance determinations, EPA believes a more focused study is needed. EPA acknowledges that Florida Power and Light (FP&L) has in the past collected a substantial amount of data in support of its variance. FP&L may use existing data in completing its study and may incorporate the existence of such data into the study plan design; however, the existing data needs to be evaluated and presented in the context of a BIP definition that the existing record does not adequately provide."

In addition, subsequent conversations and correspondence with EPA Region 4 and FDEP, as well as projects undertaken by other facilities in Region 4 that have recently renewed their 316 (a) variances, have made it very clear that some expanded justification for the variance renewal will be required.

b. FPL has been corresponding with FDEP and EPA Region 4 and expects to have an approved POS by early 2013 as FPL intends to begin any required post-operational studies soon after commercial operation of PCC which is scheduled for June 2013.

c. No

d.

PCC	**2012**	
Task	Description	Cost
Task 1	Draft Plan of Study	$25,000
Task 2	Baseline Sampling	$50,000
	Total	**$75,000**
PRV	**2012**	
Task		Cost
Task 1.1	Review Available Information/Data Gap Analysis/Modeling	$45,000
Task 1.2	Draft Schedule and Meetings with FDEP	$30,000
Task 1.3	Draft and Final POS	$25,000
	Total	**$100,000**
Note:	Costs are estimated based upon conceptual thermal Plans of Study developed by FPL. Agency review and approval may alter the scopes of work and thus overall cost for implementation of the Plans.	

e.

PCC	**2013**	
Task	Description	Cost
Task 1	Complete Plan of Study	$25,000
Task 2	Baseline Sampling	$100,000
	Total	**$125,000**
PRV	**2013**	
Task		Cost
Task 1.1	Baseline Sampling	$50,000
	Total	**$50,000**
Note:	Costs are estimated based upon conceptual thermal Plans of Study developed by FPL. Agency review and approval may alter the scopes of work and thus overall cost for implementation of the Plans.	

f.

Total estimated costs for 2012 and 2013, assuming that the current PCC Plan of Study was accepted as currently submitted and only required sampling (baseline PCC sampling) to be conducted, would be approximately $50,000 for PCC based on an assumed reduction in monitoring scope. If FDEP agrees that baseline sampling is not necessary at PRV, the anticipated savings will be the $50,000 estimated for that task in 2013.

Q.

Please refer to FPL's Preliminary List of New Projects for Cost Recovery (List) filed July 10, 2012, for the following questions.

Referring to Power Plant Gopher Tortoise Relocations Project of the List:

a. Please provide the specific legal citation of the Florida Fish and Wildlife Conservation Commission's new guidelines regarding the gopher tortoise relocation.

b. Please provide a breakdown of the component activities that comprise the estimated $37,500 of 2012 O&M costs.

c. Will the costs associated with the periodic surveys be recovered through the ECRC or base rates?

A.

a. The Gopher tortoise (*Gopherus polyphemus*) is a state-designated threatened species, per Rule 68A-27.003(2)(d)3, Designation of Endangered Species; Prohibitions, which states: "The Gopher tortoise shall be afforded the protective provisions specified in this subparagraph. No person shall take, attempt to take, pursue, hunt, harass, capture, possess, sell or transport any gopher tortoise or parts thereof or their eggs, or molest, damage, or destroy gopher tortoise burrows, except as authorized by Commission permit or when complying with Commission approved guidelines for specific actions which may impact gopher tortoises and their burrows. A gopher tortoise burrow is a tunnel with a cross-section that closely approximates the shape of a gopher tortoise. Permits will be issued based upon whether issuance would further management plan goals and objectives."

b. In order to receive a permit for gopher tortoise relocation, an authorized gopher tortoise agent must conduct a survey of the area in question. Once they confirm that the burrow is that of a gopher tortoise, they can apply for the FWC Conservation Permit online. Once the permit is received, the tortoises may be captured via bucket traps, live traps, hand capture outside of burrow or excavation by hand shovel or backhoe. However, excavation can only be used if it will not compromise the integrity of the embankment. After the tortoise is captured, it will be taken to an offsite, long-term, protected recipient site.

Associated costs include survey by authorized gopher tortoise agent, consultant fees for compiling permit application and capturing tortoise (via bucket trap, live traps, hand captures or excavation) and relocating to recipient site, mitigation contribution to FWC, and recipient site fees. At this time, a conservative estimate per tortoise needing relocated is $2500, which results in a total of $37,500 for an estimated 15 tortoises.

c. Periodic surveys, which are part of normal plant maintenance activities and conducted by FPL plant personnel, will be recovered through base rates.

Q.
Please refer to FPL's Preliminary List of New Projects for Cost Recovery (List) filed July 10, 2012, for the following questions.

Referring to Steam Electric Effluent Guidelines Revised Rules Project of the List:

a. Please provide a breakdown of the component items that comprise the $50,000 in O&M expenditures.

b. Has FPL retained the consultant(s) to provide the services?

c. If the response to question (b) is affirmative, please identify each of the contractors that has been retained, and the services that each contractor will provide.

A.
a.

Task	Description	Year Incurred	Cost
Task 1	Sampling of oil ash contact and metal cleaning effluent streams	2012	$5,000
Task 2	Development of comments on draft revised Steam Effluent Guidelines Rule	2013	45,000
		Total	**$50,000**

b. No.

c. N/A

Q.
Please refer to FPL's Preliminary List of New Projects for Cost Recovery (List) filed July 10, 2012, for the following questions.

Referring to Florida Numeric Nutrient Criteria Project of the List:
a. Will the estimated $1.6 million of O&M and $1.2 million of capital costs for the budget years 2013 through 2017 be associated only with Martin plant's compliance?

b. If the response to (a) is negative, please provide a breakdown of the component activities that comprise the estimated $1.6 million of O&M costs by year, and by the associated affected plant.

c. If the response to (a) is negative, please provide a breakdown of the component activities that comprise the estimated $1.2 million of capital costs by year, and by the associated affected plant.

d. Please provide a breakdown of the component items that comprise the $0.442 million in O&M expenditures for 2013.

e. Will the compliance activities listed in the third paragraph on page 8 be performed by FPL's in-house resource?

f. If the response for question (e) is negative, will FPL be soliciting bids?

g. If the response to question (a) is affirmative, please provide the estimated O&M and capital compliance costs for the Manatee, Sanford, Putnam, and Ft. Myers plants.

A.
a. The estimated O&M and capital costs for budget years 2013 through 2017 are associated with the FPL power generation facilities that have intake and outfall structures within and adjacent to freshwaters which are also Waters of the State. Those power generation facilities are Ft. Myers, Manatee, Martin, Putnam, and Sanford.

b. Ft. Myers Plant:	2013	2014	2015	2016	2017
Monthly Sampling for TN/TP	$48,600	$46,200	$46,200	$46,200	$46,200
Biological Assessment	$12,000	$12,000	$12,000	$12,000	$12,000
Change Water Chemistry				$20,000	$20,000

Manatee Plant:	2013	2014	2015	2016	2017
Monthly Sampling for TN/TP		$48,600	$46,200	$46,200	$46,200
Biological Assessment		$12,000	$12,000	$12,000	$12,000

Martin Plant:	2013	2014	2015	2016	2017
Monthly Sampling for TN/TP	$48,600	$46,200	$46,200	$46,200	$46,200
Biological Assessment	$12,000	$12,000	$12,000	$12,000	

Putnam Plant:	2013	2014	2015	2016	2017
Monthly Sampling for TN/TP	$48,600	$46,200	$46,200	$46,200	$46,200
Biological Assessment	$12,000	$12,000	$12,000		
Change Water Chemistry	$100,000	$20,000			

Sanford Plant:	2013	2014	2015	2016	2017
Monthly Sampling for TN/TP	$48,600	$46,200	$46,200	$46,200	$46,200
Biological Assessment	$12,000	$12,000	$12,000	$12,000	
Change Water Chemistry	$100,000	$20,000			

c. Martin Plant: Year 2015; Change water flow structures to modify the treatment system and nutrient removal processes $1,000,000

Martin Plant: Year 2016; Change water flow structures to modify the treatment system and nutrient removal processes $200,000

d. Ft. Myers Plant: Monthly Sampling, Testing, Reporting for TN/TP - $48,600
Biological Health Assessment - $12,000

Martin Plant: Monthly Sampling, Testing, Reporting for TN/TP - $48,600
Biological Health Assessment - $12,000

Putnam Plant: Monthly Sampling, Testing, Reporting for TN/TP - $48,600
Biological Health Assessment - $12,000
Change Water Chemistry - $100,000

Sanford Plant: Monthly Sampling, Testing, Reporting for TN/TP - $48,600
Biological Health Assessment - $12,000
Change Water Chemistry - $100,000

e. The water sampling at the intake and outfall structures for total nitrogen and total phosphorus, laboratory testing, summary reports and the Stream Condition Index/Shannon-Weaver Index biological health assessments upstream and downstream of the discharge structures will be conducted by private contractors.

f. Yes, FPL will extend a request for proposals to conduct the water sampling, testing, and summary reporting and biological health assessment activities.

g. The response to question (a) is negative.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 23rd day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jodie Gless, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 50 from STAFF'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 49-52) in Docket No. 120007-EI, and that the response is true and correct based on her personal knowledge.

Jodie Gless

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23rd day of August, 2012.

Notary Public State of Florida
Lois M Sivia
My Commission EE130697
Expires 11/05/2015

Lois M Sivia
Notary Public
State of Florida, at Large

My Commission Expires:
11/5/15

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 22nd day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ronald H. Hix, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 49 and 51 from STAFF'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 49-52) in Docket No. 120007-EI, and that the responses are true and correct based on his personal knowledge.

Ronald H. Hix

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22nd day of August, 2012.

Notary Public State of Florida
Lois M Silvia
My Commission EE130697
Expires 11/05/2015

Notary Public
State of Florida, at Large

My Commission Expires:
11/5/15

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 22nd day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Eric Shea, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 52 from STAFF'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 49-52) in Docket No. 120007-EI, and that the response is true and correct based on his personal knowledge.

Eric Shea

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22nd day of August, 2012.

Notary Public State of Florida
Lois M Sivia
My Commission EE130897
Expires 11/05/2015

Lois M Sivia
Notary Public
State of Florida, at Large

My Commission Expires:
11/5/15

6

FPL's Response to Staff's 6th Set of Interrogatories (Nos. 53-56)

RECEIVED
SEP 18 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause

Docket No: 120007-EI
Date: September 13, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S SIXTH SET OF INTERROGATORIES (Nos. 53-56)

Florida Power & Light Company ("FPL"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-12-0060-PCO-EI, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff") Sixth Set of Interrogatories (Nos. 53-56).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the documents, if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these responses provide all of the information that FPL obtained after a reasonable and diligent search

conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is duplicative not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as unduly burdensome and purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the

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Florida Public Service Commission in this docket. To require any non-regulated entities to participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses.

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II. Responses

Sixth Set of Interrogatories (Nos. 53-56). Attached hereto are FPL's answers to Interrogatory Nos. 53 through 56 of Staff's Sixth Set of Interrogatories, consistent with its objections and together with the affidavits of the persons providing the answers.

Respectfully submitted this 13th day of September, 2012

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By: _____
Maria Jose Moncada
Fla. Bar No. 0773301

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CERTIFICATE OF SERVICE
Docket No. 120007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Objections and Responses to the Staff of the Florida Public Service Commission's Sixth Set of Interrogatories (Nos. 53-56) has been furnished by electronic mail and United States Mail on this 13th day of September 2012 to the following:

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By: _____
María José Moncada
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Q. Please refer to page 11, lines 4 – 20, of witness Keith's testimony filed August 1, 2012.

a. Please identify the 5-factors of the BART determinations referenced at lines 15-16.

b. When will the required determinations and modeling be completed?

c. Has FPL retained the consultants to provide the services referenced at lines 18 – 20?

d. Will FPL potentially need to implement further compliance activity based on the outcome of the visibility modeling? If so, what will be the time frame to bring the affected plant into compliance?

A.

a. To determine what is the Best Available Retrofit Technology (BART) for a BART-eligible source, the State must consider the following 5-factors: 1) The cost of compliance; 2) The energy and non-air quality environmental impacts of compliance; 3) Any existing pollution control technology in use at the source; 4) The remaining useful life of the source, and; 5) The degree of visibility improvement which may reasonably be anticipated from the use of BART.

b. The modeling and required determinations have been completed and were incorporated into the State's revised Regional Haze State Implementation Plan (SIP) recently submitted to the EPA.

c. Yes. Golder & Associates were retained by FPL for the preparation of the 5-factor analysis.

d. FPL believes that its 5-factor analysis adequately demonstrates that the planned implementation of BART at its eligible facilities meets the federal and state requirements. We anticipate that EPA will approve Florida's Regional Haze SIP and do not believe FPL will have to implement further activity to comply with the BART requirements.

Q. Please refer to line 21 on page 11 – line 1 on page 14 of witness Keith's testimony regarding FPL's Next Generation Solar Energy Centers.

a. Please identify the number of full-time and part-time positions at each of the three Solar Centers.
b. What are the daily water consumption rates (portable and reclaimed water, respectively) used for washing the mirrors at the Martin Solar Energy Center?
c. Please provide detailed information regarding the "preheater leak" referenced at line 23 of page 13. When did it occur, and when were the repairs completed?
d. Please elaborate on the "[a]dditional preheater leak" referenced at line 24 of page 13 and provide information regarding any incident(s) of prior preheater leak(s).
e. Please provide a line diagram of Martin Solar identifying key components of the preheater leaks discussed in witness Keith's testimony.
f. How did the preheater leak discussed in witness Keith's testimony affect operation of Martin Solar?
g. What was the cause of the preheater leak discussed in witness Keith's testimony?
h. What steps has FPL taken to prevent future preheater leaks?

A.
a. **Desoto Solar Site -** 4 Full Time (FT) employee, no Part Time employees. **Kennedy (PKS) / Space Coast (PSC)** - zero - all FT employees are now assigned to the Desoto site and support & charge PKS/PSC on an as needed basis. No Part Time employees. Technical Services Fleet - 1 FT position. This position is used to support all 3 solar sites on an as needed basis. The employee direct charges which site he/she is supporting.
Martin Solar Site - There are 15 full time employees and no part time employees.

b. The average amount per day demineralized water use is 6500 gals.

c. & d. After approximately two months in service, all trains were determined to be leaking with C train largest contributor to water contamination of the four trains. The C train was taken out of service in June 2012, for a three week outage. Testing verified the source of water in-leakage was the pre-heater. Leaks were found to originate in the tube to tube sheet joints. Eleven out of a possible 780 tube joints were identified to have some level of defect and were repaired.

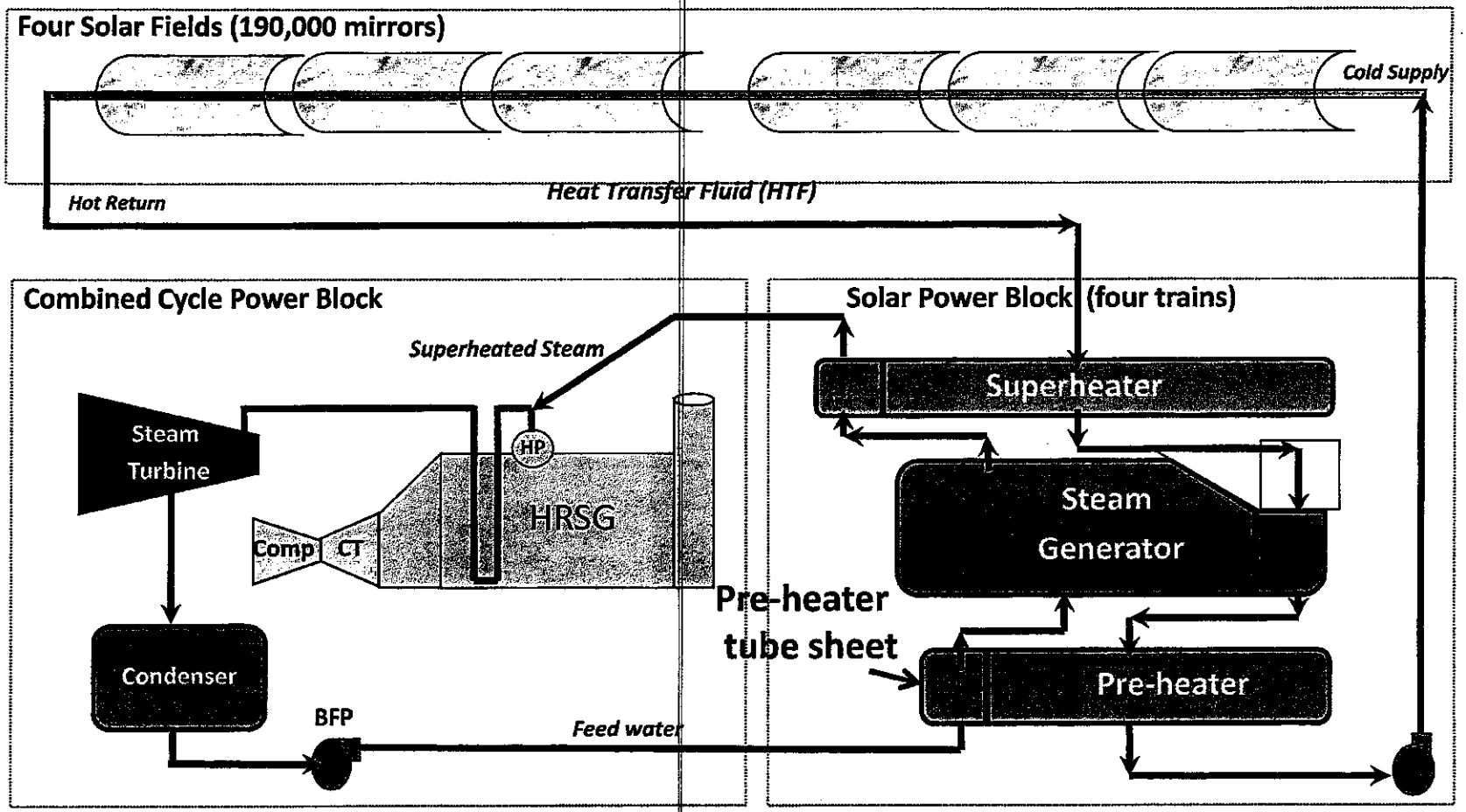
e. See Attachment I. Note: Document is representative of 1 solar power block train. There are a total of 4.

f. Pre-heater tube sheet leaks allowed water intrusion into the heat transfer fluid resulting in expansion vessel pressure transients. To perform repairs, the solar block train had to be taken out of service.

g. Cyclical stresses in the tube sheet faces during daily start-up and cloud events caused the welds on the tube-to-tube sheet joints to crack, which in turn resulted in higher pressure feed water leaks into the low pressure heat transfer fluid side of the heat exchangers. The mechanical joint was not designed to handle the cyclic stress discovered in this new technology.

h. Thermal transients have been minimized through process control changes. Repair methodology was improved by adding tube sheet bake out to eliminate any HTF residual between the tubes & tube sheet responsible for previous weld porosity. We currently are evaluating overall heat exchanger design for improvement opportunities.

MSEC – Solar Thermal Process Overview



Heat transfer fluid is heated to generate steam which produces an additional 75 MW's out of the Unit 8 ST.

Florida Power & Light Company
Docket 120007-EI
Staff's Sixth Set of Interrogatories
Question No. 54
Attachment 1, Page 1 of 1

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Q. Please refer to page 17 of witness Labauve's testimony filed August 1, 2012.

a. Within what period of time does FPL expect to incur the $140,000 O&M costs associated with the TROPOS compliance?

b. Please provide a breakdown of the component activities that comprise the estimated $140,000 of O&M costs, and identify the associated affected plants

A.

a. FPL expects to incur the O&M costs associated with the TROPOS between 2012 and 2014. Based on FDEP's approval of the proposed TROPOS on August 9, 2012, and a revised cost estimate received from the vendor who developed the TROPOS that included $50,000 for a second year of the required Decay Study that had been inadvertently omitted in the previous estimate, FPL now estimates the cost of the TROPOS to be $190,000, rather than the $140,000 estimate that was submitted previously.

b. Below is a breakdown of the component activities that comprise the St. Lucie Plant TROPOS. St. Lucie is the only FPL plant that currently has a requirement to conduct this study.

St. Lucie Plant TROPOS - Estimated O&M Costs	
Activity	**Total**
Kickoff and Mobilization	$35,000
Dye Study	$15,000
Decay Study	$110,000
Plant-Level Verification	$15,000
Reporting	$15,000
Total	$190,000

Q. Please refer to pages 18 - 20 of witness Labauve's testimony.

a. When will the engineering study be completed?

b. What is the estimated cost of FPL's share of the economic study for MATS at SJRPP units?

c. Has FPL adjusted its 2012 MATS O&M predictions to include the cost discussed in response to question No. 56b? Please explain.

A.

a. FPL expects completion of the study will occur in November 2012.
b. FPL's estimated cost for its ownership share of the study is between $20,000 - $30,000.
c. Yes. FPL adjusted its 2012 ECRC O&M projections to include the cost discussed in section b.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12th day of September, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 53 from STAFF'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 53-56) in Docket No. 120007-EI, and that the response is true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of September, 2012.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission EE130697
Expires 11/05/2015

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12th day of September, 2012, 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 answers to interrogatory numbers 54 and 56 from STAFF'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 53-56) in Docket No. 120007-EI, and that the responses are 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 12th day of September, 2012.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Jessica Alexander Johnson
My Commission EE108855
Expires 03/02/2015

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 5TH day of September, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ronald H. Hix, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 55 from STAFF'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 53-56) in Docket No. 120007-EI, and that the response is true and correct based on his personal knowledge.

Ronald H. Hix

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 5TH day of September, 2012.

Lois M Sivia
Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission EE130697
Expires 11/05/2015

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FPL's Response to Staff's 7th Set of Interrogatories (Nos. 57-58)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	Docket No: 120007-EI Date: October 4, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S SEVENTH SET OF INTERROGATORIES (Nos. 57-58) AND SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (No. 2)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-12-0060-PCO-EI, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff") Seventh Set of Interrogatories (Nos. 57-58) and Second Request for Production of Documents (No. 2).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the documents, if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these

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responses provide all of the information that FPL obtained after a reasonable and diligent search conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is duplicative not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as unduly burdensome and purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to

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lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the Florida Public Service Commission in this docket. To require any non-regulated entities to participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevance of the information provided in its responses.

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II. Responses

Seventh Set of Interrogatories (Nos. 57-58). Attached hereto are FPL's answers to Interrogatory Nos. 57 through 58 of Staff's Seventh Set of Interrogatories, consistent with its objections and together with the affidavits of the persons providing the answers.

Second Request for Production of Documents (No. 2). Attached hereto is FPL's response to Staff's Second Request for Production of Documents No. 2, consistent with the objections. FPL is providing all non-confidential responsive documents directly to Staff. In addition, FPL filed with the FPSC clerk a disk containing the confidential documents, along with a Notice of Intent to Request Confidential Classification.

Respectfully submitted this 4th day of October 2012.

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Maria J. Moncada, Esq.
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By: *s/ Maria Jose Moncada*
Maria Jose Moncada
Fla. Bar No. 0773301

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CERTIFICATE OF SERVICE
Docket No. 120007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Objections and Responses to the Staff of the Florida Public Service Commission's Seventh Set of Interrogatories (Nos. 57-58) and Second Request for Production of Documents (No. 2) has been furnished by electronic mail and United States Mail on this 4th day of October 2012, to the following:

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By: *s/ Maria Jose Moncada*
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Q.

Please refer to witness T. Keith's testimony filed on August 30, 2012, for the following questions.

On page 5, lines 4 – 18, Witness Keith describes that a change in methodology.

a. Please explain why the old methodology was used.

b. Please explain why FPL is changing its methodology.

c. What is meant by "the historical relationship between sales by rate schedule and sales by revenue class?"

d. What is the effect on FPL's proposed 2013 ECRC factors resulting from the change of the methodology?

A.

a. FPL used the old methodology because in the past, forecasting by rate code was only done during rate proceedings, which occurred infrequently.

b. The proposed method is the same as that used in FPL's rate case in Docket 120015-EI, and it has been used for rate case forecasting purposes every year since at least 1999. For revenue forecast purposes, FPL develops the allocation of customers and kWh sales by rate schedule based on the historical relationship between the number of customers and sales by rate schedule, and customers and sales by revenue class. The result is an estimate of sales and customers by retail rate schedule for the appropriate time period that ties to the revenue class forecast of sales, customer, and use per customer produced by the load forecasting department. FPL believes that this methodology produces a more precise allocation than that previously used for the calculation of its clause charges. Under the methodology used previously, the rate class sales allocations were impacted by extreme weather events even though the total retail sales forecast is weather normalized. For example, the 2012 clause projections filing utilized 2010 actual sales and resulted in more sales being allocated to the RS-1 and RST-1 rates than were forecast for the total residential revenue class, which also includes the OL-1 rate.

c. The historical relationship between sales by rate schedule and sales by revenue class refers to the percentage of customers taking service on each rate schedule that are within each revenue class. For example, approximately 77% of customers on the GS rate are in the commercial revenue class and 23% are in the industrial revenue class (these are mostly temporary service customers). The revenue classes are Residential, Commercial, Industrial, Street & Highway Lighting, Other Governmental, and Railroads. The historical sales period used in this allocation is twelve months ended September 2011.

d. Below is a comparison of projected 2013 kWh sales and costs by rate class calculated based on both allocation methodologies as well as the impact on the 2013 ECRC factors by rate class.

RATE SCHEDULE	PROJECTED 2013 KWH SALES			
	NEW METHODOLOGY	OLD METHODOLOGY	DIFFERENCE	
RS1/RST1	53,023,166,899	54,541,830,307	(1,518,663,408)	-2.78%
GS1/GST1	5,844,824,242	5,687,162,933	157,661,309	2.77%
GSD1/GSDT1/HLFT1 (21-499 kW)	25,078,522,608	24,342,327,701	736,194,907	3.02%
OS2	12,578,957	12,748,987	(170,030)	-1.33%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	11,310,651,252	10,723,971,804	586,679,448	5.47%
GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	2,450,692,797	2,364,836,837	85,855,960	3.63%
GSLD3/GSLDT3/CS3/CST3	199,482,765	213,167,904	(13,685,139)	-6.42%
SST1T	97,610,914	98,429,398	(818,484)	-0.83%
SST1D1/SST1D2/SST1D3	7,613,528	6,656,484	957,044	14.38%
CILC D/CILC G	3,039,558,994	3,100,056,937	(60,497,943)	-1.95%
CILC T	1,341,477,742	1,354,415,276	(12,937,534)	-0.96%
MET	92,698,007	81,835,199	10,862,808	13.27%
OL1/SL1/PL1	630,970,753	606,635,896	24,334,857	4.01%
SL2, GSCU1	70,594,840	66,368,634	4,226,206	6.37%
TOTAL	103,200,444,298	103,200,444,297		

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RATE SCHEDULE	PROJECTED 2013 ECRC COSTS			
	NEW METHODOLOGY	OLD METHODOLOGY	DIFFERENCE	
RS1/RST1	$121,324,444	$124,426,965	($3,102,521)	-2.5%
GS1/GST1	$11,394,121	$11,055,406	$338,715	3.1%
GSD1/GSDT1/HLFT1 (21-499 kW)	$47,837,534	$46,302,878	$1,534,656	3.3%
OS2	$25,479	$25,742	($263)	-1.0%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	$21,043,978	$19,896,947	$1,147,031	5.8%
GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	$4,064,040	$3,911,226	$152,814	3.9%
GSLD3/GSLDT3/CS3/CST3	$298,992	$318,681	($19,689)	-6.2%
SST1T	$175,502	$176,475	($973)	-0.6%
SST1D1/SST1D2/SST1D3	$15,644	$13,629	$2,015	14.8%
CILC D/CILC G	$5,059,215	$5,146,152	($86,937)	-1.7%
CILC T	$2,116,653	$2,131,430	($14,777)	-0.7%
MET	$169,359	$149,091	$20,268	13.6%
OL1/SL1/PL1	$564,184	$541,566	$22,618	4.2%
SL2, GSCU1	$112,931	$105,886	$7,045	6.7%
TOTAL	$214,202,076	$214,202,074		

Florida Power & Light Company

RATE SCHEDULE	2013 ECRC FACTORS		
	NEW METHODOLOGY	OLD METHODOLOGY	DIFFERENCE
	$/kWh	$/kWh	$/KW
RS1/RST1	0.00229	0.00228	0.00001
GS1/GST1	0.00195	0.00194	0.00001
GSD1/GSDT1/HLFT1 (21-499 kW)	0.00191	0.00190	0.00001
OS2	0.00203	0.00202	0.00001
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	0.00186	0.00186	0.00001
GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	0.00166	0.00165	0.00000
GSLD3/GSLDT3/CS3/CST3	0.00150	0.00149	0.00000
SST1T	0.00180	0.00179	0.00001
SST1D1/SST1D2/SST1D3	0.00205	0.00205	0.00001
CILC D/CILC G	0.00166	0.00166	0.00000
CILC T	0.00158	0.00157	0.00000
MET	0.00183	0.00182	0.00001
OL1/SL1/PL1	0.00089	0.00089	0.00000
SL2, GSCU1	0.00160	0.00160	0.00000

Q.

Please refer to witness T. Keith's testimony filed on August 30, 2012, for the following questions.

Referring to page 6, lines 4 – 19, please explain why FPL chose a four-year capital recovery schedule beginning January 1, 2013, for the Pt. Everglades ESP Project.

A.

The Commission has typically allowed FPL and other electric utilities to amortize capital recovery schedules over a four-year period. FPL believes that a four-year period appropriately balances the goals of rapidly writing off retired property so that it does not continue to require a return as part of rate base, while at the same time not having a disproportionate impact on expenses in any one year.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 3rd day of October, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Renae Deaton, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 57 from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 57-58) in Docket No. 120007-EI, and that the response is true and correct based on her personal knowledge.

RBDeaton

Renae Deaton

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of October, 2012.

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

Traci D. Goldwire

Notary Public
State of Florida, at Large

My Commission Expires:
July 31, 2015

RECEIVED
OCT 11 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 2nd day of October, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Tony Biacci, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 58 from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 57-58) in Docket No. 120007-EI, and that the response is true and correct based on his personal knowledge.

T. Biacci
Tony Biacci

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 2 day of October, 2012.

N Gregory
Notary Public
State of Florida, at Large

NICOLE ANDREA GREGORY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# EE173212
Expires 2/26/2016

My Commission Expires:
EE173212 2/26/2016

8

FPL's Response to Staff's 8th Set of Interrogatories (Nos. 59-62)

RECEIVED
OCT 18 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	Docket No: 120007-EI Date: October 15, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S EIGHTH SET OF INTERROGATORIES (Nos. 59-62)

Florida Power & Light Company ("FPL"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-12-0060-PCO-EI, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff") Eighth Set of Interrogatories (Nos. 59-62).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the documents, if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these responses provide all of the information that FPL obtained after a reasonable and diligent search

conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is duplicative not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as unduly burdensome and purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the

120007 Hearing Exhibits 00178

Florida Public Service Commission in this docket. To require any non-regulated entities to participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevance of the information provided in its responses.

120007 Hearing Exhibits 00179

II. Responses

Eighth Set of Interrogatories (Nos. 59-62). Attached hereto are FPL's answers to Interrogatory Nos. 59 through 62 of Staff's Eighth Set of Interrogatories, consistent with its objections and together with the affidavit of the person providing the answers.

Respectfully submitted this 15th day of October 2012.

R. Wade Litchfield, Esq.
Vice President and General Counsel
John T. Butler, Esq.
Assistant General Counsel-Regulatory
Maria J. Moncada, Esq.
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Telephone: (561) 304-5639
Facsimile: (561) 691-7135

By: *s/ John T. Butler*
John T. Butler
Fla. Bar No. 283479

CERTIFICATE OF SERVICE
Docket No. 120007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Objections and Responses to the Staff of the Florida Public Service Commission's Eighth Set of Interrogatories (Nos. 59-62) has been furnished by electronic mail and United States Mail on this 15th day of October 2012, to the following:

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By: *s/ John T. Butler*
John T. Butler
Fla. Bar No. 283479

Q.

Please refer to FPL's Preliminary List of New Projects for Cost Recovery (List) filed July 10, 2012, for the following questions.

Please specify how the costs associated with FPL's proposed Thermal Discharge Standards project will be allocated to the rate classes and the rationale for such allocation.

A.

O&M costs associated with FPL's proposed Thermal Discharge Standards project should be allocated to the rate classes on an average 12 CP demand basis. This allocation is based on how these costs would be classified and allocated in FPL's current cost of service study. At this time, there are no projected capital costs associated with this project.

Q.

Please refer to FPL's Preliminary List of New Projects for Cost Recovery (List) filed July 10, 2012, for the following questions.

Please specify how the costs associated with FPL's proposed Gopher Tortoise Relocations project will be allocated to the rate classes and the rationale for such allocation.

A.

O&M costs associated with FPL's proposed Gopher Tortoise Relocations project should be allocated to the rate classes on an average 12 CP demand basis. This allocation is based on how these costs would be classified and allocated in FPL's current cost of service study. At this time, there are no projected capital costs associated with this project.

Q.

Please refer to FPL's Preliminary List of New Projects for Cost Recovery (List) filed July 10, 2012, for the following questions.

Please specify how the costs associated with FPL's proposed Effluent Guidelines Revised Rule project will be allocated to the rate classes and the rationale for such allocations.

A.

O&M costs associated with FPL's proposed Effluent Guidelines Revised Rule project should be allocated to the rate classes on an average 12 CP demand basis. This allocation is based on how these costs would be classified and allocated in FPL's current cost of service study. At this time, there are no projected capital costs associated with this project.

Q.
Please refer to FPL's Preliminary List of New Projects for Cost Recovery (List) filed July 10, 2012, for the following questions.

Please specify how the costs associated with FPL's proposed Numeric Nutrient Criteria project will be allocated to the rate classes and the rationale for such allocation.

A.
O&M costs associated with FPL's proposed Numeric Nutrient Criteria project should be allocated to the rate classes on an average 12 CP demand basis. This allocation is based on how these costs would be classified and allocated in FPL's current cost of service study. At this time, there are no projected capital costs associated with this project.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 15th day of October, 2012, 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 acknowledged before me that he provided the answers to interrogatory numbers 59-62 from STAFF'S EIGHTH SET OF INTERROGATORIES TO FLORIDA POWER AND LIGHT COMPANY (NOS. 59-62) in Docket No. 120007-EI, and that the responses are true and correct based on his 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 15 day of October, 2012.

NEYLA CHERASO
Notary Public - State of Florida
My Comm. Expires Sep 22, 2015
Commission # EE 132710

Notary Public
State of Florida, at Large

My Commission Expires:
Sept. 22, 2015

9

FPL's Response to Staff's 1st Production of Documents (No. 1)

Q.
Please provide updated Excel worksheets "DefGain_P1" and "DefGain_P2" for Company provided Excel file "Form 42-8A Pgs 1-52 Final.xls" to demonstrate your response to Interrogatory No. 38 (b).

A.
Updated Excel worksheets "DefGain_P1" and "DefGain_P2" are not needed because they have not changed from those that were provided in the Form 42-8A Excel file. Please refer to these worksheets in file "Form 42-8A Pgs 1-52 Final.xls" that was used in demonstration of the response to Interrogatory No. 38 (b).

10

FPL's Response to Staff's 2nd Production of Documents (No. 2)

Q.

Referring to page 5 of the August 30, 2012, Testimony of T. Keith, Lines 4 - 18. Please provide the worksheets (electronic and hard copy) showing the development of the forecast of sales by retail rate schedule based on the procedure detailed in this section of witness Keith's testimony.

A.

Non-confidential documents responsive to this request will be provided directly to Staff via electronic mail. In addition, FPL filed with the FPSC clerk a disk containing the confidential documents, along with a Notice of Intent to Request Confidential Classification.

CONFIDENTIAL

REDACTED

PCR 13-3007

[redacted]

2008 GSLDT-3

SEL SVC TO	DYS	P	R	RTE	RT	T	FRA	MP	KWH USE	ONP KWH	OFFP KWH	ACT D	ONP D	BIL D
6/29/2011	30	N	2	90		A	170	N	1,058,400	282,133	776,267	1,919	1,919	1,919
5/27/2011	30	N	2	90		A	170	N	851,200	244,932	606,268	1,888	1,888	1,888
4/28/2011	30	N	2	90		A	170	N	672,000	193,874	478,126	1,835	1,835	1,835
3/30/2011	30	N	2	90		A	170	N	879,200	207,280	671,920	1,869	1,443	1,443
2/28/2011	30	N	2	90		A	170	N	812,000	199,862	612,138	1,847	1,847	1,847
1/28/2011	30	N	2	90		A	170	N	784,000	188,564	595,436	1,360	1,385	1,385
12/29/2010	30	N	2	90		A	170	N	864,480	169,308	535,092	1,519	1,518	1,519
11/29/2010	30	N	2	90		A	170	N	1,008,800	236,053	771,967	2,142	1,748	1,748
10/27/2010	30	N	2	90		A	170	N	874,400	275,599	695,801	2,288	2,288	2,288
9/28/2010	30	N	2	90		A	170	N	1,146,000	306,423	841,577	2,253	2,253	2,253
8/27/2010	30	N	2	90		A	170	N	974,400	289,440	684,960	1,980	1,984	2,000
7/28/2010	30	N	2	90		A	170	N	778,400	241,895	536,505	1,995	1,998	2,000
6/29/2010	30	N	2	90		A	170	N	700,000	187,716	512,284	1,332	1,332	2,000
5/28/2010	30	N	2	90		A	170	N	728,000	212,445	515,555	1,337	1,337	2,000
4/29/2010	30	N	2	90		A	170	N	644,000	184,743	459,257	1,194	1,194	2,000
3/31/2010	30	N	2	90		A	170	N	498,400	125,371	372,029	1,186	1,186	2,000
3/2/2010	30	N	2	90		A	170	N	827,200	167,513	459,687	1,236	1,186	2,000
2/1/2010	30	N	2	90		A	170	N	674,303	193,313	520,990	1,299	1,183	2,000
12/30/2009	30	N	2	90		A	170	N	758,000	175,116	580,884	1,457	1,410	2,000
11/25/2009	30	N	2	90		A	170	N	808,480	208,157	598,243	1,818	1,809	2,009
10/27/2009	30	N	2	90		A	170	N	840,000	245,328	594,672	1,825	1,801	2,009
9/28/2009	30	N	2	90		A	170	N	991,200	257,163	734,037	1,801	1,801	2,009
8/27/2009	30	N	2	90		A	170	N	845,600	241,123	604,477	1,853	1,853	2,009
7/28/2009	30	N	2	90		A	170	N	784,000	226,824	557,176	1,843	1,818	2,009
6/29/2009	30	N	2	90		A	170	N	700,000	187,716	512,284	1,332	1,332	2,009
5/29/2009	30	N	2	90		A	170	N	772,800	212,441	560,359	1,399	1,399	1,399
4/29/2009	30	N	2	90		A	170	N	733,600	206,167	527,433	1,552	1,552	1,552
3/31/2009	30	N	2	90		A	170	N	636,400	155,448	482,951	1,304	1,252	1,252
3/2/2009	30	N	2	90		A	170	N	627,200	146,213	480,987	1,181	1,137	1,137
1/30/2009	30	N	2	90		A	170	N	778,134	186,881	595,003	1,960	1,881	1,881
12/30/2008	30	N	2	90		A	170	N	952,000	213,454	738,546	1,389	1,389	1,389
11/26/2008	30	N	2	90		A	170	N	739,200	186,833	552,367	1,490	1,408	1,408
10/27/2008	30	N	2	90		A	170	N	861,200	228,238	632,962	1,848	1,571	1,571
9/26/2008	30	N	2	90		A	170	N	884,800	241,883	642,917	1,804	1,804	1,804
8/27/2008	30	N	2	90		A	170	N	823,200	235,758	587,442	1,715	1,715	1,715
7/28/2008	30	N	2	90		A	170	N	678,200	226,193	453,007	1,524	1,524	1,524
6/27/2008	30	N	2	90		A	170	N	846,888	241,019	604,581	2,080	1,873	1,873
5/29/2008	30	N	2	64		9	A	170	N	778,400	218,155	560,245	1,827	1,827
4/29/2008	30	N	2	64		9	A	170	N	733,600	204,058	529,542	1,388	1,388
3/31/2008	30	N	2	64		9	A	170	N	705,600	165,166	540,434	1,262	1,262
2/29/2008	30	N	2	64		9	A	170	N	621,600	156,163	465,437	1,450	1,243
1/31/2008	30	N	2	64		9	A	170	N	700,000	170,318	529,682	1,484	1,483
12/31/2007	30	N	2	64		9	A	170	N	1,030,400	228,867	801,533	1,715	1,863

[redacted]

2007 CS-2

SEL SVC TO	DYS	P	R	RTE	RT	T	FRAN	MP	KWH USE	ONP KWH	OFFP KWH	ACT D	ONP D	BIL CURT D
6/29/2011	30	N	3	71		9	A	000	2,112,800	4,428	2,108,172	4,428		1,700
5/23/2011	30	N	3	71		9	A	000	1,995,000	4,158	1,990,842	4,158		1,700
4/22/2011	30	N	3	71		9	A	000	1,726,200	4,158	1,722,002	4,158		1,700
3/23/2011	30	N	3	71		9	A	000	1,680,000	4,362	1,675,638	4,362		1,700
2/22/2011	30	N	3	71		9	A	000	1,686,800	4,118	1,682,682	4,118		1,700
1/24/2011	30	N	3	71		9	A	000	1,381,800	3,992	1,377,808	3,992		1,700
12/21/2010	30	N	3	71		9	A	000	1,444,800	4,705	1,440,095	4,705		1,700
11/19/2010	30	N	3	71		9	A	000	1,986,800	5,368	1,980,232	5,368		1,700
10/21/2010	30	N	3	71		9	A	000	1,906,800	6,046	1,901,755	5,046		1,700
9/22/2010	30	N	3	71		9	A	000	2,137,800	5,214	2,132,586	5,214		1,700
8/23/2010	30	N	3	71		9	A	000	2,146,200	5,048	2,141,152	5,048		1,700
7/23/2010	30	N	3	71		9	A	000	1,974,000	5,093	1,968,907	5,093		1,700
6/23/2010	30	N	3	71		9	A	000	2,098,800	5,198	2,093,602	5,198		1,700
5/24/2010	30	N	3	71		9	A	000	2,431,800	5,198	2,426,604	5,198		1,700
4/23/2010	30	N	3	71		9	A	000	2,347,800	5,181	2,342,619	5,181		1,700
3/23/2010	30	N	3	71		9	A	000	2,234,400	4,967	2,229,413	4,967		1,700
2/24/2010	30	N	3	71		9	A	000	2,116,800	5,123	2,111,677	5,123		1,700
1/26/2010	30	N	3	71		9	A	000	1,961,400	4,700	1,956,700	4,709		1,700
12/23/2009	30	N	3	71		9	A	000	1,863,000	4,733	1,948,267	4,733		1,700
11/19/2009	30	N	3	71		9	A	000	2,011,800	4,919	2,006,881	4,919		1,700
10/21/2009	30	N	3	71		9	A	000	2,053,800	4,770	2,049,030	4,778		1,700
9/22/2009	30	N	3	71		9	A	000	2,238,800	4,859	2,233,741	4,859		1,700
8/21/2009	30	N	3	71		9	A	000	1,936,200	5,169	1,931,031	5,169		1,700
7/23/2009	30	N	3	71		9	A	000	2,020,200	5,111	2,015,089	5,111		1,700
6/23/2009	30	N	3	71		9	A	000	2,184,000	5,058	2,178,942	5,058		1,700
5/22/2009	30	N	3	71		9	A	000	1,936,200	4,831	1,931,369	4,831		1,700
4/23/2009	30	N	3	71		9	A	000	1,884,200	4,629	1,879,571	4,629		1,700
3/25/2009	30	N	3	71		9	A	000	1,837,200	4,362	1,832,848	4,362		1,700
2/24/2009	30	N	3	71		9	A	000	1,469,400	4,256	1,466,144	4,256		1,700
1/26/2009	30	N	3	71		9	A	000	1,327,200	5,022	1,322,178	5,022		1,700
12/23/2008	30	N	3	71		9	A	000	1,478,400	5,048	1,473,352	5,048		1,700
11/19/2008	30	N	3	71		9	A	000	1,901,800	5,111	1,796,689	5,111		1,700
10/21/2008	30	N	3	71		9	A	000	1,857,480	5,039	1,852,370	5,030		1,700
9/23/2008	30	N	3	71		9	A	000	2,104,200	5,055	2,099,145	5,056		1,700
8/21/2008	30	N	3	71		9	A	000	2,158,800	5,201	2,153,599	5,201		1,700
7/23/2008	30	N	3	71		9	A	000	2,137,800	5,181	2,132,619	5,191		1,700
6/23/2008	30	N	3	71		9	A	000	2,247,800	5,189	2,241,811	5,189		1,700
5/23/2008	30	N	3	71		9	A	000	2,104,200	5,108	2,099,092	5,199		1,700
4/23/2008	30	N	3	71		9	A	000	2,074,800	5,126	2,069,674	5,126		1,700
3/25/2008	30	N	3	71		9	A	000	1,890,000	5,181	1,884,819	5,181		1,700
2/25/2008	30	N	3	71		9	A	000	2,288,000	5,060	2,283,940	5,060		1,700
1/25/2008	30	N	3	71		9	A	000	2,314,200	5,320	2,308,880	5,320		1,700
12/21/2007	30	N	3	71		9	A	000	2,104,200	5,063	2,099,137	5,063		1,700
11/20/2007	30	N	3	71		9	A	000	2,234,400	5,438	2,228,962	5,438		1,700

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	PCR 13-9887																
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105																	
106	2007																
107	BEL_BAC TO	DYS	P	R	RTE		FRAN			KWH USE	ONP KWH	OFFP KWH	ACT D	ONP D	BIL D	CURT D	
108	7/6/2011	30	N	C	75		470			1,035,200	280,496	754,704	1,889	1,958	1,958	2,035	
109	6/6/2011	30	N	C	75		470			827,200	204,429	622,771	1,708	1,420	1,420	2,035	
110	5/6/2011	30	N	C	75		470			1,086,400	295,012	791,388	2,210	2,191	2,191	2,035	
111	4/6/2011	30	N	C	75		470			1,049,600	258,089	790,511	2,003	2,089	2,089	2,035	
112	3/3/2011	30	N	C	75		470			898,200	224,026	674,589	2,115	2,115	2,115	2,035	
113	2/3/2011	30	N	C	75		470			888,200	230,891	656,309	2,001	1,987	1,987	2,035	
114	1/6/2011	30	N	C	75		470			952,800	213,165	736,635	2,044	2,044	2,044	2,035	
115	12/3/2010	30	N	C	75		470			870,400	221,649	648,754	1,990	1,872	1,872	2,035	
116	11/3/2010	30	N	C	75		470			818,800	230,176	588,624	1,894	1,831	1,831	2,035	
117	10/4/2010	30	N	C	75		470			1,008,800	252,707	756,293	2,887	2,488	2,488	2,035	
118	9/2/2010	30	N	C	75		470			1,100,800	319,500	781,300	2,285	2,285	2,285	2,035	
119	8/4/2010	30	N	C	75		470			992,800	272,945	698,755	2,457	2,148	2,148	2,035	
120	7/6/2010	30	N	C	75		470			923,200	245,847	678,353	2,481	2,073	2,073	2,035	
121	6/4/2010	30	N	C	75		470			882,800	241,973	650,827	2,323	2,030	2,030	2,035	
122	5/5/2010	30	N	C	75		470			934,400	275,322	659,078	2,500	2,106	2,106	2,035	
123	4/6/2010	30	N	C	75		470			908,800	233,912	674,888	2,326	2,326	2,326	2,035	
124	3/6/2010	30	N	C	75		470			838,800	301,892	536,908	1,949	1,879	1,879	2,035	
125	2/5/2010	30	N	C	75		470			809,600	209,753	599,847	1,926	1,800	1,800	2,035	
126	1/6/2010	30	N	C	75		470			1,388,400	314,165	1,076,238	3,096	2,923	2,923	2,035	
127	12/3/2009	30	N	C	75		470			1,288,400	333,679	962,721	2,449	2,449	2,449	2,035	
128	11/3/2009	30	N	C	75		470			1,118,200	300,943	814,257	2,313	2,248	2,248	2,035	
129	10/2/2009	30	N	C	75		470			1,091,200	307,094	784,116	2,898	2,041	2,041	2,035	
130	9/2/2009	30	N	C	75		470			918,400	265,048	653,364	2,210	2,116	2,116	2,035	
131	8/4/2009	30	N	C	75		470			891,200	236,679	654,521	1,888	1,929	1,929	2,035	
132	7/6/2009	30	N	C	75		470			838,200	255,309	582,891	2,196	2,183	2,183	2,035	
133	6/4/2009	30	N	C	75		470			1,033,600	291,220	742,380	2,884	2,512	2,512	2,035	
134	5/5/2009	30	N	C	75		470			928,000	283,800	644,200	2,084	1,958	1,958	2,035	
135	4/6/2009	30	N	C	75		470			1,116,200	276,003	840,197	2,393	2,393	2,393	2,035	
136	3/6/2009	30	N	C	75		470			737,800	182,380	555,249	1,852	1,852	1,852	2,035	
137	2/5/2009	30	N	C	75		470			738,000	178,782	559,248	1,586	1,586	1,586	2,035	
138	1/6/2009	30	N	C	75		470			913,800	202,890	710,710	1,818	1,818	1,818	2,035	
139	12/3/2008	30	N	C	75		470			888,200	211,353	667,847	1,808	1,808	1,808	2,035	
140	10/31/2008	30	N	C	75		470			1,233,800	337,838	895,961	2,806	2,444	2,444	2,035	
141	10/2/2008	30	N	C	75		470			1,298,800	374,193	924,607	2,820	2,820	2,820	2,035	
142	9/3/2008	30	N	C	75		470			1,238,400	348,283	891,117	2,854	2,854	2,854	2,035	
143	8/4/2008	30	N	C	75		470			1,381,800	368,231	1,012,388	2,479	2,436	2,436	2,035	
144	7/3/2008	30	N	C	75		470			1,214,400	351,280	863,188	2,283	2,283	2,283	2,035	
145	6/4/2008	30	N	C	75		470			1,168,400	338,880	829,520	2,232	2,130	2,130	2,035	
146	5/5/2008	30	N	C	75		470			1,288,000	333,047	922,953	2,147	2,085	2,085	2,035	
147	4/4/2008	30	N	C	75		470			1,168,400	287,098	881,302	2,340	2,180	2,180	2,035	
148	3/5/2008	30	N	C	75		470			1,208,800	311,715	896,286	2,805	2,395	2,395	2,035	
149	2/6/2008	30	N	C	75		470			1,220,400	336,363	884,037	2,387	2,387	2,387	2,035	
150	1/7/2008	30	N	C	75		470			1,312,000	298,800	1,013,800	2,236	2,186	2,186	2,035	
151																	
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153																	
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155																	
156	2003																
157	BEL_BAC TO	DYS	P	R	RTE	T	FRAI	MF		KWH USE	ONP KWH	OFFP KWH	ACT D	ONP D	BIL D	CURT D	
158	6/27/2011	30	N	3	82	A	170	N		784,000	32,941	751,059	7,031	699	699	700	
159	5/25/2011	30	N	3	82	A	170	N		644,000	30,185	613,815	7,048	302	302	700	
160	4/26/2011	30	N	3	82	A	170	N		630,000	28,258	601,742	7,048	218	218	700	
161	3/28/2011	30	N	3	82	A	170	N		770,000	26,038	743,964	7,038	210	210	700	
162	2/24/2011	30	N	3	82	A	170	N		548,000	24,284	521,716	7,022	219	210	700	
163	1/26/2011	30	N	3	82	A	170	N		926,000	24,822	901,178	7,064	412	412	700	
164	12/27/2010	30	N	3	82	A	170	N		356,000	25,841	310,369	7,066	244	244	700	
165	11/23/2010	30	N	3	82	A	170	N		626,000	27,371	798,629	7,066	370	370	700	
166	10/25/2010	30	N	3	82	A	170	N		778,000	26,396	740,604	7,073	227	227	700	
167	9/24/2010	30	N	3	82	A	170	N		602,000	31,844	570,156	7,073	361	361	700	
168	8/25/2010	30	N	3	82	A	170	N		518,000	33,264	484,736	7,066	420	420	700	
169	7/27/2010	30	N	3	82	A	170	N		1,106,000	31,231	1,074,769	7,061	462	462	700	
170	6/25/2010	30	N	3	82	A	170	N		860,000	30,454	829,546	7,132	363	363	700	
171	5/26/2010	30	N	3	82	A	170	N		882,000	30,101	851,899	7,061	454	454	700	
172	4/27/2010	30	N	3	82	A	170	N		924,000	26,972	897,028	7,106	420	420	700	
173	3/29/2010	30	N	3	82	A	170	N		1,120,000	23,391	1,096,609	7,031	336	336	700	
174	2/26/2010	30	N	3	82	A	170	N		798,000	24,469	773,531	7,073	420	420	700	
175	1/28/2010	30	N	3	82	A	170	N		668,000	26,304	631,796	7,014	512	512	700	
176	12/28/2009	30	N	3	82	A	170	N		480,000	26,894	453,406	7,048	512	512	700	
177	11/25/2009	30	N	3	82	A	170	N		784,000	25,196	758,804	7,039	280	280	700	
178	10/23/2009	30	N	3	82	A	170	N		812,000	35,915	776,085	7,064	571	571	700	
179	9/24/2009	30	N	3	82	A	170	N		982,000	36,717	918,283	7,064	613	613	700	
180	8/25/2009	30	N	3	82	A	170	N		784,000	35,885	748,115	7,066	596	596	700	
181	7/27/2009	30	N	3	82	A	170	N		1,120,000	32,659	1,087,341	7,066	563	563	700	
182	6/25/2009	30	N	3	82	A	170	N		498,000	32,564	378,446	7,064	546	546	700	
183	5/27/2009	30	N	3	82	A	170	N		548,000	29,047	518,953	7,031	244	244	700	
184	4/27/2009	30	N	3	82	A	170	N		896,800	29,899	867,201	7,132	560	560	700	
185	3/27/2009	30	N	3	82	A	170	N		952,880	25,903	926,367	7,165	227	227	700	
186	2/26/2009	30	N	3	82	A	170	N		838,000	25,570	812,330	7,207	235	235	700	
187	1/28/2009	30	N	3	82	A	170	N		966,000	27,212	938,788	7,199	269	269	700	
188	12/26/2008	30	N	3	82	A	170	N		1,330,000	28,207	1,301,793	7,199	244	244	700	
189	11/21/2008	30	N	3	82	A	170	N		1,134,000	28,245	1,105,755	7,157	284	284	700	
190	10/23/2008	30	N	3	82	A	170	N		1,105,000	34,310	1,071,690	7,109	840	840	700	
191	9/24/2008	30	N	3	82	A	170	N		1,302,000	35,150	1,266,850	7,132	353	353	700	
192	8/25/2008	30	N	3	82	A	170	N		1,232,000	33,146	1,198,854	7,132	302	302	700	
193	7/25/2008	30	N	3	82	A	170	N		1,288,000	33,999	1,254,001	7,132	336	336	700	
194	6/25/2008	30	N	3	82	A	170	N		1,274,000	36,229	1,237,771	7,182	378	378	700	
195	5/27/2008	30	N	3	82	A	170	N		1,540,000	35,423	1,504,577	7,165	437	437	700	
196	4/25/2008	30	N	3	82	A	170	N		1,260,000	34,385	1,225,615	7,060	445	445	700	
197	3/27/2008	30	N	3	82	A	170	N		1,218,000	29,081	1,188,919	7,148	336	336	700	
198	2/27/2008	30	N	3	82	A	170	N		1,022,000	30,801	991,399	7,140	378	378	700	
199	1/29/2008	30	N	3	82	A	170	N		882,000	30,757	851,243	7,038	395	395	700	
200	12/27/2007	30	N	3	82	A	170	N		1,036,000	32,474	1,003,526	7,123	554	554	700	

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2006

SEL SVC TO	DYS	P	R	ARTER	T	FRMP	KWH USE	ONP KWH	OFFPK KWH	ACT D	ONP D	BIL D
7/6/2011	30	N	3	265	A	S N	159,000	14,960	136,050	360	364	364
6/7/2011	30	N	3	265	A	S N	188,640	2,882	158,748	424	299	299
5/6/2011	30	N	3	265	A	S N	145,680			355		355
4/7/2011	30	N	3	265	A	S N	202,880			824		824
3/7/2011	30	N	3	265	A	S N	1,790,880			5,388		5,388
2/7/2011	30	N	3	265	A	S N	2,851,920			6,159		6,159
1/7/2011	30	N	3	265	A	S N	2,878,080			6,131		6,131
12/7/2010	30	N	3	265	A	S N	2,025,440			5,099		5,099
11/4/2010	30	N	3	265	A	S N	1,242,960			4,025		4,025
10/8/2010	30	N	3	265	A	S N	173,040			587		587
9/7/2010	30	N	3	265	A	S N	186,480	17,848	168,632	405	375	375
8/6/2010	30	N	3	265	A	S N	153,120	15,295	137,826	362	346	346
7/8/2010	30	N	3	265	A	S N	159,840	16,819	143,021	407	374	374
6/8/2010	30	N	3	265	A	S N	150,600	5,795	156,806	493	343	343
5/7/2010	30	N	3	265	A	S N	141,120			440		440
4/6/2010	30	N	3	265	A	S N	874,400			3,667		3,667
3/10/2010	30	N	3	265	A	S N	1,593,600			3,899		3,899
2/8/2010	30	N	3	265	A	S N	2,398,310			3,933		3,933
1/8/2010	30	N	3	265	A	S N	2,858,360			4,982		4,982
12/7/2009	30	N	3	265	A	S N	2,125,880			5,275		5,275
11/4/2009	30	N	3	265	A	S N	418,080			2,491		2,491
10/8/2009	30	N	3	265	A	S N	179,280			491		491
9/4/2009	30	N	3	265	A	S N	137,580	16,821	120,889	528	404	404
8/6/2009	30	N	3	265	A	S N	126,000	12,290	113,710	465	327	327
7/8/2009	30	N	3	265	A	S N	184,080	16,287	137,823	436	419	419
6/8/2009	30	N	3	265	A	S N	155,760	4,003	151,757	387	365	365
5/7/2009	30	N	3	265	A	S N	138,000			329		329
4/6/2009	30	N	3	265	A	S N	908,147			1,363		1,363
3/10/2009	30	N	3	265	A	S N	2,980,400			5,255		5,255
2/6/2009	30	N	3	265	A	S N	3,112,880			5,984		5,984
1/8/2009	30	N	3	265	A	S N	2,738,800			5,147		5,147
12/5/2008	30	N	3	265	A	S N	2,841,360			6,851		6,851
11/4/2008	30	N	3	265	A	S N	702,000			4,381		4,381
10/8/2008	30	N	3	265	A	S N	171,840			559		560
9/5/2008	30	N	3	265	A	S N	132,720	13,780	118,960	464	322	322
8/6/2008	30	N	3	265	A	S N	132,000	13,537	118,663	338	319	319
7/8/2008	30	N	3	265	A	S N	145,440	13,468	131,972	368	359	359
6/6/2008	30	N	3	265	A	S N	138,440	8,870	130,370	384	314	314
5/7/2008	30	N	3	265	A	S N	188,480			1,784		1,784
4/8/2008	30	N	3	265	A	S N	1,778,280			4,280		4,280
3/10/2008	30	N	3	265	A	S N	2,887,840			5,250		5,250
2/8/2008	30	N	3	265	A	S N	2,885,120			4,833		4,833
1/8/2008	30	N	3	265	A	S N	3,381,120			4,556		4,556

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2008

SVC DATE	RM	D	T	C	KWH USE	ONPK KWH	OFFPK KWH	KWD
7/19/2011	7	S	A	B	91,920	2,534	89,386	80
6/15/2011	6	S	A	B	113,280	5,749	107,531	151
5/16/2011	5	S	A	B	92,160	7,885	84,275	132
4/15/2011	4	S	A	B	104,640	8,002	96,638	181
3/16/2011	3	S	A	B	95,040	9,478	85,562	214
2/15/2011	2	S	A	B	125,040	10,164	114,876	165
1/18/2011	1	S	A	B	123,120	9,807	113,313	184
12/14/2010	12	S	A	B	109,440	10,982	98,578	213
11/12/2010	11	S	A	B	115,798	8,821	106,977	144
10/14/2010	10	S	A	B	118,080	4,800	113,488	228
9/15/2010	9	S	A	B	108,240	2,544	105,696	84
8/16/2010	8	S	A	B	103,920	2,727	101,193	98
7/16/2010	7	S	A	B	95,280	2,300	92,980	94

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2004

SVC TO	DYS	P	R	T	FRAN	MP	KWH USE	ONP KWH	OFFPK KWH	ACT D	ONP D	BIL D
7/29/2011	30	N	3	A	610	N	240	19	221	1		
6/30/2011	30	N	3	A	610	N	80,160	1,579	78,581	557	306	306
5/31/2011	30	N	3	A	610	N	153,480	38,241	115,239	517	514	514
4/29/2011	30	N	3	A	610	N	172,800	44,168	128,632	516	517	517
3/31/2011	30	N	3	A	610	N	129,840	89	128,751	486		
2/28/2011	30	N	3	A	610	N	93,360	51	93,309	452		
1/31/2011	30	N	3	A	610	N	35,280	51	36,229	477		
12/30/2010	30	N	3	A	610	N	160,200	24,261	135,949	507	501	501
11/30/2010	30	N	3	A	610	N	91,680	55	91,625	494		
10/28/2010	30	N	3	A	610	N	148,080	59	148,501	498	1	1
9/29/2010	30	N	3	A	610	N	45,360	19	45,341	501		
8/30/2010	30	N	3	A	611	N	38,520	21	38,499	510		
7/30/2010	30	N	3	A	612	N	15,120	22	15,098	493		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	PCR 13-3887																
2	85758-92051 [redacted]																
3																	
4	2364																
5	SVC	TO	DYS	P	R	ARTER	T		FIMP	KWH USE	ONP KWH	OFFPK KWH	ACT D	ONP D	BIL D		
6		7/12/2011	30	N	C	364	N		S N	116,848	21,043	95,587	523	449	449		
7		6/9/2011	30	N	C	364	N		S N	123,380	42,746	80,614	489	491	491		
8		5/10/2011	30	N	C	364	N		S N	136,980	57,881	78,399	477	477	477		
9		4/11/2011	30	N	C	364	N		S N	105,800	35,059	70,891	462	461	461		
10		3/9/2011	30	N	C	364	N		S N	88,449	28,254	62,188	373	383	383		
11		2/9/2011	30	N	C	364	N		S N	105,128	28,234	76,898	524	445	445		
12		1/11/2011	30	N	C	364	N		S N	95,160	22,815	72,345	376	353	353		
13		12/9/2010	30	N	C	364	N		S N	109,803	29,589	80,214	416	368	368		
14		11/8/2010	30	N	C	364	N		S N	132,366	46,822	85,336	510	510	510		
15		10/8/2010	30	N	C	364	N		S N	131,160	31,727	99,433	523	497	497		
16		9/8/2010	30	N	C	364	N		S N	142,680	23,846	118,834	582	546	546		
17		8/10/2010	30	N	C	370	N		S N	90,240	16,241	73,999	499	379	379		
18		7/12/2010	30	N	C	370	N		S N	87,900	12,197	75,703	499	393	393		

FOR 12-3888

[redacted]

DSH

SVC DT	RM	DYS	T	S	BILL KWH	KWD
2/23/2011	2	29	A	S	1,886,800	4,116
1/24/2011	1	34	A	S	1,361,600	3,662
12/21/2010	12	32	A	S	1,444,800	4,706
11/19/2010	11	29	A	S	1,986,600	5,368
10/21/2010	10	29	A	S	1,908,800	5,048
9/22/2010	9	30	A	S	2,137,600	5,214
8/23/2010	8	31	A	S	2,140,200	5,046
7/23/2010	7	30	A	S	1,974,000	5,003
6/23/2010	6	30	A	S	2,085,800	5,108
5/24/2010	5	31	A	S	2,481,600	5,166
4/23/2010	4	29	A	S	2,347,600	5,351
3/25/2010	3	29	A	S	2,234,400	4,967
2/24/2010	2	29	A	S	2,119,800	5,123
1/26/2010	1	35	A	S	1,961,400	4,700
12/23/2009	12	33	A	S	1,953,000	4,733
11/19/2009	11	29	A	S	2,611,800	4,919
10/21/2009	10	29	A	S	2,053,800	4,770
9/22/2009	9	32	A	S	2,238,600	4,859

200910	200911	200912	201001	201002	201003
2,053,800	2,011,800	1,953,000	1,961,400	2,119,800	2,234,400

[redacted]

Bill's Started in October 2009

BAC DATE	RM	DYS	T	C	ONPK KWH	OFFPK KWH	TOTAL KWH	KWD	
2/16/2011	2	29	A	S	14,279	316,921	331,200	105	2/75
1/12/2011	1	33	A	S	13,367	140,285	153,600	98	2/75
12/10/2010	12	31	A	S	13,922	230,678	344,600	95	2/75
11/8/2010	11	29	A	S	14,999	162,633	177,600	101	2/75
10/11/2010	10	31	A	S	14,357	187,243	201,600	98	2/75
9/10/2010	9	30	A	S	16,852	224,248	240,000	111	2/75
8/11/2010	8	29	A	S	16,240	253,880	268,800	114	2/75
7/13/2010	7	32	A	S	14,949	340,281	355,200	111	2/75
6/11/2010	6	30	A	S	14,028	230,772	244,800	112	2/75
5/12/2010	5	29	A	S	14,327	138,273	153,600	111	2/75
4/13/2010	4	29	A	S	13,633	202,367	216,000	105	2/75
3/16/2010	3	31	L	S	38,957	236,743	273,600	2,762	2/76
2/13/2010	2	30	L	S			338,200	3,764	2/71
1/13/2010	1	30	L	S			273,600	3,957	2/71
12/10/2009	12	30	L	S			369,600	3,709	2/71
11/9/2009	11	30	L	S			369,600	3,680	2/71
10/8/2009	10	30	L	S			307,200	3,631	2/71
9/10/2009	9	0	F	S			0	0	2/71
9/10/2009	9	30	A	S			236200	3509	2/71
8/11/2009	8	29	A	S			362800	3800	2/71
7/13/2009	7	32	A	S			374400	3414	2/71
6/11/2009	6	30	L	S			378200	3308	2/71
5/12/2009	5	29	L	S			360000	3625	2/71
4/13/2009	4	31	L	S			310800	3482	2/71
3/13/2009	3	29	L	S			516800	2510	2/71
2/12/2009	2	30	L	S			486200	2817	2/71
1/13/2009	1	34	L	S			328400	2493	2/71

200910	200911	200912	201001	201002	201003
307,200	360,800	368,800	273,600	355,200	273,600

[redacted]

2/71 Final Billed in September 2009

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[redacted]

Service A Code from 2000

SVC DATE	RM	DYS	T	C	ONPK KWH	OFFPK KWH	TOTAL KWH	KWD
2/28/2011	2	29	A	B	199,892	812,108	912,000	1,847
1/28/2011	1	30	A	B	188,564	595,436	784,000	1,386
12/28/2010	12	30	A	B	169,388	525,092	694,400	1,519
11/29/2010	11	33	L	B	236,033	771,967	1,008,000	1,748
10/27/2010	10	29	L	B	278,599	695,801	974,400	2,398
9/28/2010	9	32	A	B	308,423	841,577	1,149,800	2,353
8/27/2010	8	29	A	B	280,440	694,080	974,400	2,000
7/29/2010	7	30	A	B	241,895	536,505	778,400	2,000
6/29/2010	6	32	A	B	187,716	512,284	700,000	2,000
5/28/2010	5	29	A	B	212,445	515,555	728,000	2,000
4/29/2010	4	29	A	B	184,743	489,257	644,000	2,000
3/31/2010	3	29	A	B	126,371	372,029	498,400	2,000
3/2/2010	2	29	A	B	157,513	469,887	627,200	2,000
2/1/2010	1	33	L	B	163,313	520,998	674,303	2,000
12/30/2009	12	35	L	B	178,116	580,884	758,000	2,000
11/23/2009	11	29	L	B	308,157	598,243	906,400	2,000
10/27/2009	10	33	L	B	245,328	594,672	840,000	2,000
9/28/2009	9	32	L	B	267,163	734,037	991,200	2,000

200910	200911	200912	201001	201002	201003
840,000	808,400	798,000	674,303	627,200	498,400

[redacted]

SVC DATE	RM	DYS	T	C	ONPK KWH	OFFPK KWH	TOTAL KWH	KWD
2/24/2011	2	29	A	B	34,394	821,716	646,800	310
1/28/2011	1	30	A	B	34,822	801,178	826,000	412
12/27/2010	12	34	A	B	25,641	310,359	336,000	244
11/23/2010	11	29	A	B	27,371	798,629	826,000	370
10/25/2010	10	31	A	B	29,395	740,804	770,800	227
9/24/2010	9	30	A	B	31,844	570,156	602,000	361
8/25/2010	8	29	A	B	33,264	484,736	518,800	420
7/27/2010	7	32	A	B	31,231	1,974,769	1,106,000	462
6/28/2010	6	30	A	B	30,454	529,546	560,000	353
5/26/2010	5	29	A	B	39,101	851,899	982,000	464
4/27/2010	4	29	A	B	28,972	897,028	924,000	420
3/29/2010	3	31	A	B	23,591	1,096,409	1,120,000	336
2/26/2010	2	29	A	B	24,469	773,531	798,000	428
1/28/2010	1	31	A	B	28,204	631,796	660,000	512
12/28/2009	12	35	A	B	28,594	463,406	490,000	512
11/23/2009	11	31	A	B	28,196	756,804	784,000	360
10/23/2009	10	29	A	B	33,915	778,085	812,000	571
9/24/2009	9	30	A	B	35,717	916,283	952,000	613

200910	200911	200912	201001	201002	201003
812,000	784,000	490,000	658,000	798,000	1,120,000

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SVC DATE	RM	DYS	T	C	ONPK KWH	OFFPK KWH	TOTAL KWH	KWD
2/2/2011	2	29	A	B	230,891	669,309	900,200	1,567
1/5/2011	1	33	A	B	213,165	788,835	902,000	2,044
12/2/2010	12	31	A	B	221,846	648,754	870,400	1,672
11/3/2010	11	28	A	B	230,176	585,824	816,000	1,531
10/4/2010	10	32	A	B	252,707	755,293	1,008,000	2,486
9/2/2010	9	29	A	B	319,500	781,300	1,100,800	2,265
8/4/2010	8	29	A	B	272,045	660,756	932,800	2,146
7/6/2010	7	32	A	B	249,847	676,353	923,200	2,073
6/4/2010	6	30	A	B	241,973	680,827	922,800	2,030
5/5/2010	5	29	A	B	275,322	658,078	934,400	2,166
4/6/2010	4	29	A	B	233,912	674,088	908,000	2,326
3/8/2010	3	31	A	B	201,892	626,908	828,800	1,679
2/5/2010	2	30	A	B	209,753	699,847	909,600	1,800
1/6/2010	1	34	A	B	314,165	1,070,235	1,384,400	2,923
12/3/2009	12	31	A	B	333,679	962,721	1,296,400	2,448
11/2/2009	11	31	A	B	300,943	814,257	1,115,200	2,248
10/2/2009	10	30	A	B	307,084	784,116	1,091,200	2,841

200910	200911	200912	201001	201002	201003
1,091,200	1,115,200	1,296,400	1,380,400	809,600	828,800

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[redacted]

SVC DATE	RM	DYS	T	C	*	ONPK KWH	OFFPK KWH	TOTAL KWH	KWD
2/4/2011	2		28	A	B	1,476	12,368	13,844	4332
1/8/2011	1		33	A	B	-	-	-	4332
12/8/2010	12	30	A	B		375,821	1,337,106	1,713,027	4332
11/8/2010	11	30	A	B		184,816	308,280	493,796	4332
10/8/2010	10	32	A	B		216,866	553,972	770,837	4332
9/3/2010	9	29	A	B		221,088	503,169	724,257	4332
8/5/2010	8	29	A	B		211,414	509,514	720,928	4332
7/7/2010	7	30	A	B		219,833	533,180	752,613	4332
6/7/2010	6	32	A	B		216,886	558,341	774,206	4332
5/6/2010	5	28	A	B		210,832	493,648	704,280	4332
4/7/2010	4	29	A	B		186,864	547,516	733,479	4332
3/8/2010	3	29	A	B			1	1	4332
2/8/2010	2	32	A	B			1	1	4332
1/7/2010	1	34	A	B		3,384	14,590	17,974	4332
12/4/2009	12	31	A	B		1,367	10,280	11,647	4332
11/6/2009	11	29	A	B		124,782	266,981	391,883	4332
10/5/2009	10	32	A	B		208,267	532,057	741,424	4332
9/3/2009	9	29	A	B		211,748	486,958	698,702	4332
8/6/2009	8	29	A	B		196,636	480,572	676,708	4332
7/7/2009	7	32	A	B		207,134	595,283	702,417	4332
6/5/2009	6	30	A	B		211,533	507,076	718,609	4332
5/6/2009	5	29	A	B		208,462	485,589	699,051	4332
4/7/2009	4	29	A	B		172,296	497,544	669,840	4332
3/6/2009	3	31	A	B		312,843	1,066,340	1,379,183	4332
2/6/2009	2	30	A	B		314,488	969,042	1,283,528	4061
1/7/2009	1	34	A	B		35,412	86,398	91,810	3657
12/4/2008	12	31	A	B		254,144	871,259	1,125,812	3557
11/3/2008	11	31	A	B		218,218	603,714	821,930	3254
10/3/2008	10	29	A	B		215,757	497,576	713,633	3018
9/4/2008	9	30	A	B		220,827	536,780	751,607	3018
8/5/2008	8		29	A	B	208,771	486,044	696,815	3018
7/7/2008	7		32	A	B	201,803	550,166	751,968	3015
6/5/2008	6		30	A	B	208,288	496,272	704,530	3018
5/6/2008	5		29	A	B	207,909	481,372	689,281	3018
4/7/2008	4		31	A	B	174,823	553,159	727,782	3018
3/7/2008	3		29	A	B	40,089	127,030	167,119	3018
2/7/2008	2		30	A	B	4,192	7,315	11,507	3018
1/8/2008	1		34	A	B	3,004	14,863	17,867	3018
11/22/2007	11		28	A	B	108,749	280,641	389,388	3388
10/4/2007	10		29	L	B	223,080	508,171	732,231	3388
9/6/2007	9		30	A	B	225,829	495,840	721,669	3388
8/6/2007	8		31	A	B	218,804	570,381	789,665	3388
7/8/2007	7		30	A	B	210,332	516,842	726,974	3388

200810	200811	200812	200901	200902	200903
741,424	391,883	11,647	17,974	1	1

200810	200811	200812	200901	200902	200903
713,633	821,930	1,125,812	91,810	1,283,528	1,379,183

200810	200811	200812	200901	200902	200903
721,669	732,231	389,388	17,867	11,507	167,119

Average

725,575	648,615	499,145	42,504	431,679	515,434

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SVC DATE	RM	DYS	T	C	ONPK KWH	OFFPK KWH	TOTAL KWH	KWD
3/7/2011	2		31	A	B		2,851,920	2,851,920	6,139
1/7/2011	1		31	A	B		2,878,080	2,878,080	5,131
12/7/2010	12		33	A	B		3,025,440	3,025,440	5,089
11/4/2010	11		29	A	B		1,242,000	1,242,000	4,025
10/8/2010	10		29	A	B		173,040	173,040	587
9/7/2010	9		32	A	B	17,648	168,832	186,480	375
8/6/2010	8		29	A	B	15,295	137,825	153,120	346
7/8/2010	7		30	A	B	16,819	143,021	159,840	374
6/8/2010	6		32	A	B	3,795	155,805	159,600	343
5/7/2010	5		29	A	B		141,120	141,120	440
4/6/2010	4		28	A	B		674,400	674,400	3,887
3/10/2010	3		28	A	B		1,663,800	1,663,800	3,889
2/8/2010	2		32	A	B		2,386,310	2,386,310	3,933
1/8/2010	1		32	A	B		2,855,360	2,855,360	4,882
12/7/2009	12		33	A	B		2,125,680	2,125,680	5,275
11/4/2009	11		29	A	B		418,080	418,080	2,481
10/6/2009	10		32	A	B		179,200	179,200	491
9/4/2009	9		29	A	B	16,821	120,899	137,520	404
8/6/2009	8		29	A	B	12,298	113,710	126,000	327
7/8/2009	7		30	A	B	16,257	137,823	154,080	419
6/5/2009	6		32	A	B	4,000	151,767	155,760	366
5/7/2009	5		29	A	B		138,009	138,009	329
4/6/2009	4		29	A	B		908,147	908,147	1,363
3/10/2009	3		29	A	B		2,880,408	2,880,408	6,255
2/6/2009	2		32	A	B		3,112,560	3,112,560	5,984
1/8/2009	1		34	A	B		2,783,809	2,783,809	5,147
12/5/2008	12		31	A	B		2,841,360	2,841,360	6,651
11/4/2008	11		29	A	B		702,009	702,009	4,381
10/6/2008	10		31	A	B		171,840	171,840	580
9/5/2008	9		30	A	B	13,799	118,999	132,720	322
8/6/2008	8		28	A	B	13,337	118,663	132,000	319
7/8/2008	7		32	A	B	13,488	131,972	145,440	359
6/6/2008	6		30	A	B	3,079	136,370	139,449	314
5/7/2008	5		28	A	B		156,480	156,480	1,784
4/8/2008	4		29	A	B		1,775,288	1,775,288	4,290
3/10/2008	3		31	A	B		2,887,840	2,887,840	5,250
2/6/2008	2		30	A	B		2,885,120	2,885,120	4,833
1/8/2008	1		34	A	B		3,351,120	3,351,120	4,556
12/6/2007	12		31	A	B		2,788,280	2,788,280	5,289
11/5/2007	11		31	A	B		942,960	942,960	3,360
10/5/2007	10		29	A	B		165,600	165,600	588
9/6/2007	9		30	A	B	18,882	130,028	145,920	321
8/7/2007	8		28	A	B	12,675	109,005	121,680	300

200810	200811	200812	200901	200902	200903
179,280	418,080	2,125,680	2,855,360	2,386,310	1,663,800

SVC DATE	RM	DYS	T	C	ONPK
1/7/2011	1		31 A	B	
12/7/2010	12		33 A	B	
11/4/2010	11		29 A	B	
10/8/2010	10		29 A	B	

200810	200811	200812	200901	200902	200903
171,840	702,009	2,841,360	2,783,809	3,112,560	2,880,408

200810	200811	200812	200901	200902	200903
196,800	942,960	2,788,280	3,351,120	2,885,120	2,887,840

Average

172,240	687,860	2,877,440	2,933,360	2,801,330	2,447,280

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[redacted]

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Note Account was re-billed by Power Billing February 2011

SEL SVC TO	DYS	P	R	ARTER	T	FRAN	KWH USE
2/24/2011	30	N	3	91	A	1510	519,600
1/26/2011	30	N	3	91	A	1510	154,300
12/27/2010	30	N	3	91	A	1510	183,000
11/23/2010	30	N	3	91	A	1510	103,800
10/25/2010	30	N	3	91	A	1510	43,046
9/24/2010	30	N	3	91	A	1510	3,900
8/25/2010	30	N	3	91	A	1510	4,700
7/27/2010	30	N	3	91	A	1510	4,500
6/25/2010	30	N	3	91	A	1510	5,800
5/26/2010	30	N	3	91	A	1510	10,000
4/27/2010	30	N	3	91	A	1510	4,900
3/26/2010	30	N	3	91	A	1510	464,000

201003	201004	201005	201006	201007	201008	201009
464,000	4,900	10,000	5,800	4,500	4,700	3,900

[redacted]

SEL SVC TO	DYS	P	KWH USE	ONP KWH	ACT D	ONP D	BIL D
2/15/2011	30	N	126,040	10,184	1,758	193	193
1/18/2011	30	N	123,120	9,807	2,134	154	154
12/14/2010	30	N	109,440	10,562	1,833	213	213
11/12/2010	30	N	115,799	6,821	1,919	144	144
10/14/2010	30	N	118,080	4,900	2,135	225	225
9/15/2010	30	N	108,240	2,544	1,491	84	84
8/16/2010	30	N	103,920	2,727	1,882	98	98
7/16/2010	30	N	95,280	2,300	1,880	94	94
6/16/2010	30	N	106,840	4,817	1,777	148	148
5/17/2010	30	N	81,360	22,198	1,811	1,849	1,849
4/16/2010	30	N	76,000	11,287	1,818	1,389	1,389
3/16/2010	30	N	76,720	9,272	1,877	293	293

201003	201004	201005	201006	201007	201008	201009
76,720	76,000	97,360	105,840	98,280	100,920	106,548

2/15/2011 Note use the combined kWh sales for the two 3/370 customers

[redacted]

SVC DATE	RM	DYS	T	C	Total KWH	ONPK KWH	OFFPK KWH	KWD
2/1/2011	2	29	A	B	6780	2099	4681	48
1/3/2011	1	33	A	B	6689	1674	5015	44
12/1/2010	12	33	A	B	7678	2083	5615	68
10/29/2010	11	29	A	B	5775	2139	3636	66
9/30/2010	10	30	A	B	5682	798	4904	36
8/31/2010	9	29	A	B	4183	568	3616	21
8/2/2010	8	32	A	B	5297	560	4737	21
7/1/2010	7	29	A	B	5005	861	4144	50
6/2/2010	6	30	A	B	5738	2389	3349	55
5/3/2010	5	31	A	B	6618	2647	3971	57
4/2/2010	4	29	A	B	7088	2138	4947	46
3/4/2010	3	29	A	B	7333	2001	5332	43

201003	201004	201005	201006	201007	201008	201009
7,333	7,088	6,618	5,738	5,005	5,297	4,183

[redacted]

SVC DATE	RM	DYS	T	C	Total KWH	ONPK KWH	OFFPK KWH	KWD
2/1/2011	2	29	A	B	13470	145	12325	1
1/3/2011	1	33	A	B	11280	146	11134	1
12/1/2010	12	33	A	B	22000	166	21844	1
10/29/2010	11	29	A	B	24120	157	23963	1
9/30/2010	10	30	L	B	32280	532	31728	1
8/31/2010	9	29	A	B	33170	55	33115	1
8/2/2010	8	32	A	B	37140	55	37085	1
7/1/2010	7	29	A	B	33560	54	33506	1
6/2/2010	6	30	A	B	34380	157	34223	1
5/3/2010	5	31	A	B	25380	162	25218	1
4/2/2010	4	29	A	B	13690	166	13682	66
3/4/2010	3	29	A	B	10120	145	9975	2

201003	201004	201005	201006	201007	201008	201009
10,120	13,690	25,380	34,380	33,560	37,140	33,170

3/370 Total

201003	201004	201005	201006	201007	201008	201009
17,453	20,978	32,198	40,118	38,565	42,437	37,353

2/265 Note use the combined kWh sales for the two 2/265 customers

[redacted]

2265

SVC DATE	RM	DYS	T	C	Total KWH	ONPK KWH	OFFPK KWH	KWD
2/8/2011	2	29	A	B	712,800		712,800	2,496
1/10/2011	1	33	A	B	82,800		82,800	448
12/8/2010	12	33	A	B	79,200		79,200	288
11/8/2010	11	29	A	B	106,800		106,800	480
10/7/2010	10	29	A	B	88,800		88,800	400
9/8/2010	9	30	A	B	103,200	9,137	94,063	213
8/9/2010	8	31	A	B	100,800	8,546	92,254	235
7/9/2010	7	30	A	B	84,000	7,728	76,272	149
6/9/2010	6	30	A	B	68,400	2,089	66,311	146
5/10/2010	5	31	A	B	63,600		63,600	391
4/9/2010	4	29	A	B	112,800		112,800	607
3/11/2010	3	29	A	B	52,800		52,800	323

201003	201004	201005	201006	201007	201008	201009
52,800	112,800	63,600	88,400	84,000	109,800	103,200

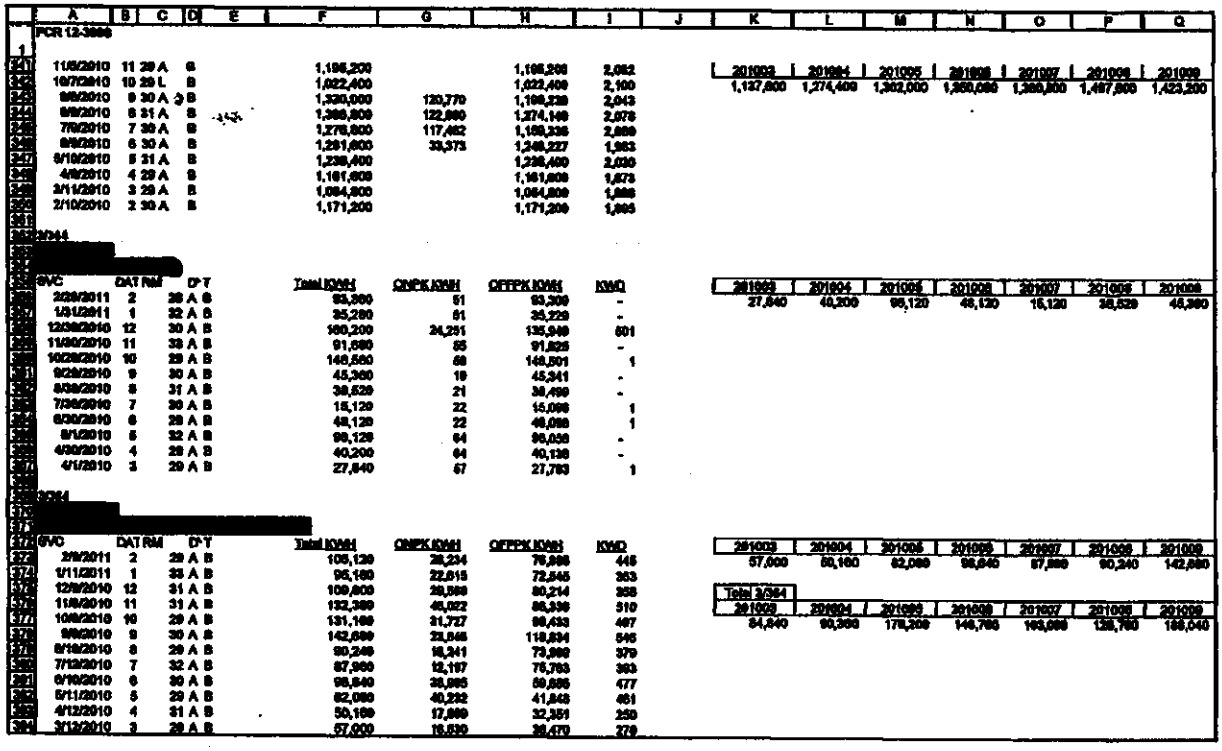
[redacted]

2265

SVC DATE	RM	DYS	T	C	Total KWH	ONPK KWH	OFFPK KWH	KWD
2/8/2011	2	29	A	B	1,075,200		1,075,200	1,797
1/10/2011	1	33	A	B	1,204,800		1,204,800	1,808
12/8/2010	12	33	A	B	1,219,200		1,219,200	1,849

201003	201004	201005	201006	201007	201008	201009
1,084,800	1,161,600	1,238,400	1,261,800	1,276,800	1,338,600	1,320,000

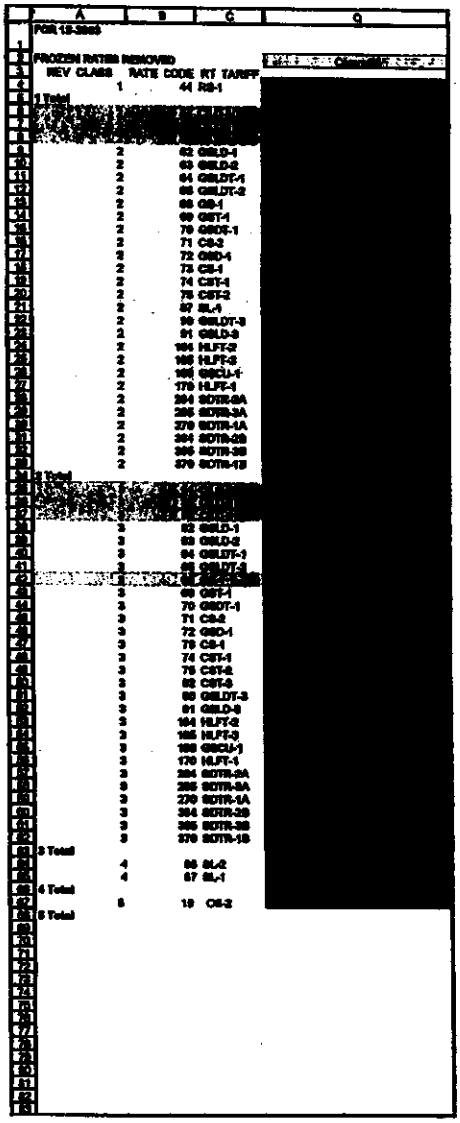
Total 2/265



	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	FCR 13-3886																
2											201003	201004	201005	201006	201007	201008	201009
3	11/8/2010	11	29	A	B	1,196,200		1,196,200	2,052		1,127,800	1,274,400	1,302,000	1,260,000	1,360,800	1,467,600	1,423,200
4	10/7/2010	10	29	L	B	1,022,400		1,022,400	2,100								
5	9/9/2010	9	30	A	B	1,330,000	120,770	1,198,230	2,043								
6	8/9/2010	8	31	A	B	1,396,800	122,880	1,274,148	2,078								
7	7/9/2010	7	30	A	B	1,276,800	117,462	1,159,338	2,089								
8	6/9/2010	6	30	A	B	1,281,600	33,373	1,248,227	1,963								
9	5/10/2010	5	31	A	B	1,238,400		1,238,400	2,030								
10	4/8/2010	4	29	A	B	1,161,600		1,161,600	1,673								
11	3/11/2010	3	29	A	B	1,084,800		1,084,800	1,888								
12	2/10/2010	2	30	A	B	1,171,200		1,171,200	1,885								
13																	
14	[redacted]																
15																	
16	[redacted]																
17	SVC	DAT	RM		D*T	Total KWH	ONPK KWH	OFFPK KWH	KWD		201003	201004	201005	201006	201007	201008	201009
18	2/28/2011	2		28	A B	93,360	61	93,300	-		27,840	40,200	99,120	46,120	15,120	38,520	46,560
19	1/31/2011	1		32	A B	35,280	61	35,220	-								
20	12/30/2010	12		30	A B	160,200	24,251	135,949	601								
21	11/30/2010	11		33	A B	91,680	55	91,625	-								
22	10/29/2010	10		29	A B	148,560	58	148,501	1								
23	9/29/2010	9		30	A B	45,360	19	45,341	-								
24	8/30/2010	8		31	A B	38,520	21	38,499	-								
25	7/30/2010	7		30	A B	15,120	22	15,098	1								
26	6/30/2010	6		29	A B	48,120	22	48,098	1								
27	5/1/2010	5		32	A B	98,128	64	98,058	-								
28	4/30/2010	4		28	A B	40,200	64	40,136	-								
29	4/1/2010	3		29	A B	27,840	57	27,783	1								
30																	
31	[redacted]																
32																	
33	[redacted]																
34	SVC	DAT	RM		D*T	Total KWH	ONPK KWH	OFFPK KWH	KWD		201003	201004	201005	201006	201007	201008	201009
35	2/9/2011	2		28	A B	105,120	28,234	76,886	445		57,000	80,160	82,080	96,840	87,880	90,240	142,680
36	1/11/2011	1		35	A B	95,160	22,915	72,245	353								
37	12/9/2010	12		31	A B	109,800	29,586	80,214	358		Total 3/364						
38	11/8/2010	11		31	A B	132,360	46,022	86,338	510		201003	201004	201005	201006	201007	201008	201009
39	10/8/2010	10		29	A B	131,160	31,727	99,433	467		84,840	120,360	178,200	144,760	103,080	138,760	188,040
40	9/8/2010	9		30	A B	142,680	23,846	118,834	546								
41	8/10/2010	8		29	A B	93,240	16,341	76,899	379								
42	7/12/2010	7		32	A B	87,960	12,197	75,763	363								
43	6/10/2010	6		30	A B	98,640	28,085	69,555	477								
44	5/11/2010	5		29	A B	82,080	40,232	41,848	461								
45	4/12/2010	4		31	A B	50,160	17,809	32,351	250								
46	3/12/2010	3		29	A B	57,000	18,530	38,470	279								

	A	B	C	L	M	N	O	P	Q
1	FCR 12-3000								
2									
3	FROZEN RATES REMOVED			September	October	November	December	Average	
4	REV_CLASS	RATE_CODE	RT_TARIFF	201109	201010	201011	201012		
5	1	44	RS-1	1,446	1,162	975	1,039	1,149	
6	1 Total								
7	2	62	GSLD-1	275,730	251,798	228,284	218,836	237,037	
8	2	63	GSLD-2	1,497,998	1,330,757	1,342,634	998,336	1,232,689	
9	2	64	GSLDT-1	460,867	343,732	334,789	316,202	338,398	
10	2	65	GSLDT-2	1,458,749	1,208,786	1,139,648	1,171,632	1,322,699	
11	2	66	GS-1	1,432	1,236	1,130	1,082	1,200	
12	2	69	GST-1	3,709	3,327	3,342	3,466	3,416	
13	2	70	GSDT-1	42,156	44,882	36,201	34,850	37,525	
14	2	71	CS-2	-	-	-	-	-	
15	2	72	GSD-1	22,270	19,360	18,073	17,232	18,908	
16	2	73	CS-1	339,074	337,429	278,307	254,331	321,843	
17	2	74	CST-1	808,126	660,760	649,755	540,985	649,617	
18	2	75	CST-2	1,883,200	748,200	1,086,800	1,061,400	1,095,899	
19	2	87	SL-1	1,434	1,430	1,444	1,438	1,438	
19	2	90	GSLDT-3	1,148,000	974,400	1,008,000	894,400	988,200	
20	2	91	GSLD-3	-	-	-	-	-	
21	2	164	HLFT-2	416,821	433,880	374,211	372,884	387,691	
22	2	165	HLFT-3	2,085,286	1,840,730	1,782,828	1,798,864	1,826,800	
23	2	169	GSCU-1	686	717	724	736	704	
24	2	170	HLFT-1	123,848	105,883	101,379	100,276	105,517	
25	2	264	SDTR-2A	236,321	230,302	205,234	189,833	199,364	
26	2	265	SDTR-3A	1,133,200	1,038,800	917,800	829,600	965,847	
27	2	270	SDTR-1A	43,948	38,191	36,086	30,855	34,481	
28	2	364	SDTR-2B	262,449	262,044	189,936	163,948	207,902	
29	2	365	SDTR-3B	843,286	764,200	646,900	570,200	656,137	
30	2	370	SDTR-1B	16,962	20,013	16,019	15,997	16,991	
31	2 Total								
32	3	62	GSLD-1	213,982	173,976	175,986	154,630	167,843	
33	3	63	GSLD-2	815,787	1,268,910	1,208,533	1,186,413	1,105,887	
34	3	64	GSLDT-1	536,607	458,975	442,539	432,711	479,699	
35	3	65	GSLDT-2	1,002,771	864,150	707,486	866,467	881,481	
36	3	69	GST-1	978	942	955	1,328	1,170	
37	3	70	GSDT-1	15,982	14,836	15,999	15,137	15,491	
38	3	71	CS-2	1,784,888	1,908,800	1,985,800	1,444,800	1,748,376	
39	3	72	GSD-1	17,288	16,560	15,078	16,038	16,999	
40	3	73	CS-1	202,880	175,500	178,906	158,348	191,229	
41	3	74	CST-1	343,940	288,780	272,780	278,886	302,332	
42	3	75	CST-2	1,404,888	1,008,000	616,000	670,400	977,097	
43	3	82	CST-3	882,188	778,880	626,000	338,000	722,178	
44	3	90	GSLDT-3	3,811,850	3,158,800	3,085,819	2,093,150	3,465,980	
45	3	91	GSLD-3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
46	3	164	HLFT-2	752,958	884,449	618,110	554,300	682,516	
47	3	165	HLFT-3	1,308,859	1,258,889	1,380,350	1,407,280	1,381,488	
48	3	169	GSCU-1	385	326	345	342	345	
49	3	170	HLFT-1	23,827	28,246	19,827	29,023	24,929	
50	3	264	SDTR-2A	412,827	379,480	316,920	288,420	338,763	
51	3	265	SDTR-3A	180,488	173,049	1,242,000	3,825,440	1,198,029	
52	3	270	SDTR-1A	18,782	14,823	14,514	14,575	14,188	
53	3	364	SDTR-2B	84,580	162,640	112,020	135,000	105,780	
54	3	365	SDTR-3B	108,248	116,088	115,796	109,440	109,880	
55	3	370	SDTR-1B	9,087	8,379	9,171	5,858	8,701	
56	3 Total								
57	4	86	SL-2	3,008	3,892	3,100	3,087	3,088	
58	4	87	SL-1	13,000	13,467	13,445	12,980	13,332	
59	4 Total								
60	5	19	OS-2	5,516	6,005	6,362	6,081	5,991	
61	5 Total								

	A	B	C	L	M	N	O	P	Q
1	PCR 13-3691								
2	FROZEN RATES REMOVED								
3	REV_CLASS	RATE_CODE	RT_TARIFF	September 201009	October 201010	November 201011	December 201012	Average	[redacted] Comment
4		1	44 RS-1	1,448	1,162	976	1,039	1,149	
5	1 Total								
6		2	62 GSLD-1	276,730	251,786	229,284	218,838	237,091	
7		2	63 GSLD-2	1,407,868	1,320,757	1,342,634	998,238	1,332,699	
8		2	64 GSLDT-1	400,867	343,732	334,788	318,302	366,698	
9		2	66 GSLDT-2	1,469,749	1,326,788	1,128,648	1,171,532	1,404,268	
10		2	68 GS-1	1,432	1,235	1,130	1,062	1,200	
11		2	69 GST-1	3,708	3,327	3,342	3,459	3,418	
12		2	70 GSDT-1	42,196	44,862	39,201	34,850	40,442	
13		2	71 CS-2	-	-	-	-	-	
14		2	72 GSO-1	22,270	19,260	18,073	17,232	18,949	
15		2	73 CS-1	338,074	337,429	278,307	254,331	299,976	
16		2	74 CST-1	606,128	660,780	549,758	540,996	646,617	
17		2	75 CST-2	1,053,280	1,046,280	765,960	781,400	943,199	
18		2	87 SL-1	1,434	1,430	1,444	1,438	1,436	
19		2	90 GSLDT-3	901,800	487,200	504,000	994,400	797,512	
20		2	91 GSLD-3	-	-	-	-	-	
21		2	164 HLFT-2	416,921	433,960	374,211	372,894	383,798	
22		2	165 HLFT-3	2,066,266	1,940,730	1,782,688	1,798,864	1,886,888	
23		2	166 GSCU-1	704	704	704	704	704	
24		2	170 HLFT-1	123,946	106,883	101,379	100,278	108,184	
25		2	264 SDTR-2A	230,321	230,362	205,234	169,833	193,364	
26		2	265 SDTR-3A	766,467	640,367	508,900	582,867	628,899	
27		2	270 SDTR-1A	43,948	30,191	35,056	30,855	34,481	
28		2	364 SDTR-2B	282,440	262,944	160,836	183,348	211,788	
29		2	365 SDTR-3B	643,298	679,200	670,900	670,200	666,167	
30		2	370 SDTR-1B	18,982	18,813	16,219	15,987	17,991	
31	2 Total								
32		3	62 GSLD-1	213,982	173,978	176,988	164,538	180,443	
33		3	63 GSLD-2	818,787	1,208,210	1,208,533	1,186,413	1,105,987	
34		3	64 GSLDT-1	636,007	488,978	442,539	432,711	521,816	
35		3	66 GSLDT-2	1,202,771	794,150	877,486	875,457	1,026,004	
36		3	68 GS-1					-	
37		3	69 GST-1	1,076	1,242	1,055	1,128	1,288	
38		3	70 GSDT-1	16,982	14,335	14,789	14,837	16,412	
39		3	71 CS-2	1,764,080	1,908,800	1,986,880	1,444,880	1,740,375	
40		3	72 GSO-1	17,939	15,880	15,078	15,028	15,983	
41		3	73 CS-1	202,880	176,800	178,986	156,346	181,229	
42		3	74 CST-1	343,840	286,780	272,750	276,885	308,832	
43		3	75 CST-2	1,404,880	1,088,000	916,000	870,400	977,867	
44		3	82 CST-3	882,109	770,000	625,080	328,800	722,176	
45		3	90 GSLDT-3	3,611,800	3,188,800	3,066,819	2,998,150	3,466,999	
46		3	91 GSLD-3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
47		3	164 HLFT-2	816,850	884,440	618,110	664,300	712,882	
48		3	165 HLFT-3	1,309,060	1,358,850	1,399,350	1,407,280	1,365,817	
49		3	166 GSCU-1	345	345	345	345	345	
50		3	170 HLFT-1	19,027	26,846	26,327	26,823	24,864	
51		3	264 SDTR-2A	412,827	379,480	316,920	325,428	362,938	
52		3	265 SDTR-3A	180,480	173,040	1,242,000	3,028,440	1,199,038	
53		3	270 SDTR-1A	16,462	14,723	14,814	14,575	15,893	
54		3	364 SDTR-2B	94,880	108,280	112,020	135,000	101,245	
55		3	365 SDTR-3B	108,240	116,080	115,798	109,440	108,890	
56		3	370 SDTR-1B	9,867	6,379	9,171	5,956	6,701	
57	3 Total								
58		4	86 SL-2	-	-	-	-	-	
59		4	87 SL-1	13,080	13,467	13,445	12,990	13,332	
60	4 Total								
61		5	19 OS-2	5,818	6,005	6,302	6,081	5,991	
62	5 Total								
63									
64									
65									



	A	B	C	Q
1	PGE 12-2005			
2				
3	FROZEN RATES REMOVED			
4	REV CLASS	RATE CODE	RT TARIFF	
5		1	44 RS-1	
6	1 Total			
7		2	62 GSLD-1	
8		2	63 GSLD-2	
9		2	64 GSLDT-1	
10		2	65 GSLDT-2	
11		2	66 GS-1	
12		2	69 GST-1	
13		2	70 GSDT-1	
14		2	71 CS-2	
15		2	72 GSD-1	
16		2	73 CS-1	
17		2	74 CST-1	
18		2	75 CST-2	
19		2	87 BL-1	
20		2	90 GSLDT-3	
21		2	91 GSLD-3	
22		2	164 HLFT-2	
23		2	165 HLFT-3	
24		2	166 GSCU-1	
25		2	170 HLFT-1	
26		2	264 SDTR-2A	
27		2	265 SDTR-3A	
28		2	270 SDTR-1A	
29		2	364 SDTR-2B	
30		2	365 SDTR-3B	
31		2	370 SDTR-1B	
32	2 Total			
33		3	62 GSLD-1	
34		3	63 GSLD-2	
35		3	64 GSLDT-1	
36		3	65 GSLDT-2	
37		3	69 GST-1	
38		3	70 GSDT-1	
39		3	71 CS-2	
40		3	72 GSD-1	
41		3	73 CS-1	
42		3	74 CST-1	
43		3	75 CST-2	
44		3	87 BL-1	
45		3	90 GSLDT-3	
46		3	91 GSLD-3	
47		3	164 HLFT-2	
48		3	165 HLFT-3	
49		3	166 GSCU-1	
50		3	170 HLFT-1	
51		3	264 SDTR-2A	
52		3	265 SDTR-3A	
53		3	270 SDTR-1A	
54		3	364 SDTR-2B	
55		3	365 SDTR-3B	
56		3	370 SDTR-1B	
57	3 Total			
58		4	86 BL-2	
59		4	87 BL-1	
60	4 Total			
61		5	19 CS-2	
62	5 Total			
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	A	B	C	D	E	F	G
1	**FCR 12-3908**						
2	**Forecast per Richard Feldman received 9/20/2011**						
3							
4	Year	Period	[redacted]				
5							
6	2010	1	1,046,844	1,046,844			
7	2010	2	940,800	940,800			
8	2010	3	991,200	991,200			
9	2010	4	1,100,400	1,100,400			
10	2010	5	1,243,200	1,243,200			
11	2010	6	1,503,600	1,503,600			
12	2010	7	1,545,600	1,545,600			
13	2010	8	1,428,000	1,428,000			
14	2010	9	1,520,400	1,520,400			
15	2010	10	1,344,000	1,344,000			
16	2010	11	1,209,600	1,209,600			
17	2010	12	1,033,200	1,033,200			
18	2011	1	974,400	974,400			
19	2011	2	999,600	999,600			
20	2011	3	1,150,800	1,150,800			
21	2011	4	1,125,600	1,125,600			
22	2011	5	1,184,400	1,184,400			
23	2011	6	1,503,600	1,503,600			
24	2011	7	1,545,600	1,545,600			
25	2011	8	1,428,000	1,428,000			
26	2011	9	1,520,400	1,520,400			
27	2011	10	1,344,000	1,344,000			
28	2011	11	1,209,600	1,209,600			
29	2011	12	1,033,200	1,033,200			
30	2012	1	974,400	974,400			
31	2012	2	999,600	999,600			
32	2012	3	1,150,800	1,150,800			
33	2012	4	1,125,600	1,125,600			
34	2012	5	1,184,400	1,184,400			
35	2012	6	1,503,600	1,503,600			
36	2012	7	1,545,600	1,545,600			
37	2012	8	1,428,000	1,428,000			
38	2012	9	1,520,400	1,520,400			
39	2012	10	1,344,000	1,344,000			
40	2012	11	1,209,600	1,209,600			
41	2012	12	1,033,200	1,033,200			
42	2013	1	974,400	974,400			
43	2013	2	999,600	999,600			
44	2013	3	1,150,800	1,150,800			

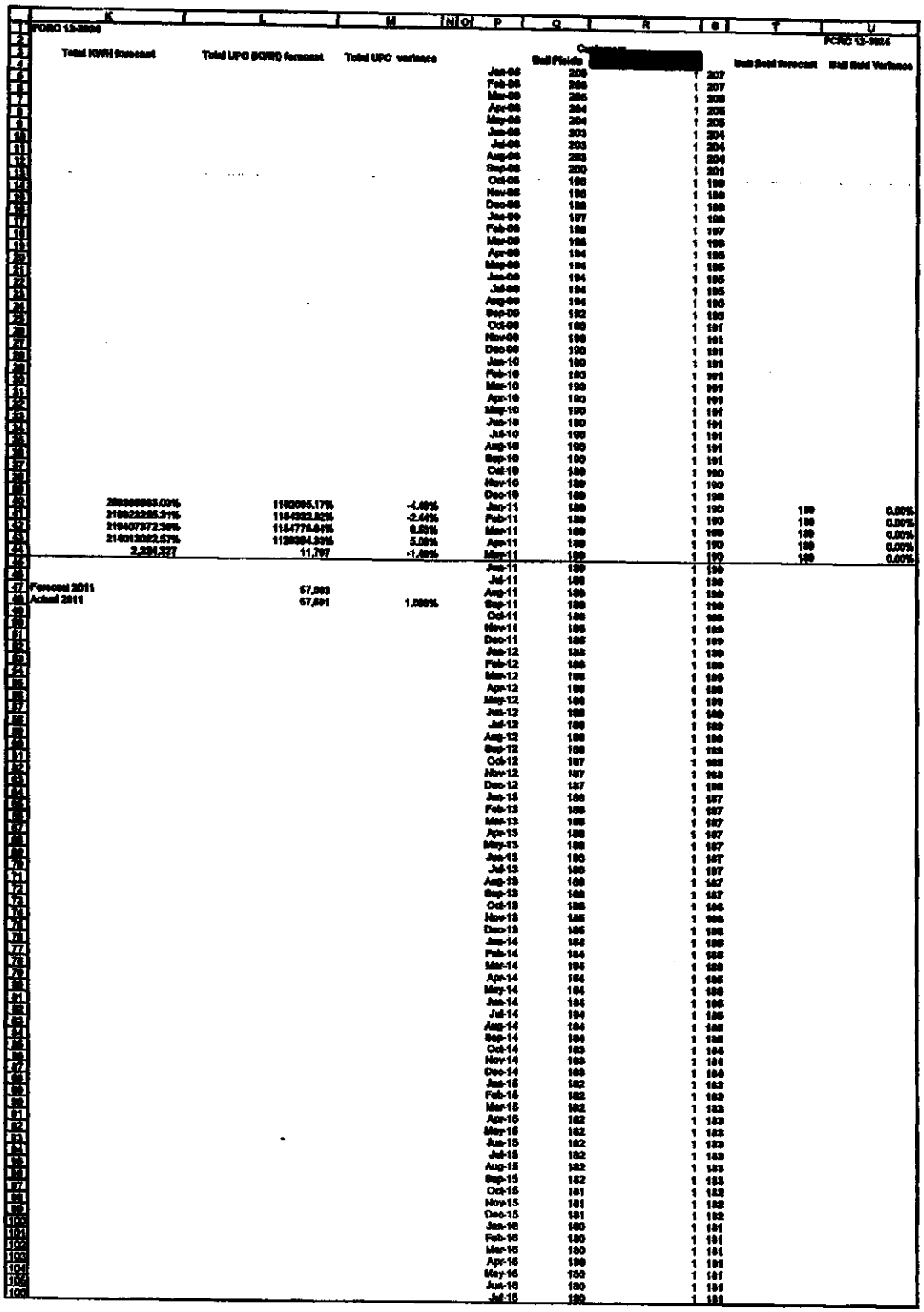
	A	B	C	D	E	F	G
90							
91							
92							
93	FCR 12-3908						
94							
95	[redacted]						
96							2011
97	January	February	March	April	May	June	July
98	974,400	999,600	1,150,800	1,125,600	1,184,400	1,444,800	1,545,600

FCR 12-3908

[redacted]

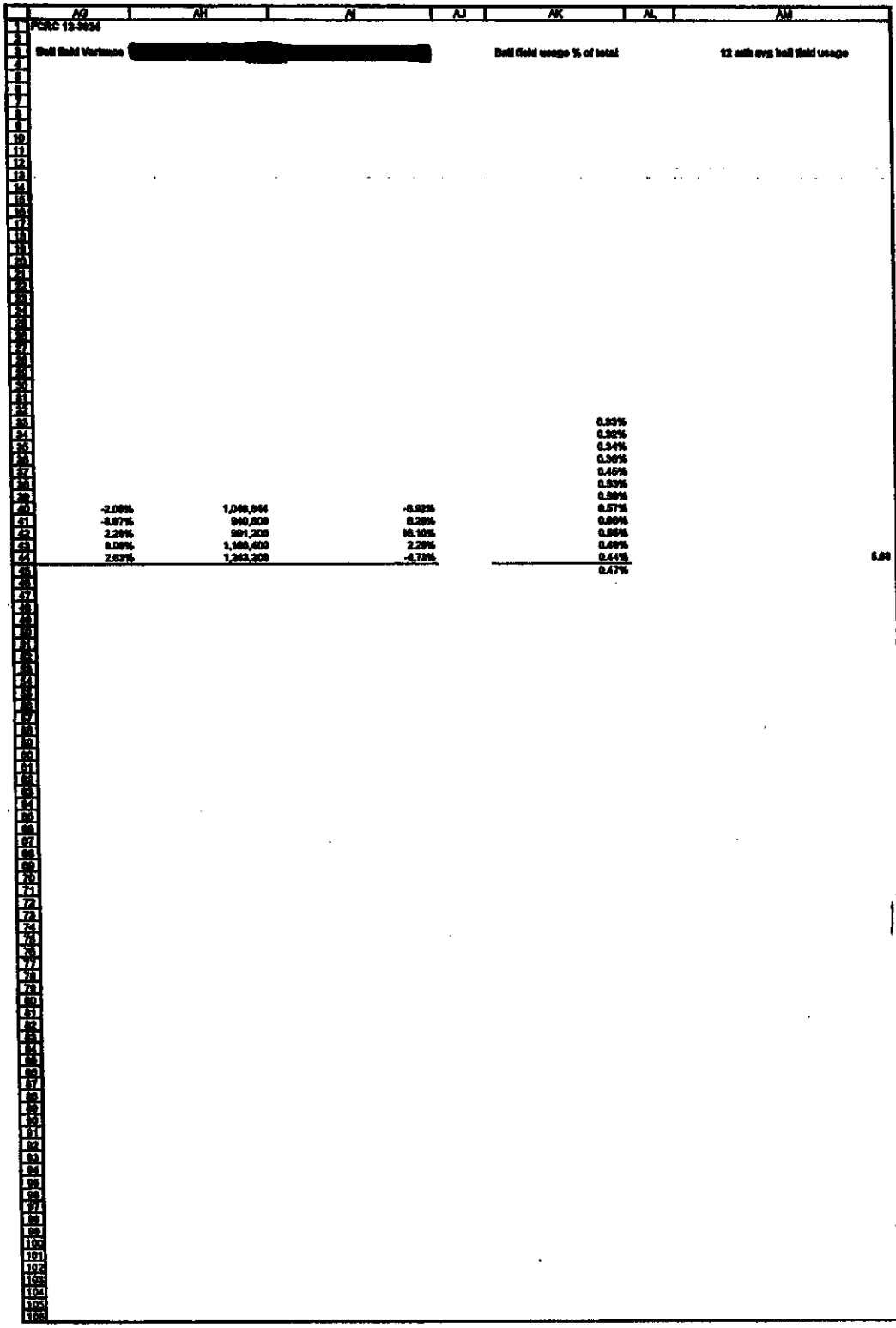
CC N (Y/N)	RQST BY				
SVC DATE	RM	DYS T C	ONPK KWH	OFFPK KWH	TOTAL KWH
2/26/2011	2	29	248,820	750,780	999,600
1/28/2011	1	30	239,454	734,946	974,400
12/29/2010	12	30	255,315	777,885	1,033,200
11/29/2010	11	33	289,209	920,391	1,209,600
10/27/2010	10	29	353,611	990,389	1,344,000
9/28/2010	9	32 A B	405,205	1,115,195	1,520,400
8/27/2010	8	29 A B	418,360	1,009,640	1,428,000
7/29/2010	7	30 A B	417,340	1,128,260	1,545,600
6/29/2010	6	32 A B	399,654	1,103,946	1,503,600
5/28/2010	5	29 A B	370,120	873,080	1,243,200
4/29/2010	4	29 A B	328,361	772,039	1,100,400
3/31/2010	3	29 A B	244,395	746,805	991,200
3/2/2010	2	29 A B	240,790	700,010	940,800
2/1/2010	1	33 A B	245,456	801,388	1,046,844
12/30/2009	12	35 A B	288,803	987,997	1,276,800
11/25/2009	11	29 A B	315,353	894,247	1,209,600
10/27/2009	10	29 A B	354,320	830,080	1,184,400
9/28/2009	9	32 A B	325,849	875,351	1,201,200
7/29/2009	7	30 A B	1,091,416	2,814,584	3,906,000
6/29/2009	6	31 A B	1,076,089	2,888,711	3,964,800
5/29/2009	5	30 A B	340,427	818,773	1,159,200
4/29/2009	4	29 A B	309,845	723,355	1,033,200
3/31/2009	3	29 A B	239,932	742,868	982,800
3/2/2009	2	31 A B	222,646	726,554	949,200
1/30/2009	1	31 A B	406,108	1,184,260	1,590,368
12/30/2008	12	35 A B	258,282	884,118	1,142,400
11/25/2008	11	29 A B	258,174	724,626	982,800
10/27/2008	10	31 A B	353,778	914,622	1,268,400
9/26/2008	9	30 A B	418,254	976,146	1,394,400
8/27/2008	8	29 A B	389,804	920,596	1,310,400

	A	B	C	D	E	F	G	H	I	J
1	PGRD 15-3624									
2										
3			Sales PGRD							
4		Bell Fields	[redacted]	Total KWH	Total MWH	Total UPC (GWH)	Bell Sold forecast	Bell Sold Variance	[redacted]	
5	Jan-08	1,088,711	1,688,000	6,780,311	6,780	27,779				
6	Feb-08	1,364,294	2,142,000	8,528,294	8,528	17,036				
7	Mar-08	1,380,882	2,291,200	9,001,882	9,002	17,486				
8	Apr-08	1,170,841	2,326,000	8,497,841	8,498	17,002				
9	May-08	1,887,488	2,419,000	8,488,828	8,487	17,806				
10	Jun-08	1,888,881	2,276,400	8,342,081	8,342	16,383				
11	Jul-08	983,086	1,411,200	5,394,386	5,394	11,737				
12	Aug-08	918,078	1,310,400	5,228,478	5,229	10,629				
13	Sep-08	1,887,308	1,384,400	5,481,708	5,482	12,947				
14	Oct-08	1,188,888	1,386,400	5,888,888	5,486	12,387				
15	Nov-08	1,387,408	982,800	5,388,208	5,388	11,488				
16	Dec-08	1,218,217	1,142,400	5,388,817	5,389	11,852				
17	Jan-09	1,133,885	1,580,388	5,724,324	5,724	13,758				
18	Feb-09	1,388,388	948,200	5,887,588	5,888	11,888				
19	Mar-09	1,388,288	982,800	5,223,088	5,223	11,842				
20	Apr-09	1,878,244	1,833,200	5,111,444	5,111	10,838				
21	May-09	1,812,287	1,188,300	5,171,487	5,171	11,136				
22	Jun-09	988,727	3,884,800	4,888,827	4,889	24,957				
23	Jul-09	908,182	3,888,000	4,888,182	4,888	24,853				
24	Aug-09	888,088	2,048,800	2,894,808	2,895	15,849				
25	Sep-09	1,848,287	1,281,200	2,947,287	2,947	11,844				
26	Oct-09	1,221,775	1,184,400	2,406,175	2,406	12,888				
27	Nov-09	1,278,282	1,288,880	2,888,882	2,888	13,016				
28	Dec-09	1,288,154	1,278,888	2,828,854	2,828	13,225				
29	Jan-10	1,052,838	1,848,844	2,888,883	2,188	10,883				
30	Feb-10	1,154,881	940,800	2,895,481	2,095	10,871				
31	Mar-10	1,187,278	981,288	2,188,578	2,189	11,301				
32	Apr-10	988,185	1,180,488	2,088,885	2,089	10,940				
33	May-10	973,328	1,243,288	2,278,889	2,217	11,886				
34	Jun-10	888,588	1,888,888	2,883,188	2,883	12,888				
35	Jul-10	884,828	1,848,888	2,888,828	2,888	13,087				
36	Aug-10	921,784	1,428,888	2,348,784	2,388	12,388				
37	Sep-10	1,845,881	1,828,488	2,888,281	2,888	13,428				
38	Oct-10	1,148,881	1,344,888	2,484,881	2,485	13,878				
39	Nov-10	1,308,127	1,288,888	2,417,727	2,418	12,725				
40	Dec-10	1,145,887	1,888,288	2,178,887	2,179	11,487				
41	Jan-11	1,888,832	974,488	2,888,882	2,888	10,328	1,847,137	-2.05%	1,048,844	-8.82%
42	Feb-11	1,148,888	988,888	2,138,888	2,148	11,881	1,382,433	-8.97%	848,888	6.28%
43	Mar-11	1,228,438	1,158,888	2,881,238	2,281	12,833	1,382,874	2.29%	881,288	18.10%
44	Apr-11	1,123,488	1,128,888	2,248,888	2,248	11,837	1,888,738	8.88%	1,188,488	2.28%
45	May-11	1,088,823	1,184,488	2,181,323	2,181	11,888	988,127	2.89%	1,248,288	-4.73%
46	Jun-11	942,288	1,888,888	2,448,888	2,448	12,874				
47	Jul-11	914,728	1,548,888	2,488,328	2,488	12,848				
48	Aug-11	878,272	1,428,888	2,288,272	2,288	12,138				
49	Sep-11	1,088,228	1,828,488	2,548,888	2,547	13,483				
50	Oct-11	1,188,823	1,344,888	2,884,823	2,884	13,288				
51	Nov-11	1,282,171	1,288,888	2,441,771	2,442	12,818				
52	Dec-11	1,178,781	1,888,288	2,288,881	2,218	11,888				
53	Jan-12	1,048,888	974,488	2,822,488	2,822	10,781				
54	Feb-12	1,382,788	988,888	2,282,388	2,282	11,882				
55	Mar-12	1,181,881	1,188,888	2,842,381	2,342	12,384				
56	Apr-12	1,047,873	1,128,888	2,172,873	2,173	11,488				
57	May-12	881,888	1,184,488	2,188,388	2,188	11,482				
58	Jun-12	888,881	1,828,888	2,884,881	2,424	12,828				
59	Jul-12	888,718	1,548,888	2,488,218	2,488	12,881				
60	Aug-12	881,113	1,428,888	2,288,113	2,288	12,218				
61	Sep-12	1,088,842	1,828,488	2,547,842	2,547	13,478				
62	Oct-12	1,181,781	1,344,888	2,588,781	2,888	13,828				
63	Nov-12	1,228,718	1,288,888	2,488,218	2,488	12,884				
64	Dec-12	1,177,812	1,883,388	2,211,812	2,211	11,781				
65	Jan-13	1,888,888	974,488	2,888,888	2,888	10,885				
66	Feb-13	1,147,388	988,888	2,148,888	2,147	11,481				
67	Mar-13	1,177,888	1,188,888	2,388,288	2,888	12,481				
68	Apr-13	1,088,881	1,128,888	2,182,381	2,182	11,883				
69	May-13	881,741	1,184,488	2,188,141	2,188	11,530				
70	Jun-13	888,873	1,888,888	2,428,873	2,430	12,882				
71	Jul-13	841,284	1,548,888	2,488,884	2,487	13,138				
72	Aug-13	878,483	1,428,888	2,307,483	2,307	12,238				
73	Sep-13	1,088,881	1,828,488	2,588,881	2,887	13,888				
74	Oct-13	1,188,884	1,344,888	2,478,884	2,488	13,333				
75	Nov-13	1,282,887	1,288,888	2,412,187	2,412	12,888				
76	Dec-13	1,148,188	1,883,388	2,181,388	2,181	11,728				
77	Jan-14	1,012,848	974,488	1,887,348	1,887	10,742				
78	Feb-14	1,148,884	988,888	2,148,284	2,148	11,888				
79	Mar-14	1,178,281	1,188,888	2,327,181	2,327	12,578				
80	Apr-14	1,048,821	1,128,888	2,173,821	2,174	11,748				
81	May-14	887,828	1,184,488	2,181,828	2,182	11,832				
82	Jun-14	911,881	1,503,888	2,415,181	2,415	13,858				
83	Jul-14	884,188	1,548,888	2,438,788	2,448	13,188				
84	Aug-14	882,478	1,428,888	2,288,478	2,288	12,381				
85	Sep-14	1,088,148	1,828,488	2,823,648	2,824	13,841				
86	Oct-14	1,128,888	1,344,888	2,472,888	2,474	13,448				
87	Nov-14	1,188,181	1,288,888	2,488,781	2,488	13,878				
88	Dec-14	1,144,827	1,888,288	2,177,827	2,178	11,888				
89	Jan-15	1,088,788	974,488	1,881,188	1,881	10,828				
90	Feb-15	1,138,448	988,888	2,138,348	2,138	11,883				
91	Mar-15	1,188,441	1,188,888	2,387,341	2,387	12,888				
92	Apr-15	1,021,848	1,128,888	2,147,148	2,147	11,733				
93	May-15	882,881	1,184,488	2,187,381	2,187	11,878				
94	Jun-15	888,748	1,503,888	2,488,348	2,488	13,133				
95	Jul-15	888,887	1,548,888	2,431,287	2,431	13,285				
96	Aug-15	855,585	1,428,888	2,283,585	2,284	12,478				
97	Sep-15	883,887	1,828,488	2,513,887	2,514	13,798				
98	Oct-15	1,117,788	1,344,888	2,481,788	2,482	13,838				
99	Nov-15	1,182,888	1,288,888	2,381,888	2,382	13,141				
100	Dec-15	1,131,885	1,053,288	2,188,885	2,188	11,888				
101	Jan-16	883,841	974,488	1,887,441	1,887	10,878				
102	Feb-16	1,117,484	988,888	2,117,884	2,117	11,888				
103	Mar-16	1,144,882	1,188,888	2,388,482	2,388	13,082				
104	Apr-16	1,012,824	1,128,888	2,138,824	2,139	11,815				
105	May-16	943,872	1,184,488	2,127,472	2,127	11,754				
106	Jun-16	882,578	1,503,888	2,388,178	2,388	13,238				
107	Jul-16	877,548	1,548,888	2,423,148	2,423	13,388				



	K	L	M	N	O	P	Q	R	S	T	U
1	PCRC 13-3924										PCRC 13-3924
2							Customer				
3	Total KWH forecast	Total UPC (KWH) forecast	Total UPC variance				Bull Fields	[redacted]		Bull Sold forecast	Bull Sold Variance
4						Jan-08	208		1 207		
5						Feb-08	208		1 207		
6						Mar-08	205		1 206		
7						Apr-08	204		1 205		
8						May-08	204		1 205		
9						Jun-08	203		1 204		
10						Jul-08	203		1 204		
11						Aug-08	203		1 204		
12						Sep-08	200		1 201		
13						Oct-08	199		1 198		
14						Nov-08	198		1 198		
15						Dec-08	198		1 198		
16						Jan-09	197		1 198		
17						Feb-09	196		1 197		
18						Mar-09	195		1 196		
19						Apr-09	194		1 195		
20						May-09	194		1 195		
21						Jun-09	194		1 195		
22						Jul-09	194		1 195		
23						Aug-09	194		1 195		
24						Sep-09	192		1 193		
25						Oct-09	190		1 191		
26						Nov-09	190		1 191		
27						Dec-09	190		1 191		
28						Jan-10	190		1 191		
29						Feb-10	190		1 191		
30						Mar-10	190		1 191		
31						Apr-10	190		1 191		
32						May-10	190		1 191		
33						Jun-10	190		1 191		
34						Jul-10	190		1 191		
35						Aug-10	190		1 191		
36						Sep-10	190		1 191		
37						Oct-10	189		1 190		
38						Nov-10	189		1 190		
39						Dec-10	189		1 190		
40	289999993.00%	1192065.17%	-4.46%			Jan-11	189		1 190	189	0.00%
41	219823288.31%	1164382.82%	-2.44%			Feb-11	189		1 190	189	0.00%
42	219407372.36%	1154778.64%	8.53%			Mar-11	189		1 190	189	0.00%
43	214013082.57%	1139384.29%	5.06%			Apr-11	189		1 190	189	0.00%
44	2,234,327	11,797	-1.46%			May-11	189		1 190	189	0.00%
45						Jun-11	189		1 190		
46						Jul-11	188		1 189		
47	Forecast 2011	57,893				Aug-11	188		1 189		
48	Actual 2011	57,891	1.000%			Sep-11	188		1 189		
49						Oct-11	188		1 189		
50						Nov-11	188		1 189		
51						Dec-11	188		1 189		
52						Jan-12	188		1 189		
53						Feb-12	188		1 189		
54						Mar-12	188		1 189		
55						Apr-12	188		1 189		
56						May-12	188		1 189		
57						Jun-12	188		1 189		
58						Jul-12	188		1 189		
59						Aug-12	188		1 189		
60						Sep-12	188		1 189		
61						Oct-12	187		1 188		
62						Nov-12	187		1 188		
63						Dec-12	187		1 188		
64						Jan-13	186		1 187		
65						Feb-13	186		1 187		
66						Mar-13	186		1 187		
67						Apr-13	186		1 187		
68						May-13	186		1 187		
69						Jun-13	186		1 187		
70						Jul-13	186		1 187		
71						Aug-13	186		1 187		
72						Sep-13	186		1 187		
73						Oct-13	185		1 186		
74						Nov-13	185		1 186		
75						Dec-13	185		1 186		
76						Jan-14	184		1 185		
77						Feb-14	184		1 185		
78						Mar-14	184		1 185		
79						Apr-14	184		1 185		
80						May-14	184		1 185		
81						Jun-14	184		1 185		
82						Jul-14	184		1 185		
83						Aug-14	184		1 185		
84						Sep-14	184		1 185		
85						Oct-14	183		1 184		
86						Nov-14	183		1 184		
87						Dec-14	183		1 184		
88						Jan-15	182		1 183		
89						Feb-15	182		1 183		
90						Mar-15	182		1 183		
91						Apr-15	182		1 183		
92						May-15	182		1 183		
93						Jun-15	182		1 183		
94						Jul-15	182		1 183		
95						Aug-15	182		1 183		
96						Sep-15	182		1 183		
97						Oct-15	181		1 182		
98						Nov-15	181		1 182		
99						Dec-15	181		1 182		
100						Jan-16	180		1 181		
101						Feb-16	180		1 181		
102						Mar-16	180		1 181		
103						Apr-16	180		1 181		
104						May-16	180		1 181		
105						Jun-16	180		1 181		
106						Jul-16	180		1 181		

	V	W	X	Y	ZAA	AB	AC	AD	AE	AF
1	DOR 15-3894									
2										
3	[redacted]		Total customer forecast	Total customer Variance		Usage per Customer (5/1/12)				
4							Ball Fields	[redacted]	Total UPC	Ball field forecast
5						1/1/2008	6,234	2,493,600		
6						2/1/2008	6,739	2,143,800		
7						3/1/2008	6,588	2,891,200		
8						4/1/2008	6,736	2,368,800		
9						5/1/2008	6,233	2,418,200		
10						6/1/2008	6,255	2,276,400		
11						7/1/2008	4,843	1,611,200		
12						8/1/2008	4,827	1,918,400		
13						9/1/2008	6,357	1,994,400		
14						10/1/2008	6,044	1,288,400		
15						11/1/2008	6,553	992,800		
16						12/1/2008	6,143	1,142,400		
17						1/1/2009	6,735	1,900,300		
18						2/1/2009	7,883	948,200		
19						3/1/2009	6,381	992,800		
20						4/1/2009	5,888	1,833,200		
21						5/1/2009	6,216	1,189,200		
22						6/1/2009	4,858	3,994,800		
23						7/1/2009	4,888	3,998,800		
24						8/1/2009	4,882	2,849,600		
25						9/1/2009	5,448	1,391,200		
26						10/1/2009	6,436	1,194,400		
27						11/1/2009	6,718	1,309,800		
28						12/1/2009	6,574	1,278,800		
29						1/1/2010	6,541	1,048,844		
30						2/1/2010	6,677	940,800		
31						3/1/2010	6,144	991,200		
32						4/1/2010	5,888	1,100,400		
33						5/1/2010	6,123	1,243,200		
34						6/1/2010	5,851	1,693,800	1,568,851	
35						7/1/2010	5,851	1,548,800	1,560,821	
36						8/1/2010	4,851	1,428,800	1,492,861	
37						9/1/2010	5,585	1,530,400	1,525,905	
38						10/1/2010	6,857	1,344,000	1,360,097	
39						11/1/2010	6,362	1,308,800	1,218,902	
40						12/1/2010	6,091	1,093,200	1,039,261	
41	1	0.00%	190	0.00%		1/1/2011	5,427	974,400	978,827	5,640
42	1	0.00%	190	0.00%		2/1/2011	6,852	988,800	1,005,832	6,827
43	1	0.00%	190	0.00%		3/1/2011	6,510	1,189,800	1,157,310	6,364
44	1	0.00%	190	0.00%		4/1/2011	5,944	1,125,800	1,131,544	5,501
45	1	0.00%	190	0.00%		5/1/2011	5,238	1,184,400	1,188,728	5,191
46						6/1/2011	4,866	1,668,800		
47						7/1/2011	4,840	1,548,800		
48		Forecast 2011	190			8/1/2011	4,847	1,428,800		
49		Actual 2011	190	0.000%		9/1/2011	5,490	1,530,400		
50						10/1/2011	6,170	1,344,000		
51						11/1/2011	6,554	1,308,800		
52						12/1/2011	6,389	1,093,200		
53						1/1/2012	5,575	974,400		
54						2/1/2012	6,867	988,800		
55						3/1/2012	6,336	1,189,800		
56						4/1/2012	5,570	1,125,800		
57						5/1/2012	5,223	1,184,400		
58						6/1/2012	4,898	1,668,800		
59						7/1/2012	4,838	1,548,800		
60						8/1/2012	4,857	1,428,800		
61						9/1/2012	5,461	1,530,400		
62						10/1/2012	6,213	1,344,000		
63						11/1/2012	6,565	1,308,800		
64						12/1/2012	6,298	1,093,200		
65						1/1/2013	5,514	974,400		
66						2/1/2013	6,168	988,800		
67						3/1/2013	6,331	1,189,800		
68						4/1/2013	5,579	1,125,800		
69						5/1/2013	5,224	1,184,400		
70						6/1/2013	4,979	1,668,800		
71						7/1/2013	4,860	1,548,800		
72						8/1/2013	4,728	1,428,800		
73						9/1/2013	5,485	1,530,400		
74						10/1/2013	6,149	1,344,000		
75						11/1/2013	6,589	1,308,800		
76						12/1/2013	6,288	1,093,200		
77						1/1/2014	5,606	974,400		
78						2/1/2014	6,189	988,800		
79						3/1/2014	6,393	1,189,800		
80						4/1/2014	5,668	1,125,800		
81						5/1/2014	5,256	1,184,400		
82						6/1/2014	4,884	1,668,800		
83						7/1/2014	4,869	1,548,800		
84						8/1/2014	4,857	1,428,800		
85						9/1/2014	5,492	1,530,400		
86						10/1/2014	6,174	1,344,000		
87						11/1/2014	6,598	1,308,800		
88						12/1/2014	6,256	1,093,200		
89						1/1/2015	5,501	974,400		
90						2/1/2015	6,255	988,800		
91						3/1/2015	6,364	1,189,800		
92						4/1/2015	5,613	1,125,800		
93						5/1/2015	5,235	1,184,400		
94						6/1/2015	4,944	1,668,800		
95						7/1/2015	4,886	1,548,800		
96						8/1/2015	4,701	1,428,800		
97						9/1/2015	5,498	1,530,400		
98						10/1/2015	6,176	1,344,000		
99						11/1/2015	6,530	1,308,800		
100						12/1/2015	6,283	1,093,200		
101						1/1/2016	5,517	974,400		
102						2/1/2016	6,298	988,800		
103						3/1/2016	6,399	1,189,800		
104						4/1/2016	5,627	1,125,800		
105						5/1/2016	5,239	1,184,400		
106						6/1/2016	4,959	1,668,800		
107						7/1/2016	4,875	1,548,800		



	AG	AH	AI	AJ	AK	AL	AM
1	PGEC 13-9934						
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3	Bell field Variance	[redacted]			Bell field usage % of total		12 mth avg bell field usage
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35					0.35%		
36					0.32%		
37					0.34%		
38					0.36%		
39					0.45%		
40					0.53%		
41					0.58%		
42	-2.09%	1,049,844	-5.02%		0.57%		
43	-5.97%	940,809	8.28%		0.60%		
44	2.29%	991,205	10.10%		0.56%		
45	8.09%	1,169,400	2.29%		0.49%		
46	2.83%	1,243,209	-6.73%		0.41%		5.69
47					0.47%		
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PEF's Response to Staff's 1st Set of Interrogatories (Nos. 1-5)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

RECEIVED
MAY 31 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

In re: Environmental cost recovery clause.	DOCKET NO. 120007-EI
	DATED: MAY 30, 2012

PROGRESS ENERGY FLORIDA'S RESPONSES TO
STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-5)

PROGRESS ENERGY FLORIDA, INC. (PEF), pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staff's First Set of Interrogatories (Nos. 1-5).

Responses

1. **Referring to page 4, lines 10 - 12, of West's testimony, please explain why a lower number of recertification tests were performed in 2011.**

   Response: Fewer tests were performed in 2011 because two units were undergoing required maintenance and not available for testing. Testing was subsequently successfully performed in 2012.

2. **Referring to page 5 of Exhibit WG-1 regarding Variance Report of O&M Activities, please explain in detail what caused the $45,744, or 36%, variance in the activity No. 7.4 CAIR/CAMR Crystal River-A&G.**

   Response: Activity No. 7.4 CAIR/CAMR Crystal River – A&G are O&M costs associated with the direct chargeable hours of employees who support the clean air projects. These costs are not included in PEF's Base Rates. The $45,774 or 36% variance is attributable to more time spent by employees in support of the clean air projects than expected in the 2011 Estimated/Actual Filing.

3. **Please refer to page 3 of C. Zeigler's testimony filed April 2, 2012, and Exhibit WG-1 for the following questions:**

   (a) **Does the "Substation System Program" discussed on lines 1 – 12 refer to (i) the Transmission Substation (Project No. 1 on page 6 of Exhibit WG-1); (ii), the Distribution Substation (Project No. 1a on page 6 of Exhibit WG-1); (iii), both the Transmission Substation (Project No. 1) and the Distribution Substation; or (iv) something else. If something else, please identify.**

   Response: The Substation System Program discussed on lines 1 – 12 refer to both Projects 1 and 1a, Transmission Substation and Distribution Substation, respectively.

(b) **Witness Zeigler testified (lines 4 – 5) that "[t]he project expenditure variance for the Substation System Program was $1,620,074 or 20% higher than projected." On page 5 of Exhibit WG-1, the Company indicated that the variance of Project No. 1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention (EIRPP) is 25%, and the variance of Project 1a Distribution Substation EIRPP is 11%. Please reconcile these numbers.**

Response: The Substation System Program includes environmental remediation costs of both transmission and distribution substation sites. Exhibit WG-1 splits remediation costs by these types of sites. Project No. 1 is remediation costs associated with transmission substation sites. Project No.1a is remediation costs related to distribution substation sites.

The 20% Substation System Program variance that Mr. Zeigler refers to on lines 4 -5 of his Direct Testimony filed April 2, 2012, is a combined variance of Project No. 1 and Project No.1a environmental remediation costs on Exhibit WG-1 page 5. This variance is derived by adding Projects No. 1 and Project No. 1a YTD Actual costs of $6,280,889 and $3,600,115, and, Estimated Actual costs of $5,009,189 and $3,251,741, and calculating a variance using the combined totals. The combined total of the YTD Actual amounts is $9,881,004. The combined total of the Estimated Actual amounts is $8,260,930. The variance between these totals is $1,620,074 or 20%.

Exhibit WG-1 shows the individual variances of Project No.1 and Project No.1a. The variance of Project No.1 of transmission substation environmental remediation costs is $1,271,700 or 25%. The variance of Project No. 1a of distribution substation environmental remediation costs is $348,374 or 11%.

(c) **Please break down the amount of $1,620,074 O&M cost variance (discussed on line 5) according to the major additional component activities and the associated costs incurred at each substation.**

Response: Environmental remediation activities at Central Florida, Kenneth and Wekiva substations primarily contributed to the O&M cost variance as shown below

Substation	Projected O&M Costs	Actual O&M Costs	Variance
Central Florida	$11,000	$1,332,410	$1,321,410
Kenneth	$889,000	$1,035,229	$146,229
Wekiva	$25,000	$160,093	$135,093

Central Florida is a very large substation with extensive contaminated soil which was discovered when remediation activities began in 2009. Remediation work was scaled back in 2010 to further delineate the site, and continue with soil and ground water monitoring. When 2011 cost projections were made, PEF estimated O&M costs of $11,000 for such assessment activities. During the course of 2011, however, a construction crew discovered additional contamination that needed to be excavated. Accordingly, the site was reprioritized and remediation crews returned to the site to remove this contaminated soil at a cost of $1,332,410.

The variances at the Kenneth and Wekiva substations were due to more soil contamination than initially anticipated at these sites.

(d) Did PEF perform all the activities involved in the Transmission Substation EIRPP, Distribution Substation EIRPP, and Distribution System EIRPP?

Response: No. PEF contracted with five vendors to perform various activities associated with the Substation Assessment and Remediation Action Plan (SARAP). One provides geological expertise, two provide environmental remediation, one provides safety oversight and one provides thermal treatments for disposal of contaminated soil, oily water and debris.

(e) If the response to (d) is no, did PEF contract out all, or a portion of, the activities?

Response: PEF contracted all activities associated with substation remediation at the onset of the SARAP program to comply with the Florida Department of Environmental Protection's (FDEP) Consent Order in 2003. PEF did not have the internal resources to remediate 279 substations that were identified for environmental remediation.

(f) If the response to (e) is yes, has PEF issued any requests for proposals in order to retain the best contractor?

Response: Yes. PEF sent out bid proposals for SARAP work. Contractors were chosen based on their expertise, cost, efficiency and safety record.

(g) If the response to (e) is yes, does PEF retain a same contractor to perform the activities every year?

Response: Yes. PEF contracted a geological firm in 2003 as a result of the FDEP's Consent Order. This firm is highly reputable in the industry, and developed PEF's SARAP which was approved by the FDEP. This firm has been an integral part of PEF's success in complying with and completing the Consent Order.

At the inception of the SARAP program in 2004, PEF had one remediation contractor and added another contractor in 2006. PEF also contracted for safety oversight over remediation work, and contracted with a thermal treatment facility for disposal of contaminated soil. PEF has kept the same contractors working on the program. These contractors have the expertise, knowledge, experience, and proven track record of providing remediation services in a safe and cost efficient manner. They have managed and followed all aspects of PEF's approved protocol with the FDEP. These contractors are familiar with PEF's policies and procedures, and continuously provide quality services in order to effectively meet PEF's SARAP obligations with the FDEP.

Please refer witness J. Swartz's testimony filed April 2, 2012, for questions 4 – 5.

4. **Referring to page 3, lines 11 – 13, please provide detailed explanations regarding the "$1,423,229 higher than expected costs for CAIR Crystal River Project 7.4-Energy." Please break down the amounts according to major components and activities of the project, and indicate the main causes associated with each cost increase.**

Response: Please see the attached worksheet.

5. **Please refer to line 15 on page 3 through line 2 on page 4 for the following questions:**

(a) What are the volumes (in tons) of gypsum that the FGDs at the Crystal River Power Plant (CR Plant) produced each year since the units were in-service?

Response:

Year	Tons
2009	1,702
2010	249,663
2011	450,309

Note: The tons in the chart above represent actual gypsum produced. The 478,792 tons referred to on Page 3, Line 21, of Jeff Swartz's April 2, 2012 Direct Testimony represent gysum sold or disposed of in 2011.

(b) What were the "expenses for gypsum removal" (line 20 on page 3) incurred in each of the past years?

	A	B	C
Year	Sales	Disposal	Transportation
2009	Note 1	Note 1	Note 1
2010	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]

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Note 1: PEF was in start-up of operating its scrubbers in 2009. Any gypsum that was produced as a by-product of the scrubber process was kept on PEF's storage pad and not sold that year. This gypsum was subsequently disposed of in 2010.

(c) What are the annual O&M costs associated with the disposal of the gypsum at the CR Plant In 2009, 2010 and 2011?

Response: O&M includes costs to load, transport and dispose of gypsum either to a third party or landfill facility. Please see the response to 5(b) above for transportation and disposal costs. With regard to loading costs, PEF has a combined contract for gypsum and limestone material handling services; however, gypsum handling costs are not separately itemized. These costs are estimated to be approximately $93,600 per year.

(d) Please provide a general explanation of how PEF disposed of the gypsum produced at the CR Plant.

Response: Gypsum is conveyed to a storage pad and stacked out utilizing a radial stacker. A loader operator loads each truck with approximately 24 to 25 tons of gypsum. The gypsum is then transported the third party landfill for disposal.

(e) For 2009, 2010, and 2011, please indicate in each year how many tons, and the percentage of the total amount, of gypsum produced at the CR Plant were disposed (i) in an on-site storage facility, (ii) in an off-site landfill owned by PEF, (iii) in a third-party landfill, or (iv) by selling in the market for beneficial use.

		A	B	C	D
Year	Tons	Sold	Percent Sold	Disposal (Third Party Landfill)	Percent Disposed
2009	1,702	[redacted]	[redacted]	[redacted]	[redacted]
2010	249,663	[redacted]	[redacted]	[redacted]	[redacted]
2011	450,309	[redacted]	[redacted]	[redacted]	[redacted]

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(f) What were the typical tipping fees PEF incurred in 2011 for disposal of gypsum?

Response: Please see the response to Question 5(b). Tipping fees are the disposal portion of gypsum removal expenses.

(g) What is the per mile cost per ton PEF incurred to transport gypsum to the disposal place(s)?

Response: The cost to transport gypsum to the landfill facility is approximately $0.10 to $0.12 per ton-mile based on assumed load per truck and route taken.

(h) Referring to line 2 on page 4, please provide a detailed explanation of how the revenues generated by selling gypsum were distributed.

Response: Revenues from the sale of gypsum, a by-product of the operation of the FGD systems, are credited to the ECRC. None of these revenues are in base rates.

(i) Referring to line 2 on page 4, please provide a detailed explanation of what caused the "suppressed market sales" and how PEF reacted on the changed market.

Response: The suppressed market sales were directly caused by the national economic recession. Impacted markets from the on-going recession include cement, concrete and wallboard. Specifically, cement consumption in the U.S. fell to a 40 year low and was off more than 50% in the state of Florida alone. As a result, several of the cement kilns operating in Florida either reduced their operations or idled them all together. Wallboard production is mainly affected by the construction of new homes and overall "housing starts" fell to their lowest level in 50 years. As such, many of the wallboard manufacturers reduced operations to single shifts and idled additional production lines to minimize production. Additionally, many new facilities slated for construction were put on hold or terminated. The wallboard industry is the largest consumer of synthetic gypsum. Consistent with CAIR compliance deadlines and PEF's approved compliance plan, the Crystal River FGD systems came on line in 2009 and 2010 in the midst of this economic downturn. As a result, PEF entered the market at the height of the recession. Demand for synthetic gypsum was the lowest seen in decades and production not only outweighed demand but was expected to continue increasing.

Despite the declining markets, Progress Energy successfully identified a partner who could utilize all of Crystal River's synthetic gypsum production for the long term. Additionally, Progress Energy was able to identify and capture market share in the wallboard, cement and agricultural markets to bridge the gap between the start-up of the Crystal River scrubbers and the implementation of the longer term solution in 2013. As

such, Progress Energy's aggressive marketing strategies realized sales of more that 70% of the plant production during that period.

(j) To whom has PEF sold gypsum produced at the CR Plant in the past?

Response:

[redacted]

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(k) Does PEF have a plan in place to more aggressively market gypsum in 2012 and beyond?

Response: PEF continually evaluates, develops and implements marketing strategies that take advantage of all available outlets for synthetic gypsum. Specifically, PEF employs a comprehensive multi-tiered approach utilizing a combination of independent third-party marketing groups and internal sales and marketing resources in an attempt to maximize the opportunities for beneficial reuse. Through continual involvement in targeted commercial outlets and on-going evaluations of developing industries, Progress Energy is able to effectively identify and evaluate existing and emerging end-use markets to provide suitable beneficial reuse options for the Crystal River Energy Complex.

(l) Is there an on-site gypsum storage facility at the CR Plant?

Response: The Crystal River Plant has a small area for temporary storage of gypsum.

(m) If the response to (l) is affirmative, what is the size (in acres) and capacity (in tons) of the facility?

Response: The total capacity of the temporary storage area is approximately 32,000 tons or 1.3 acres. The facility reaches design capacity in approximately two to three weeks of production.

(n) If the response to (l) is affirmative, when was the storage facility built? What were the capital costs associated with the construction? What are the annual O&M costs for operating the facility?

Response: The storage area was operational 11/26/09 at a capital cost of $18.5M. The O&M costs are described in response to question 5(c) above.

(o) If the response to (l) is affirmative, in how many years will the facility reach its limit? What is the designed life of the facility?

Response: The temporary storage area reaches its limits in two to three weeks. The designed storage limit is 32,000 tons.

(p) Does PEF own an off-site landfill for gypsum disposal?

Response: No, PEF does not own an off-site landfill for gypsum disposal.

(q) If the response to (p) is affirmative, what is the size (in acres) and capacity (in tons) of the facility, and how far is it from the CR Plant?

Response: N/A - PEF does not own an off-site landfill for gypsum disposal.

(r) If the response to (p) is affirmative, in how many years will the facility reach its limit? What is the designed life of the facility?

Response: N/A - PEF does no own an off-site landfill for gypsum disposal.

(s) Does PEF dispose of gypsum at a third-party landfill(s)? If so, how far away from the landfill is the CR Plant and what are the annual costs associated with the transportation of gypsum from the CR Plant to the landfill?

Response: Yes, PEF has contracted with a third-party landfill to allow for disposal of any material that can't be beneficially reused. The Crystal River Energy Complex is located approximately 140 miles from the landfill. Transportation costs are outlined in the response to Question 5(b).

DATED this 30th day of May, 2012.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko (Fla. Bar No. 855898)
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

Docket No. 120007-EI
Staff 1st Set of Interrogatories
PEF's Response to Interrogatory #4
Reagent/By Product Variances

		Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
Expense Dr (Cr)														
a. 5020011	Ammonia Expense	386,148	272,242	329,813	331,400	303,028	365,735	385,006	403,853	281,229	246,773	206,406	199,468	3,711,100
b. 5020012	Limestone Expense	347,053	280,410	306,652	294,359	321,811	303,283	358,144	427,482	465,306	428,874	184,857	308,094	4,026,325
c. 5020013	Dibasic Acid Expense	0	0	0	0	0	0	0	0	0	0	5,281	3,245	8,527
d. 5020003	Gypsum Disposal/Sale	127,623	221,100	406,513	357,711	(82,572)	1,313,296	667,844	702,767	1,001,032	772,739	11,908	50,020	5,549,981
e. 5020014	Bottom/Fly Ash Reagents Expense	0	0	42,969	29,210	528	8,532	328,181	8,439	465	14,754	10,422	10,498	453,999
f. Other		860,823	773,753	1,085,947	1,012,680	542,795	1,990,846	1,739,175	1,542,541	1,748,032	1,463,140	418,874	571,326	13,749,932
Net Expense (C)														

		Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
Expense Dr (Cr)														
a. 5020011	Ammonia Expense	386,148	272,242	329,813	331,400	303,028	365,735	283,486	284,753	259,983	249,223	146,852	242,673	3,455,337
b. 5020012	Limestone Expense	347,053	280,410	306,652	294,359	321,811	303,283	461,451	426,171	428,346	426,988	253,027	423,520	4,273,069
c. 5020013	Dibasic Acid Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
d. 5020003	Gypsum Disposal/Sale	127,623	221,100	406,513	357,711	(82,572)	1,313,296	539,835	422,070	429,330	424,798	75,000	182,354	4,417,058
e. 5020014	Bottom/Fly Ash Reagents Expense	0	0	42,969	29,210	528	8,532	16,667	16,667	16,667	16,667	16,667	16,667	181,239
f. Other		860,823	773,753	1,085,947	1,012,680	542,795	1,990,846	1,301,439	1,149,661	1,134,325	1,117,675	491,546	865,213	12,326,703
Net Expense (C)														

		January 11	February 11	March 11	April 11	May 11	June 11	July 11	August 11	September 11	October 11	November 11	December 11	End of Period Total	Variance Explanation
Expense Dr (Cr)															
a. 5020011	Ammonia Expense	0	0	0	0	0	0	101,520	119,099	21,245	(2,450)	59,554	(43,205)	255,763	1
b. 5020012	Limestone Expense	0	0	0	0	0	0	(103,308)	1,311	36,961	1,886	(68,170)	(115,426)	(246,745)	2
c. 5020013	Dibasic Acid Expense	0	0	0	0	0	0	0	0	0	0	5,281	3,245	8,527	3
d. 5020003	Gypsum Disposal/Sale	0	0	0	0	0	0	128,008	280,697	571,702	347,942	(63,092)	(132,334)	1,132,923	4
e. 5020014	Bottom/Fly Ash Reagents Expense	0	0	0	0	0	0	311,515	(8,227)	(16,202)	(1,913)	(6,244)	(6,168)	272,760	5
f. Other		0	0	0	0	0	0	437,736	392,880	613,707	345,465	(72,672)	(293,888)	1,423,229	
Net Expense (C)															

Variance Explanations

1 Ammonia variance primarily due to an increase in production offset by a decrease in the price of this reagent.

2 Limestone variance primarily due to burning lower sulfur coal later in the year that resulted in less limestone usage than originally forecasted offset slightly by higher capacity factors. Usage of limestone is dependent on the reactivity rate of the limestone itself and the SO2 content of the coal burned. Lower sulfur coal produces less SO2.

3 Variance due to trial use of dibasic acid that was not originally forecasted. This substance was used to test for positive impacts on scrubber efficiency.

4 Variance due to higher than budgeted volumes & higher expenses for gypsum removal. In 2011, actual production of gypsum was 478,792 tons compared to a projection of 430,890 tons. Actual production exceeded the projected amount primarily due to higher actual capacity factors for Crystal River Units 4 &5. In addition, increased production and suppressed market sales led to more gypsum being land filled than expected.

5 Variance primarily due to April through June costs that were improperly classified and accounted for in July 2011.

120007 Hearing Exhibits 00221

AFFIDAVIT

(STATE OF FLORIDA

COUNTY OF PINELLAS)

I hereby certify that on this 10th day of May, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared PATRICIA Q. WEST, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory number 1 from STAFF'S FIRST SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (NOs. 1 - 5) in Docket No. 120007-EI, and that the response is 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 10th day of May, 2012.

Patricia Q. West

Patricia Q. West

June C. Mooney

Notary Public
State of Florida

JUNE C. MOONEY
MY COMMISSION # DD806913
EXPIRES: September 18, 2012
1-800-3-NOTARY Fl. Notary Discount Assoc. Co.

My Commission Expires:

Sept. 18, 2012

AFFIDAVIT

(STATE OF FLORIDA

COUNTY OF Pinellas)

I hereby certify that on this 29 day of May, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared COREY ZEIGLER, ~~who is personally known to me,~~ and he acknowledged FL Drivers License before me that he provided the answers to interrogatory number(s) 3 from STAFF's FIRST SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (NO. 1) in Docket No. 120007-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 29 day of May, 2012.



Corey Zeigler

Notary Public
State of Florida

My Commission Expires:

2/27/14

12

PEF's Response to Staff's 2nd Set of Interrogatories (Nos. 6-16)

RECEIVED
JUN 29 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.

DOCKET NO. 120007-EI

DATED: JUNE 29, 2012

PROGRESS ENERGY FLORIDA'S RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 6-16)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Second Set of Interrogatories (Nos. 6-16):

RESPONSES

6. **Referring to schedule "Deferred Gain on Sales of Emissions Allowances (Project 5)," page 13 of WG-1, and its corresponding Excel worksheet "Form 42 8A p5" contained in a Company-provided Excel file "ECRC_2011_TU Monthly FINAL TU.xls" for the following questions.**

   a. **Please indicate the SO_2 allowance Auction proceeds, Annual NOx allowance purchases and Annual NOx allowance sales that occurred in each month of 2011.**

   b. **Please explain how the figure reported in column "April 11" on row "Line 1b 25401FL Auctioned SO_2 Allowance" was derived.**

PEF Response:

a. Please see attached response.

b. The $(1,704,491) of Auctioned SO2 Allowance in April 11 on Line 1b of WG-1 Form 42 8A p 5 of 16 was derived by subtracting April 2011 Allowance Amortization Expense of $(19,970) on Line 6b and subtracting $2,972 of allowance auction proceeds received from the EPA in April 2011 to the March 2011 Auctioned SO2 Allowance balance of $(1,721,489) on Line 1b.

7. **Referring to Line 1a Expenditures/Additions in schedule "CRYSTAL RIVER THERMAL DISCHARGE COMPLIANCE PROJECT-AFUDC-Base (Project 11.1)," page 23 of WG-1, please explain the nature and cause of (i) the negative $633,112 reported in column January11, and (ii) the negative $280,979 reported in column December 11.**

PEF Response:

The negative $633,112 in January 2011 on Line 1a of WG-1 Form 82 8A page 15 of 16 is a reversal of a July 2010 accounting adjustment.

The negative $280,979 in December 2011 on Line 1a of WG-1 Form 82 8A page 15 of 16 is the transfer of traveling screens from the Crystal River Discharge Compliance Project to Crystal River Units 1&2.

Please refer to witness W. Garrett's Exhibit WG-2 "Capital Programs Detail" filed April 2, 2012, for questions 8 -16.

8. **Referring to Line 1a Expenditures/Additions in schedule "ABOVE GROUND TANK SECONDARY CONTAINMENT-DeBARY CTs (Project 4.1g)," page 7 of WG-2, please explain the nature and cause of the negative $5,057 reported in column Nov-11.**

PEF Response:

The negative $5,057 in November 2011 on Line 1a of WG-2 page 7 of 22 is due to the allocation of a credit balance in the Corporate Stores account to Project 4.1g. Per CFR Electric Plant Instruction No. 4, "all overhead costs such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by third parties, law expenses, insurance, injuries and damages, pensions, taxes and interest shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit , both direct and overhead shall be deducted from the plant accounts at the time the property is retired." Throughout each month, construction overhead charges are accumulated in indirect capital projects. At month end, these charges are cleared from the indirect projects and allocated to target projects based on a predetermined allocation method. The target projects accumulate the costs that are capitalized to retirement units of property.

9. **Referring to Line 1a Expenditures/Additions and Line 1b Clearings to Plant in schedule "CRYSTAL RIVER 4 & 5 (Project 4.2a)," page 9 of WG-2, please explain the nature and cause of the negative $3,398 reported in column Mar-11.**

PEF Response:

The negative $3,398 in March 2011 on Line 1a and 1b of WG-2 page 9 of 22 is due the allocation of overhead charges to construction projects. See explanation provided in response to Question 8 above. This allocation was done in error and subsequently reversed in June 2011.

10. **Referring to Line 1a Expenditures/Additions and Line 1b Clearings to Plant in schedule "CAIR Crystal River AFUDC-UNIT 4 LNB/AH (Project 7.4b)," page 14 of WG-2, please explain the nature and cause of (i) the negative $59,852 reported in column Mar-11, and (ii) the negative $557,487 reported in column Apr-11.**

PEF Response:

The negative $59,852 in March 2011 and $557,487 in April 2011 on Line 1a and 1b of WG-2 page 14 of 22 are cost of removal (COR) adjustments. COR for CAIR projects are associated with base rate assets. As such, these costs are excluded from the ECRC plant in service amount and ECRC revenue requirements. The COR is the cost to remove base rate assets that were replaced with Clean Air assets. PEF estimated COR based on initial COR estimates. After removal work was completed, the vendor provided updated COR amounts and the original COR estimates were adjusted accordingly.

11. **Referring to Line 1a Expenditures/Additions and Line 1b Clearings to Plant in schedule "CAIR Crystal River AFUDC-Selective Catalytic Reduction (Project 7.4c)," page 15 of WG-2, please explain the nature and cause of (i) the negative $219,225 reported in column Apr-11, and (ii) the negative 527,543 reported in column Sep-11.**

PEF Response:

The negative $219,225 in April 2011 on Line 1a and 1b of WG-2 page 15 of 22 is due to COR adjustments. See the explanation provided in response to Question 10 above.

The negative $527,543 in September 2011 on Line 1a and 1b of WG-2 page 15 of 22 is due to a reversal of an accrual for expenditures that should have been recorded in Project 7.4d and a negotiated reduction in the contract price with a vendor for Project 7.4c.

12. **Referring to Line 1a Expenditures/Additions and Line 1b Clearings to Plant in schedule "CAIR Crystal River AFUDC-FGD Common (Project 7.4d)," page 15 of WG-2, please explain the nature and cause of the negative $792,224 reported in column 1 Feb-11.**

PEF Response:

The negative $792,224 in February 2011 on Line 1a and 1b of WG-2 page 15 of 22 is due to a COR adjustment. See the explanation provided in response to Question 10 above.

13. **Referring to Line 1a Expenditures/Additions and Line 1b Clearings to Plant in schedule "CAIR Crystal River AFUDC-Fuel Gas Desulfurization CR5 (Project 7.4f)," page 16 of WG-2, please explain the nature and cause of (i) the negative $6,684,218 reported in column 1 Feb-11, (ii) the negative $40,379 in column Aug-11, and (iii) the negative $39,947 in column Sep-11.**

PEF Response:

The negative $6,684,218 in January 2011 on Line 1 a and 1 b of WG-2 page 16 of 22 is due to the transfer of equipment (ID Fan) from Project 7.4f to CAIR Crystal River AFUDC – FGD Common Project 7.4d. PEF used different vendors to purchase and install the equipment. The purchase of the equipment was recorded in Project 7.4f. The install of the equipment was recorded in Project 7.4d. The equipment purchase was subsequently moved from Project 7.4f to Project 7.4d to properly account for it as Project 7.4d capital expenditures.

The negative $40,379 in August 2011 on Line 1a and 1b of WG-2 page 16 of 22 is due to the reversal of an accrual that should have been recorded in Project 7.4d.

The negative $39,947 in September 2011 on Line 1a and 1b of WG-2 page 16 of 22 is due to a reversal of an accrual for expenditures that should have been recorded in Project 7.4d and a negotiated reduction in the contract price with a vendor for Project 7.4f.

14. **Referring to Line 1a Expenditures/Additions and Line 1b Clearings to Plant in schedule "CAIR Crystal River AFUDC-CR4 SCR (Project 7.4i)," page 18 of WG-2, please explain the nature and cause of (i) the negative $457,019 reported in column 1 Feb-11, and (ii) the negative $842,067 reported in column Sep-11.**

PEF Response:

The negative $457,019 in February 2011 on Line 1a and 1 b of WG-2 page 18 of 22 is due to a COR adjustment. See the explanation provided in response to Question 10 above.

The negative $842,067 in September 2011 on Line 1a and 1b of WG-2 page 18 of 22 is due to a reversal of an accrual for expenditures that should have been recorded in Project 7.4d and a negotiated reduction in the contract price with a vendor for Project 7.4i.

15. **Referring to Line 1a Expenditures/Additions and Line 1b Clearings to Plant in schedule "CAIR Crystal River AFUDC-CR4 FGD (Project 7.4j)," page 18 of WG-2, please explain the nature and cause of (i) the negative $94,650 reported in column 1 Mar-11, (ii) the negative $4,510 reported in column Aug-11, and (iii) the negative $513,528 in column Sep-11.**

PEF Response:

The negative $94,650 in March 2011 on Line 1a and 1b of WG-2 page 18 of 22 is due to the reversal of an accrual that should have been recorded in Project 7.4d versus Project 7.4f.

The negative $4,510 in August 2011 on Line 1a and 1b of WG-2 page 18 of 22 is due to a credit for materials that were not used during construction that were put into plant inventory.

The negative $513,528 in September 2011 on Line 1a and 1b of WG-2 page 18 of 22 is due to a reversal of an accrual for expenditures that should have been recorded in Project 7.4d and a negotiated reduction in the contract price with a vendor for Project 7.4j.

16. **Referring to Line 1a Expenditures/Additions in schedule "CAIR Crystal River AFUDC-Bottom Ash (PH)/Fly Ash (Ammonia) (Project 7.4p)," page 21 of WG-2, please explain the nature and cause of the negative $11,534 in column Jan-11.**

PEF Response:

The negative $11,534 in January 2011 on Line 1a of WG-2 page 21 of 22 is due to the reversal of a labor accrual that should have been recorded in a non-ECRC project.

DATED this 29th day of June, 2012.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

AFFIDAVIT

(STATE OF FLORIDA

COUNTY OF Pinellas)

I hereby certify that on this 28th day of June, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared WILL GARRETT, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 6 through 16 from STAFF's SECOND SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (NOS. 6-16) in Docket No. 120007-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 28th day of June, 2012.

Will Garrett

SUZANNE H. MILLER
MY COMMISSION # DD 842[illegible]
EXPIRES: March 27, 2013
Bonded Thru Notary Public Underwriters

Suzanne H. Miller
Notary Public
State of Florida

My Commission Expires:

3/27/2013

SO2 & NOx Breakout
Year 2011

Docket 120007-EI
PEF's Responses to Staff's 2nd Set of Interrogatories
Attachment ROG-6

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	**Monthly Inventory Detail SO2 Emissions Allowances**												
2	Beginning Balance (1581001)	5,674,077.77	5,635,632.73	5,624,251.19	5,597,851.12	5,502,898.87	5,411,179.52	5,328,381.20	5,254,444.17	5,169,875.02	5,115,238.08	5,072,688.33	5,015,318.74
3	SO2 Emissions Expense (5090001)	38,445.04	11,381.54	70,664.31	94,952.25	91,719.35	82,798.32	73,937.03	84,569.15	54,636.94	42,549.75	57,369.59	37,129.28
4	Ending Balance (1581001) (Line 2 + Line 3)	5,635,632.73	5,624,251.19	5,553,586.88	5,502,898.87	5,411,179.52	5,328,381.20	5,254,444.17	5,169,875.02	5,115,238.08	5,072,688.33	5,015,318.74	4,978,189.46
6	**Monthly Inventory Detail Auctioned SO2 Allowances**												
7	Beginning Balance (25401FL)	(1,776,567.05)	(1,758,207.74)	(1,739,848.43)	(1,721,489.12)	(1,704,491.15)	(1,685,729.21)	(1,666,967.27)	(1,650,355.84)	(1,631,593.90)	(1,612,831.96)	(1,594,070.02)	(1,575,308.08)
8	SO2 Auction Proceeds	0.00	0.00	0.00	2,971.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	SO2 Amortization Expense (4074004)	18,359.31	18,359.31	18,359.31	19,969.85	18,761.94	18,761.94	18,761.94	18,761.94	18,761.94	18,761.94	18,761.94	18,761.94
10	Ending Balance (25401FL) (Line 7 - Line 8 + Line 9)	(1,758,207.74)	(1,739,848.43)	(1,721,489.12)	(1,704,491.15)	(1,685,729.21)	(1,666,967.27)	(1,648,205.33)	(1,631,593.90)	(1,612,831.96)	(1,594,070.02)	(1,575,308.08)	(1,556,546.14)
12	**Monthly Inventory Detail NOx Emissions Allowances**												
13	Beginning Balance (1581002)	22,715,427.11	27,399,003.02	27,239,126.87	27,000,013.15	26,422,639.57	25,824,183.12	25,196,279.54	24,539,791.24	23,890,029.64	23,280,760.86	22,939,684.71	22,548,429.64
14	NOX Purchases (Annual)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	NOx Emissions Expense (5090003)	316,424.09	159,876.15	239,113.72	577,373.58	598,456.45	627,903.58	656,488.30	649,761.40	609,268.98	341,076.15	391,255.07	282,653.55
16	Other - NOx Sales (Annual)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	Ending Balance (1581002) (Line 13 + Line 14 - Line 15 - Line 16)	22,399,003.02	27,239,126.87	27,000,013.15	26,422,639.57	25,824,183.12	25,196,279.54	24,539,791.24	23,890,029.84	23,280,760.66	22,939,684.71	22,548,429.64	22,265,776.09

Note> There were no annual and seasonal NOx purchases in 2011.

120007 Hearing Exhibits 00231

13

PEF's Response to Staff's 3rd Set of Interrogatories (Nos. 17-19)

REDACTED

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 120007-EI
	DATED: SEPTEMBER 13, 2012

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 17-19)

PROGRESS ENERGY FLORIDA, INC. (PEF), pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staff's First Set of Interrogatories (Nos. 17-19).

Responses

Please refer to witness P. West's testimony filed August 8, 2012, for questions 17 and 18.

17. Referring to project No. 11.1 discussed on pages 6 – 7:

a. Please elaborate on the phrase "reasonable storage costs."

Response: Under the current schedule for the Crystal River Unit 3 ("CR3") Extended Power Uprate (EPU), PEF does not need to commence cooling tower construction until April 2014 in order to complete it by April 2015 prior to the first summer of CR3 operation at power uprate conditions. As a result, PEF has additional time to evaluate evolving environmental regulatory requirements and impacts on the Company's generation operations before commencing with construction. Cooling tower storage costs incurred in 2012 are reasonable as they were necessary to secure and maintain the integrity of the cooling tower equipment.

Total 2012 expenditures for the cooling tower are estimated at approximately $880,000; of which 64% is allocated to ECRC and 36% is allocated to NCRC. Included in this amount is an invoice for cooling tower equipment for approximately $420,000 that was submitted to PEF by a vendor in November 2011 and paid in 2012. Because this invoice was not related to actual 2012 work, this was not considered as part of the explanation in Ms. West's testimony related to storage costs. Of the remaining $460,000, 64% or $300 thousand are storage costs allocated to ECRC. This amount includes actual storage costs of approximately $152,000 incurred January – June 2012 for activities such as: lay-down yard excavation; tent removal and set-up; install fencing around rail yard to protect cooling tower equipment, and trailer rental. The estimated July – December expenses of $148,000 are reflected in the total $563,727 costs on line 1 of Form 42 8E.

b. Is the variance of $563,727 capital expenditures solely related to the equipment storage?

Response: No. See response to 17a.

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FPSC-COMMISSION CLERK

c. Does PEF expect to incur the same level of cost every year until it commences construction work at the CR plant?

Response: Yes, approximately $210 thousand is estimated for 2013 for cooling tower storage costs.

18. Referring to page 8, lines 1 – 18 and page 11, lines 7 – 23:

a. When does PEF expect to start and to complete the Crystal River (CR) Units 4 and 5 carbon traps installation project?

Response: The installation of carbon traps on CR 4 & 5 began during the second quarter of 2012. Data collection began in June 2012 and continues to provide stack mercury (Hg) emission information. Carbon trap measurements for baseline data capture is expected to be completed at end of year 2012.

b. Within what period of time does PEF expect to incur the $1,250,000 capital expenditure associated with the project referenced in question 18a?

Response: Capital expenditure is expected to continue through the fourth quarter 2012. In addition to carbon trap testing, mercury profiling is planned for late third quarter 2012. Profiling will establish baseline mercury speciation at all points in the unit backpass to develop a profile that can be used to determine optimal Hg mitigation controls, if needed. Capital expenditures also include costs associated with performing mercury mitigation technology trials at CR 4 & 5, if needed.

c. What will be the total O&M costs associated with CR Units 4 and 5 MATS compliance for the period 2012 - 2013?

Response: The O&M costs have not yet been determined and will depend upon the results of the mercury emissions data collected.

d. Are the carbon traps are for measuring and trending the mercury emissions? Please explain.

Response: The carbon traps provide a means of measuring the average mercury emissions in the stack over a week-long period. The traps extract a slip stream of flue gas from the stack and collect mercury residual on carbon disks. The disks are removed and replaced on a weekly basis and are analyzed for total mercury capture. This measurement is then coupled with measured stack flow and carbon dioxide concentrations to derive an average pound/TBtu of mercury captured. Finally, this information is used to calculate a 30-day rolling average Hg emission for each unit.

e. Given the tight compliance deadline of the MATS, what will be potential control options to bring the CR Units 4 and 5 into compliance?

Response: Current measurements indicate that the mercury emissions from CR 4 & 5 appear to be within the limits established by MATS. If controls are required, options may include changes to unit operation, installation of mercury sorbent or other chemical injection systems or changes to existing equipment to reduce mercury concentrations.

19. Please refer to page 3, lines 13 – 24, of witness J. Swartz's testimony filed August 1, 2012, for the following questions.

a. Does PEF expect to produce fewer tons of gypsum in 2012 than it did in 2011?

Response: No, we expect to produce more gypsum in 2012 than 2011.

b. Please identify the tonnage of gypsum (1) produced in 2011, and (2) expected to be produced in 2012.

Response: 2011: 450,309 wet tons
2012: 463,239 wet tons

c. Please identify the tonnage of gypsum (1) sold to customers in 2011, and (2) expected to be sold to customers in 2012.

Response: 2011: [redacted] wet tons
2012: [redacted] wet tons

d. Please identify the factors that result in the "lower expenses than originally projected" for gypsum removal referenced at lines 18 – 19.

Response: Execution of additional contracts redirected incremental product originally budgeted for disposal to emerging markets. This resulted in increased beneficial reuse, reduced disposal costs and overall improvement in expenses.

e. Please identify the factors that result in the "increased customer sales" of gypsum referenced at line 19.

Response: See 19d and the response to Interrogatory No. 5(i) of Staff's First Set of Interrogatories.

DATED this 13th day of September, 2012.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko (Fla. Bar No. 855898)
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

AFFIDAVIT

(STATE OF FLORIDA

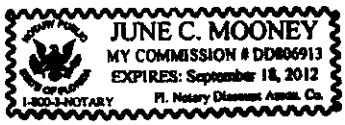
COUNTY OF PINELLAS)

I hereby certify that on this 31st day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared PATRICIA Q. WEST, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory number(s) 17 from STAFF's THIRD SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (NOS. 17-19) in Docket No. 120007-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 31st day of August, 2012.

Patricia Q. West

Patricia Q. West



June C. Mooney

Notary Public
State of Florida

My Commission Expires:

Sept. 18, 2012

AFFIDAVIT

(STATE OF FLORIDA

COUNTY OF PINELLAS)

I hereby certify that on this 29th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared PATRICIA Q. WEST, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory number(s) 18 from STAFF's THIRD SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (NOS. 17-19) in Docket No. 120007-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 29th day of August, 2012.

Patricia Q. West

JUNE C. MOONEY
MY COMMISSION # DD806913
EXPIRES: September 18, 2012
1-800-3-NOTARY Ft. Notary Discount Assoc. Co.

June C. Mooney

Notary Public
State of Florida

My Commission Expires:

Sept. 18, 2012

AFFIDAVIT

(STATE OF FLORIDA

COUNTY OF Pinellas)

I hereby certify that on this 29 day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JEFF SWARTZ, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 19 from STAFF's THIRD SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (NOS. 17-19) in Docket No. 120007-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 29 day of August, 2012.

LYNDA K. BATES
MY COMMISSION EXPIRES
February 27, 2014
#DD 936274
Bonded thru
Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

Jeff Swartz

Lynda K. Bates
Notary Public
State of Florida

My Commission Expires:
2-27-14

14

PEF's Response to Staff's 1st Production of Documents (No. 1)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

RECEIVED
JUN 29 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

In re: Environmental cost recovery clause.	DOCKET NO. 120007-EI
	DATED: JUNE 29, 2012

PROGRESS ENERGY FLORIDA'S RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.350, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's First Request for Production of Documents (No. 1):

RESPONSE

1. **Please refer to witness W. Garrett's Exhibit WG-1 "Calculation of the Final True-up Amount January 2011 through December 2011" and its corresponding Excel file "ECRC_2011_TU Monthly_FINAL TU.xls" filed April 2, 2012. Referring to schedule "Deferred Gain on Sales of Emissions Allowances (Project 5)," page 13 of WG-1, and its corresponding Excel worksheet "Form 42 8A p5" contained in the Excel file, please provide an update to the worksheet which (i) contains all the source data for the calculation of "Line 1b 25401FL Auctioned SO_2 Allowance" and (ii) maintains the links between each source data and the figures reported on row "Line 1b 25401FL Auctioned SO_2 Allowance."**

Response:

Please see attached worksheets.

SERVED this 29th day of June, 2012.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko, Esquire
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Working Capital Dr (Cr)														
	a. 1581001 SO_2 Emission Allowance Inventory	**5,674,079**	$5,635,633	$5,624,251	$5,597,851	$5,502,898	$5,411,179	$5,328,381	$5,254,444	$5,169,875	$5,115,238	$5,072,688	$5,015,318	$4,978,189	$4,978,189
	b. 25401FL Auctioned SO_2 Allowance	**(1,776,566)**	(1,758,207)	(1,739,848)	(1,721,489)	(1,704,491)	(1,685,729)	(1,666,967)	(1,650,355)	(1,631,593)	(1,612,831)	(1,594,069)	(1,575,307)	(1,556,546)	(1,556,546)
	c. 1581002 NOx Emission Allowance Inventory	**27,715,427**	27,399,003	27,239,127	27,000,013	26,422,640	25,824,183	25,196,280	24,539,791	23,890,030	23,280,761	22,939,685	22,548,430	22,265,776	22,265,776
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital	**31,612,939**	$31,276,429	$31,123,530	$30,876,375	$30,221,047	$29,549,634	$28,857,694	$28,143,880	$27,428,311	$26,783,167	$26,418,303	$25,988,440	$25,687,420	$25,687,420
3	Average Net Investment		$31,444,684	$31,199,979	$30,999,953	$30,548,711	$29,885,341	$29,203,664	$28,500,787	$27,786,095	$27,105,739	$26,600,735	$26,203,372	$25,837,930	
4	Return on Average Net Working Capital Balance (A)														
	a. Debt Component (Line 3 x 2.95% x 1/12) 2.95%		77,364	76,762	76,270	75,159	73,527	71,850	70,121	68,362	66,689	65,446	64,468	63,569	849,587
	b. Equity Component Grossed Up For Taxes 8.02%		210,245	208,609	207,271	204,254	199,819	195,261	190,561	185,783	181,234	177,857	175,200	172,757	2,308,851
5	Total Return Component (B)		$287,609	$285,371	$283,541	$279,413	$273,346	$267,111	$260,682	$254,145	$247,923	$243,303	$239,668	$236,326	3,158,438
6	Expense Dr (Cr)														
	a. 5090001 SO_2 Allowance Expense		38,445	11,382	26,400	94,952	91,719	82,796	73,937	84,569	54,637	42,550	57,370	37,129	695,889
	b. 4074004 Amortization Expense		(18,359)	(18,359)	(18,359)	(19,970)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(225,143)
	c. 5090003 NOx Allowance Expense		316,424	159,876	239,114	577,374	598,456	627,904	656,488	649,761	609,269	341,076	391,255	282,654	5,449,651
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)		336,510	152,899	247,154	652,356	671,414	691,940	711,663	715,569	645,144	364,864	429,863	301,021	5,920,396
8	Total System Recoverable Expenses (Lines 5 + 7)		$624,119	$438,270	$530,695	$931,769	$944,760	$959,051	$972,345	$969,714	$893,067	$608,167	$669,531	$537,347	9,078,834
	a. Recoverable costs allocated to Energy		624,119	438,270	530,695	931,769	944,760	959,051	972,345	969,714	893,067	608,167	669,531	537,347	9,078,834
	b. Recoverable costs allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor		0.96010	0.98220	0.99420	0.99600	0.98930	0.98770	0.98010	0.98430	0.97900	0.98110	0.98750	0.99230	
10	Demand Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)		$599,216	$430,468	$527,617	$928,042	$934,651	$947,255	$952,996	$954,489	$874,313	$596,673	$661,162	$533,209	8,940,091
12	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)		$ 599,216	$ 430,468	$ 527,617	$ 928,042	$ 934,651	$ 947,255	$ 952,996	$ 954,489	$ 874,313	$ 596,673	$ 661,162	$ 533,209	$ 8,940,091

Notes:
(A) Line 3 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc Tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

PROGRESS ENERGY FLORIDA, INC.
Regulatory Accounting
2011 - Account Reconciliation - 25401FL

Source> 25401FL 2010 Acct Recon Folder

(220,311.69) / 12 = (18,359.31) Monthly Amortization - Jan-Apr 2011

(150,095.53) / 8 = (18,761.94) Monthly Amortization - May-Dec 2011

	Beginning Balance	January	February	March	April	May	June	July	August	September	October	November	December
2011 Vintage Year Balance	(220,311.69)	(220,311.69)	(201,952.38)	(183,593.08)	(165,233.77)	(150,095.53)	(131,333.59)	(112,571.65)	(93,809.71)	(75,047.77)	(56,285.82)	(37,523.88)	(18,761.94)
Journal Entry - Auctioned SO2 Allowance Liability Amortization		18,359.31	18,359.31	18,359.31	19,969.85	18,761.94	18,761.94	18,761.94	18,761.94	18,761.94	18,761.94	18,761.94	18,761.94
2011 Vintage Year Emissions Auction Proceeds					(4,831.61)								
2011 Vintage Year Ending Balance		(201,952.38)	(183,593.08)	(165,233.77)	(150,095.53)	(131,333.59)	(112,571.65)	(93,809.71)	(75,047.77)	(56,285.82)	(37,523.88)	(18,761.94)	(0.00)
2012 Vintage Year Balance	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)	(512,026.02)
2013 Vintage Year Balance	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)	(473,550.91)
2014 Vintage Year Balance	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)	(332,795.21)
2015 Vintage Year Balance	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)	(234,317.48)
2016 Vintage Year Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
2017 Vintage Year Balance	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)	(3,565.70)
2018 Vintage Year Balance	(290.78)	-	-	-	(290.78)	(290.78)	(290.78)	(290.78)	(290.78)	(290.78)	(290.78)	(290.78)	(290.78)
TOTAL ENDING BALANCE		(1,758,207.74)	(1,739,848.44)	(1,721,489.13)	(1,706,641.67)	(1,687,879.73)	(1,669,117.79)	(1,650,355.85)	(1,631,593.91)	(1,612,831.96)	(1,594,070.02)	(1,575,308.08)	(1,556,546.14)
ORACLE General Ledger Balance from MOR		(1,758,207.74)	(1,739,848.43)	(1,721,489.12)	(1,704,491.15)	(1,685,729.21)	(1,666,967.27)	(1,650,355.84)	(1,631,593.90)	(1,612,831.96)	(1,594,070.02)	(1,575,308.08)	(1,556,546.14)
Variance (should be $0)		($0.00)	($0.00)	($0.01)	(2,150.52)	(2,150.52)	(2,150.52)	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)	-
					Note 1 2,150.51								

Note 1 As of 6/30/11, only $2,971.88 of $5,122.39 of SO2 auction proceeds were rec'd by PEF by EPA. This accounts for the $2,150.51 variance.

Adjustments to resolve difference:	Dr.	Cr.

C:\Documents and Settings\DWG\Local Settings\Temporary Internet Files\Content.Outlook\P2YBGYFM\[POD1_Response.xlsx]Acct Recon

C:\Documents and Settings\DWG\Local Settings\Temporary Internet Files\Content.Outlook\P2YBGYFM\[POD1_Response.xlsx]Acct Recon

120007 Hearing Exhibits 00243

MONTHLY Transaction Detail (for 25401FL account) SO2 AUCTIONED Allowances

Company Code	GL Batch Name	Project Level 2 Number	Line Description	Account Level 4 Code	Month/Year	Invoice Number	Voucher Number	Charge By Level 4 Code-Description	Charge To Level 4 Code-Description	Resource Type Lvl 2 Code-Descrip	Transaction Amount
60	60 OTOS723 ECRC Amortization S	0	ECRC Amortization 04/10	25401FL	Apr-11			000000 - UNSPECIFIED	000000 - UNSPECIFIED	000 - UNSPECIFIED	1,610.54
60	AR 18424 Receivables 4125206:	0	Journal Import Created	25401FL	Apr-11			000000 - UNSPECIFIED	000000 - UNSPECIFIED	000 - UNSPECIFIED	-2,971.88
60	PEF RE015 60 SO2 ALLOW AMORT:	0	ECRC Amortization	25401FL	Jan-11			000000 - UNSPECIFIED	000000 - UNSPECIFIED	000 - UNSPECIFIED	18,359.31
60	PEF RE015 60 SO2 ALLOW AMORT:	0	ECRC Amortization	25401FL	Feb-11			000000 - UNSPECIFIED	000000 - UNSPECIFIED	000 - UNSPECIFIED	18,359.31
60	PEF RE015 60 SO2 ALLOW AMORT:	0	ECRC Amortization	25401FL	Mar-11			000000 - UNSPECIFIED	000000 - UNSPECIFIED	000 - UNSPECIFIED	18,359.31
60	PEF RE015 60 SO2 ALLOW AMORT:	0	ECRC Amortization	25401FL	Apr-11			000000 - UNSPECIFIED	000000 - UNSPECIFIED	000 - UNSPECIFIED	18,359.31
60	PEF RE015 60 SO2 ALLOW AMORT:	0	ECRC Amortization	25401FL	May-11			000000 - UNSPECIFIED	000000 - UNSPECIFIED	000 - UNSPECIFIED	18,761.94
60	PEF RE015 60 SO2 ALLOW AMORT:	0	ECRC Amortization	25401FL	Jun-11			000000 - UNSPECIFIED	000000 - UNSPECIFIED	000 - UNSPECIFIED	18,761.94
		Sum:								Final	$109,599.78

120007 Hearing Exhibits 00244

PEF

SO2 EPA Auction Proceeds

Plant	2011	2018	Total
	453.40	27.29	
Anclote	480.07	28.89	989.65
Avon Park	19.65	1.18	20.83
	505.34	30.41	
	581.14	34.97	
	962.97	57.96	
CR	1,027.54	61.85	3,262.18
	28.07	1.69	
	28.07	1.69	
	28.07	1.69	
Debary	28.07	1.69	119.04
	2.81	0.17	
	29.48	1.77	
Turner	25.27	1.52	61.02
	16.84	1.01	
	19.65	1.18	
Higgins	18.25	1.10	58.03
	28.07	1.69	
	28.07	1.69	
	28.07	1.69	
Intercession C	28.07	1.69	119.04
	99.66	6.00	
	98.26	5.91	
Bartow	220.39	13.26	443.48
	9.83	0.59	
	9.83	0.59	
Suwannee	26.67	1.61	49.12
	4,831.61	290.78	5,122.39
chk			0.00

	4,831.61	Auction Proceeds Rec'd April 2011
/	12	
	402.63	Auction Proceeds Amortization
*	4	
	1,610.54	Total Jan-Apr Auction Proceeds Additional Amortization

Source> Distribution of Proceeds sheet - Steve LoConte

C:\Documents and Settings\DWG\Local Settings\Temporary Internet Files\Content.Outlook\P2YBGYFM\[POD1_Response.xlsx]Proceeds

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$7,312,132	$7,000,742	$6,834,722	$6,734,332	$6,640,697	$6,519,513	$6,351,199	$6,202,538	$6,061,926	$5,945,567	$5,847,546	$5,776,105	$5,674,079	$5,674,079
	b. 25401FL Auctioned SO_2 Allowance		($1,921,713)	($1,909,321)	($1,896,928)	($1,884,535)	($1,918,979)	($1,901,178)	($1,883,376)	($1,865,575)	($1,847,773)	($1,829,971)	($1,812,170)	($1,794,368)	($1,776,566)	($1,776,566)
	c. 1581002 NOX Emission Allowance Inventory		36,341,932	34,508,214	33,472,206	32,934,435	32,462,755	31,471,529	30,662,919	29,718,191	28,894,162	28,106,625	27,525,607	26,998,394	27,715,427	27,715,427
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0		
2	Total Working Capital		$41,732,351	39,599,635	38,410,000	37,784,232	37,184,472	36,089,865	35,130,742	34,055,154	33,108,315	32,222,220	31,560,983	30,980,131	31,612,939	31,612,939
3	Average Net Investment			40,665,993	39,004,818	38,097,116	37,484,352	36,637,168	35,610,303	34,592,948	33,581,735	32,665,268	31,891,602	31,270,557	31,296,535	
4	Return on Average Net Working Capital Balance															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		100,051	95,964	93,731	92,223	90,139	87,612	85,109	82,622	80,367	78,463	76,935	76,999	$1,040,215
	b. Equity Component Grossed Up For Taxes (B)	8.02%		271,900	260,793	254,724	250,627	244,963	238,097	231,295	224,534	218,406	213,233	209,081	209,254	2,826,907
5	Total Return Component (B)			371,951	356,757	348,455	342,850	335,102	325,709	316,404	307,156	298,773	291,696	286,016	286,253	3,867,122
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			311,390	166,020	100,390	93,636	121,183	168,314	148,661	140,612	116,360	98,020	71,441	102,026	1,638,053
	b. 4074004 Amortization Expense			($12,393)	($12,393)	($12,393)	($34,028)	($17,802)	($17,802)	($17,802)	($17,802)	($17,802)	($17,802)	($17,802)	($17,802)	($213,620)
	c. 5090003 Nox Allowance Expense			$2,208,719	806,008	537,771	471,680	997,525	1,188,611	944,728	824,028	787,538	588,518	527,213	917,967	$10,800,305
	d. Other			$0	0	0	0	0	0							
7	Net Expense (C)			2,507,716	959,635	625,768	531,288	1,100,907	1,339,123	1,075,588	946,839	886,096	668,736	580,852	1,002,192	12,224,739
8	Total System Recoverable Expenses (Lines 5 + 7)			2,879,667	1,316,392	974,223	874,138	1,436,009	1,664,832	1,391,992	1,253,995	1,184,869	960,432	866,868	1,288,445	16,091,861
	a. Recoverable costs allocated to Energy			2,879,667	1,316,392	974,223	874,138	1,436,009	1,664,832	1,391,992	1,253,995	1,184,869	960,432	866,868	1,288,445	16,091,861
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.97380	0.94550	0.94740	0.94960	0.96100	0.95710	0.95110	0.95380	0.95080	0.94900	0.96690	0.97260	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			2,804,219	1,244,649	922,979	830,081	1,380,005	1,593,411	1,323,923	1,196,060	1,126,573	911,450	838,175	1,253,141	15,424,667
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 2,804,219	$ 1,244,649	$ 922,979	$ 830,081	$ 1,380,005	$ 1,593,411	$ 1,323,923	$ 1,196,060	$ 1,126,573	$ 911,450	$ 838,175	$ 1,253,141	$ 15,424,667

Notes:
(A) Line 6 x 10.59% x 1/12. Based on ROE of 10.59%, weighted cost of equity component of capital structure of 4.73%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2009 rate case.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9.
(E) Line 8b x Line 10.

120007 Hearing Exhibits 00246

15

TECO's Response to Staff's 1st Set of Interrogatories (Nos. 1-5)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)	**DOCKET NO. 120007-EI**
	)	**FILED: May 30, 2012**
	)	

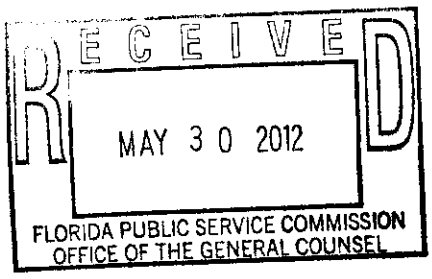
TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1-5)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 1-5) propounded and served on April 30, 2012, by the Florida Public Service Commission.



TAMPA ELECTRIC COMPANY
DOCKET NO. 120007-EI
INDEX TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1 – 5)

Number	Witness	Subject	Bates Stamped Page
1	Bryant	Referring to page 7, lines 4 – 7, please provide a detailed explanation of the relationship between the cogeneration purchases and the SO2 allowances used.	1
2	Bryant	Referring to page 7, lines 13 – 14, please break down the amount of $162,147 or 58% O&M variance of the Big Bend PM Minimization and Monitoring project by major component activities.	2
3	Bryant	Referring to page 7, lines 15 – 16, please elaborate what is meant by "facilitating best practices on fly ash system."	3
4	Carpinone	Referring to page 8, line 6 – 12: (a) For how many months does the EPA's extension cover? (b) Please explain why the extension created the need for additional outside services. (c) Please describe the activity included in "additional outside services?" (d) Did TECO use the existing service provider, or did TECO hire a new service provider for the work related to the EPA extension?	4
5	Bryant	Referring to line 13 on page 8 through line 2 on page 9: (a) Please break down the amount of $150,508 or 7.6% O&M variance of the Big Bend Unit 1 SCR project into two parts that relate to the increase in generating unit production, and to usage of the SO3 mitigation system. (lines 13 – 17 on page 8) (b) Please break down the amount of $221,267 or 17.3% O&M variance of the Big Bend Unit 2 SCR project into two parts that relate to the increase in generating unit production, and to usage of the SO3 mitigation system. (lines 18 – 22 on page 8) (c) Please break down the amount of $93,985 or 6.5% O&M variance of the Big Bend Unit 4 SCR project into two parts that relate to the increase in generating unit production and to usage of the SO3 mitigation system, respectively. (line 23 on page 8 – line 2 on page 9) (d) For each Big Bend generating unit, please describe	5

Number	Witness	Subject	Bates Stamped Page
		when and how often its associated SCR needs to run the SO3 mitigation system to reduce the effect of the side reaction of the SCR chemical reactions? (e) Was each of the SO3 mitigation systems installed at the same time as its associated SCR was placed in-service? If no, when was each SO3 mitigation system built and linked to its corresponding SCR?	

Howard Bryant
Manager, Rates

Paul Carpinone
Director, Environmental

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

The following questions relate to the testimony of H. Bryant, filed on April 2, 2012.

1. Referring to page 7, lines 4 – 7, please provide a detailed explanation of the relationship between the cogeneration purchases and the SO2 allowances used.

A. Tampa Electric purchases as-available energy from cogenerators in its service area. Based on the Tampa Electric generating unit avoided in lieu of the purchase, the as-available energy placed onto the company's system negates the consumption of company held SO_2 allowances since the use of system generation is avoided. Therefore, the market price value of these SO_2 allowances not consumed by Tampa Electric is paid to the cogenerator for the as-available energy delivered to the company.

2. Referring to page 7, lines 13 – 14, please break down the amount of $162,147 or 58% O&M variance of the Big Bend PM Minimization and Monitoring project by major component activities.

A. The major components creating the Big Bend PM Minimization variance were maintenance, inspections and oversight on the precipitator and fly ash systems on Big Bend generating units. Additionally, the extent of the work was not known until inspections of the units were completed and this occurred after the forecasted expenditures were made. The variance of $162,000 was comprised of $88,000 for the additional precipitator work and $74,000 for the additional fly ash operations work on Big Bend Units 1 through 4.

120007 Hearing Exhibits 00252

3. Referring to page 7, lines 15 – 16, please elaborate what is meant by "facilitating best practices on fly ash system."

A. Witness Bryant's reference to "facilitating best practices on fly ash system" refers to a systematic approach to maintenance of the fly ash system that optimizes the efficiency of the electrostatic precipitators and other ash handling equipment on Big Bend's four coal units. The approach begins with routine inspections and prioritization of observed deficiencies and as a result, maintenance is scheduled and completed as needed.

120007 Hearing Exhibits 00253

4. Referring to page 8, line 6 – 12:

(a) For how many months does the EPA's extension cover?

(b) Please explain why the extension created the need for additional outside services.

(c) Please describe the activity included in "additional outside services?"

(d) Did TECO use the existing service provider, or did TECO hire a new service provider for the work related to the EPA extension?

A. a. The EPA extended the comment period from July 11, 2011 to August 11, 2011.

b. During the one-month comment period extension, Tampa Electric continued to consult with outside legal counsel to study the impacts of the proposed 316(b) rule to multiple facilities owned and operated by Tampa Electric, as well as to assure that all areas of concern had been addressed in written comments submitted to EPA.

c. The additional outside services referenced in witness Bryant's testimony included utilizing legal counsel to evaluate the effect of the proposed rule on Tampa Electric facilities.

d. Tampa Electric utilized an existing service provider to continue to evaluate the potential impacts that the proposed 316(b) rule would have on Tampa Electric's facilities.

5. Referring to line 13 on page 8 through line 2 on page 9:

(a) Please break down the amount of $150,508 or 7.6% O&M variance of the Big Bend Unit 1 SCR project into two parts that relate to the increase in generating unit production, and to usage of the SO_3 mitigation system. (lines 13 – 17 on page 8)

(b) Please break down the amount of $221,267 or 17.3% O&M variance of the Big Bend Unit 2 SCR project into two parts that relate to the increase in generating unit production, and to usage of the SO_3 mitigation system. (lines 18 – 22 on page 8)

(c) Please break down the amount of $93,985 or 6.5% O&M variance of the Big Bend Unit 4 SCR project into two parts that relate to the increase in generating unit production and to usage of the SO_3 mitigation system, respectively. (line 23 on page 8 – line 2 on page 9)

(d) For each Big Bend generating unit, please describe when and how often its associated SCR needs to run the SO_3 mitigation system to reduce the effect of the side reaction of the SCR chemical reactions?

(e) Was each of the SO_3 mitigation systems installed at the same time as its associated SCR was placed in-service? If no, when was each SO_3 mitigation system built and linked to its corresponding SCR?

A. a. The variance of $150,508 or 7.6 percent was due primarily to the increased use of ammonia (approximately 8 percent) for the SO_3 mitigation system which was offset by a decrease in ammonia used in the SCR due to a decrease from projection in the unit's projected MWH production (less than 1 percent).

b. The variance of $221,267 or 17.3 percent was due primarily to the increased use of ammonia (approximately 8 percent) for the SO_3 mitigation system and an increase in ammonia used in the SCR due to an increase over projection in the unit's projected MWH production (approximately 9 percent).

120007 Hearing Exhibits 00255

c. The variance of $93,985 or 6.5 percent was due primarily to the increased use of ammonia (approximately ten percent) for the SO_3 mitigation system which was offset by a decrease in ammonia used in the SCR due to a decrease from production in the unit's projected MWH production (approximately 3.5 percent).

d. For 2011, Tampa Electric operated the SO_3 mitigation systems associated with all of Big Bend's units at full capacity. The amount of ammonia injected was based on the ongoing need for unit efficiency to meet environmental regulations.

e. Yes. Each unit's SO_3 mitigation system was installed at the same time as its associated SCR equipment.

120007 Hearing Exhibits 00256

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Howard Bryant who deposed and said that he is Manager - Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1 - 5) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 29th day of May, 2012.

Howard T. Bryant

Sworn to and subscribed before me this 29th day of May, 2012.

Denise Chichetto

Notary Public State of Florida
Denise Chichetto
My Commission EE 181752
Expires 03/21/2016

My Commission expires _____

16

TECO's Response to Staff's 2nd Set of Interrogatories (Nos. 6-12)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)	**DOCKET NO. 120007-EI**
	)	**FILED: September 17, 2012**
	)	

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 6-12)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 6-12) propounded and served on August 17, 2012, by the Florida Public Service Commission.

RECEIVED
SEP 18 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

TAMPA ELECTRIC COMPANY
DOCKET NO. 120007-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 6-12)

Number	Witness	Subject	Bates Stamped Page
6	Bryant	Referring to Line 10 "Adjustment to period True-Up Including Interest" on Form 42-2E, please provide a detailed explanation of the cause and nature of the $18,669 adjustment reported in column "January."	1
7	Bryant	Referring to "Project Big Bend Unit 1 SCR" reported on page 20 of Form 42-8E, filed August 1, 2012, and page 20 of Form 42-8A, filed April 1, 2012, please explain why the "Beginning of Period Amount" of 2012 reported on Form 42-8E, which is negative $3,686,991, does not tie with the "End of Period Total" of 2011 reported on Form 42-8A, which is negative $3,694,635.	2
8	Bryant	Please refer to "Project Big Bend Unit 1 SCR" reported on page 20 of Form 42-8E and its corresponding Excel file, worksheet "Form 42 8E p20," provided by TECO on August 8, 2012.	3
9	Bryant	Please refer to "Project Big Bend Unit 2 SCR" reported on page 21 of Form 42-8E and its corresponding Excel file, worksheet "Form 42 8E p21," provided by TECO on August 8, 2012.	4
10	Bryant	Referring to "Project Big Bend Unit 3 SCR" reported on page 22 of Form 42-8E, filed August 1, 2012, and page 22 of Form 42-8A, filed April 1, 2012, please explain why the "Beginning of Period Amount" of 2012 reported on Form 42-8E, which is $177,224, does not tie with the "End of Period Total" of 2011 reported on Form 42-8A, which is $0.	8
11	Bryant	Please refer to "Project Big Bend Unit 3 SCR" reported on page 22 of Form 42-8E and its corresponding Excel file, worksheet "Form 42 8E p22," provided by TECO on August 8, 2012. a. Referring to Line 3 "Less: Accumulated Depreciation" on page 22 of Form 42-8E, please explain why TECO used a different formula to calculate the dollar amount for April, while the formula used to calculate the dollar amounts for all other months is the same. b. Referring to Excel cell J21 in worksheet "Form 42 8E p22," it appears that TECO used the formula [-J32 + I21 - 1772977 - 634903 - 1220645 - 54485] to calculate the accumulated depreciation amount for April. (i) What does each of these numbers represent? (ii) Why were these numbers added into the calculation formula?	6

Number	Witness	Subject	Bates Stamped Page
12	Bryant	Please refer to "Project Big Bend Unit 4 SCR" reported on page 23 of Form 42-8E and its corresponding Excel file, worksheet "Form 42 8E p23," provided by TECO on August 8, 2012. a. Referring to Line 3 "Less: Accumulated Depreciation" on page 23 of Form 42-8E, please explain why TECO used a different formula to calculate the dollar amount for April, while the formula used to calculate the dollar amounts for all other months is the same. b. Referring to Excel cell J21 in worksheet "Form 42 8E p23," it appears that TECO used the formula [-J32 + I21 – 2495258 – 3927496 – 1428987 - 77578] to calculate the accumulated depreciation amount for April. (i) What does each of these numbers represent? (ii) Why were these numbers added into the calculation formula?	7

Howard Bryant
Manager, Rates

Tampa Electric Company
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The following questions relate to TECO's actual/estimated true-up schedules.

6. Referring to Line 10 "Adjustment to period True-Up Including Interest" on Form 42-2E, please provide a detailed explanation of the cause and nature of the $18,669 adjustment reported in column "January."

A. The nature of the $18,669 adjustment reported in column "January" was due to the following:

- A reversal of a $9.0 million depreciation reclassification made in June 2011, Form 42-8A, Page 20 that resulted in a ($7,400) adjustment.
- The identification of several specific FGD projects contained in line 1.a., Form 42-8A, Pages 1 and 11 that were actually earning AFUDC. These project related expenditures earning AFUDC were removed from Line 1.a., Expenditures, and from Line 4, CWIP, and moved to Line 1.d., Other. These expenditures are for tracking purposes only. Depreciation and Return will not be calculated until the projects go in-service. This resulted in a ($11,267) adjustment.
- A Big Bend Unit 3 SCR project was mislabeled as a PM Minimization project. Expenditures were moved from Form 42-8A, Page 14, PM Minimization to Form 42-8A, Page 22, Big Bend Unit 3 SCR. This transfer adjustment resulted in a net zero impact (absent rounding).
- The table below summarizes these adjustments.

Form 42 8A, Line 14. Total Jurisdictional Recoverable Costs

	Filing	True-up	Adjustment
Page 20	$ 11,663,591	$ 11,656,191	$ (7,400)
Page 1	739,258	738,636	(622)
Page 11	8,612,763	8,602,118	(10,645)
Page 14	1,060,869	1,056,898	(3,971)
Page 22	10,379,751	10,383,723	3,972
Total	$ 32,456,232	$ 32,437,566	$ (18,666)
Interest	3,842	3,839	(3)
Total Adjustment			**$ (18,669)**

7. Referring to "Project Big Bend Unit 1 SCR" reported on page 20 of Form 42-8E, filed August 1, 2012, and page 20 of Form 42-8A, filed April 1, 2012, please explain why the "Beginning of Period Amount" of 2012 reported on Form 42-8E, which is negative $3,686,991, does not tie with the "End of Period Total" of 2011 reported on Form 42-8A, which is negative $3,694,635.

A. The reason for the discrepancy between "End of Period Total" for the April 2, 2012 filing and the "Beginning of Period Amount" for the August 1 2012 filing is due to a reversal that was made on a $9.0 million depreciation schedule reclassification made in June 2011, Form 42-8A, Page 20. This project was originally assigned multiple sub-points during construction for the purpose of project management control of activities. At the end of the project, the multiple sub-points had to be reclassified to one sub-point in Power Plant, a fixed asset system utilized by Tampa Electric, in order to unitize all the project costs and to create the final assets. The reclassification in Power Plant should have been transparent to Accounting and no reclassification of depreciation schedules should have been made in June 2011.

8. Please refer to "Project Big Bend Unit 1 SCR" reported on page 20 of Form 42-8E and its corresponding Excel file, worksheet "Form 42 8E p20," provided by TECO on August 8, 2012.

   a. Referring to Line 3 "Less: Accumulated Depreciation" on page 20 of Form 42-8E, please explain why TECO used a different formula to calculate the dollar amount for April, while the formula used to calculate the dollar amounts for all other months is the same.

   b. Referring to Excel cell J21 in worksheet "Form 42 8E p20," it appears that TECO used the formula [-J32 + I21 - 855931 - 1428631 - 739965 - 40711] to calculate the accumulated depreciation amount for April.

      (i) What does each of these numbers represent?

      (ii) Why were these numbers added into the calculation formula?

A. a. Tampa Electric used a different calculation formula for the month of April due to corrective reserve transfers that were made per Order No. PSC-12-0175-PAA-EI, Docket No. 110131-EI, Page 4. The formula used in April 2011 reflects the required reserve transfers listed on Page 6 of the Commission Order.

   b. Form 42 8E page 20, Excel cell J21, reflects the required reserve transfers for the appropriate depreciation accounts associated with Big Bend Unit 1 SCR, referenced below.

      (i) The reserve transfers are:

Account number 31151	$ 855,931
Account number 31251	$1,428,631
Account number 31551	$ 739,965
Account number 31651	$ 40,711

      (ii) The numbers were added to the calculation formula to bring the accumulated depreciation into compliance with the aforementioned Commission Order.

9. Please refer to "Project Big Bend Unit 2 SCR" reported on page 21 of Form 42-8E and its corresponding Excel file, worksheet "Form 42 8E p21," provided by TECO on August 8, 2012.

a. Referring to Line 3 "Less: Accumulated Depreciation" on page 21 of Form 42-8E, please explain why TECO used a different formula to calculate the dollar amount for April, while the formula used to calculate the dollar amounts for all other months is the same.

b. Referring to Excel cell J21 in worksheet "Form 42 8E p21," it appears that TECO used the formula [-J32 + I21 – 1397838 – 1205165 – 850520 - 49334] to calculate the accumulated depreciation amount for April.

(i) What does each of these numbers represent?

(ii) Why were these numbers added into the calculation formula?

A. a. Tampa Electric used a different calculation formula for the month of April due to corrective reserve transfers that were made per Order No. PSC-12-0175-PAA-EI, Docket No. 110131-EI, Page 4. The formula used in April 2011 reflects the required reserve transfers listed on Page 6 of the Commission Order.

b. Form 42 8E page 21, Excel cell J21, reflects the required reserve transfers for the appropriate depreciation accounts associated with Big Bend Unit 2 SCR, referenced below.

(i) The reserve transfers are:

Account number 31152	$1,397,838
Account number 31252	$1,205,165
Account number 31552	$ 850,520
Account number 31652	$ 49,334

(ii) The numbers were added to the calculation formula to bring the accumulated depreciation into compliance with the aforementioned Commission Order.

10. Referring to "Project Big Bend Unit 3 SCR" reported on page 22 of Form 42-8E, filed August 1, 2012, and page 22 of Form 42-8A, filed April 1, 2012, please explain why the "Beginning of Period Amount" of 2012 reported on Form 42-8E, which is $177,224, does not tie with the "End of Period Total" of 2011 reported on Form 42-8A, which is $0.

A. The reason for the discrepancy between "End of Period Total" for the April 2, 2012 filing and the "Beginning of Period Amount" for the August 1, 2012 filing is due to a Big Bend Unit 3 SCR project that was mislabeled as a PM Minimization project. Expenditures were moved from Form 42-8A, Page 14, PM Minimization to Form 42-8A, Page 22, Big Bend Unit 3 SCR.

120007 Hearing Exhibits 00266

11. Please refer to "Project Big Bend Unit 3 SCR" reported on page 22 of Form 42-8E and its corresponding Excel file, worksheet "Form 42 8E p22," provided by TECO on August 8, 2012.

a. Referring to Line 3 "Less: Accumulated Depreciation" on page 22 of Form 42-8E, please explain why TECO used a different formula to calculate the dollar amount for April, while the formula used to calculate the dollar amounts for all other months is the same.

b. Referring to Excel cell J21 in worksheet "Form 42 8E p22," it appears that TECO used the formula [-J32 + I21 - 1772977 - 634903 - 1220645 - 54485] to calculate the accumulated depreciation amount for April.

(i) What does each of these numbers represent?

(ii) Why were these numbers added into the calculation formula?

A. a. Tampa Electric used a different calculation formula for the month of April due to corrective reserve transfers that were made per Order No. PSC-12-0175-PAA-EI, Docket No. 110131-EI, Page 4. The formula used in April 2011 reflects the required reserve transfers listed on Page 6 of the Commission Order.

b. Form 42 8E page 22 Excel cell J21, reflects the required reserve transfers for the appropriate depreciation accounts associated with Big Bend Unit 3 SCR, referenced below.

(i) The reserve transfers are:

Account number 31153	$1,772,977
Account number 31253	$ 634,903
Account number 31553	$1,220,645
Account number 31653	$ 54,485

(ii) The numbers were added to the calculation formula to bring the accumulated depreciation into compliance with the aforementioned Commission Order.

12. Please refer to "Project Big Bend Unit 4 SCR" reported on page 23 of Form 42-8E and its corresponding Excel file, worksheet "Form 42 8E p23," provided by TECO on August 8, 2012.

a. Referring to Line 3 "Less: Accumulated Depreciation" on page 23 of Form 42-8E, please explain why TECO used a different formula to calculate the dollar amount for April, while the formula used to calculate the dollar amounts for all other months is the same.

b. Referring to Excel cell J21 in worksheet "Form 42 8E p23," it appears that TECO used the formula [-J32 + I21 – 2495258 – 3927496 – 1428987 - 77578] to calculate the accumulated depreciation amount for April.

(i) What does each of these numbers represent?

(ii) Why were these numbers added into the calculation formula?

A. a. Tampa Electric used a different calculation formula for the month of April due to corrective reserve transfers that were made per Order No. PSC-12-0175-PAA-EI, Docket No. 110131-EI, Page 4. The formula used in April 2011 reflects the required reserve transfers listed on Page 6 of the Commission Order.

b. Form 42 8E page 23 Excel cell J21, reflects the required reserve transfers for the appropriate depreciation accounts associated with Big Bend Unit 4 SCR, referenced below.

(i) The reserve transfers are:

Account number 31154	($2,495,258)
Account number 31254	$3,927,496
Account number 31554	$1,428,987
Account number 31654	$ 77,578

(ii) The numbers were added to the calculation formula to bring the accumulated depreciation into compliance with the aforementioned Commission Order.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Howard Bryant who deposed and said that he is Manager - Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (Nos. 6 - 12) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 14th day of September, 2012.

Howard T. Bryant

Sworn to and subscribed before me this 14th day of September, 2012.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

17

TECO's Response to Staff's 3rd Set of Interrogatories (Nos. 13-15)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)	**DOCKET NO. 120007-EI**
	)	**FILED: October 8, 2012**
	)	

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD SET OF INTERROGATORIES (NOS. 13-15)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 13-15) propounded and served on September 18, 2012, by the Florida Public Service Commission.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120007-EI
INDEX TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 13-15)

Number	Witness	Subject	Bates Stamped Page
13	Bryant	Referring to Exhibit No. HTB-3 filed August 30, 2012, please explain why 1.0000000 was used as both the demand jurisdictional factor and the energy jurisdictional factor in the calculations of Form-2P, Form-3P, and Form-4P, pages 1 – 24.	1
14	Bryant	Please refer to "Project Big Bend Unit 3 Flue Gas Desulfurization Integration" reported on page 1 of Form 42-4P, filed August 30, 2012, and its corresponding Excel file, worksheet "Form 42 4P p1," provided by TECO on August 31, 2012. a. Referring to Line 4 "CWIP – Non-Interest Bearing" on page 1 of Form 42-4P, please explain why TECO used a different formula to calculate the dollar amount for May, while the formulas used to calculate the dollar amounts for all the other months are the same. b. Referring to Excel cell K22 in worksheet "Form 42 4P p1," it appears that TECO used the formula [J22+K15-K16+2073462+127010+2820960] to calculate the CWIP amount for May. (i) What do each of these numbers represent? (ii) Why were these numbers added into the calculation formula?	2
15	Bryant	Please refer to "Project Big Bend Units 1 and 2 FGD" reported on page 9 of Form 42-4P and its corresponding Excel file, worksheet "Form 42 4P p9," provided by TECO on August 31, 2012. a. Referring to Line 4 "CWIP – Non-Interest Bearing" on page 9 of Form 42-4P, please explain why TECO used a different formula to calculate the dollar amounts for October and December, while the formulas used to calculate the dollar amounts for all the other months are the same. b. Referring to Excel cell P22 in worksheet "Form 42 4P p21," it appears that TECO used the formula [+P15+O22-P16+571098+70186+1110000] to calculate the accumulated depreciation amount for October.	4

Number	Witness	Subject	Bates Stamped Page
		(i) What do each of these numbers represent? (ii) Why were these numbers added into the calculation formula?	

Howard Bryant
Manager, Rates

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

13. Referring to Exhibit No. HTB-3 filed August 30, 2012, please explain why 1.0000000 was used as both the demand jurisdictional factor and the energy jurisdictional factor in the calculations of Form-2P, Form-3P, and Form-4P, pages 1 – 24.

A. Tampa Electric used a demand and energy jurisdictional factor of 1.0000000 due to the company not having any wholesale power sales contracts for 2013. The current wholesale power sales contract for Tampa Electric expires on December 31, 2012.

120007 Hearing Exhibits 00274

14. Please refer to "Project Big Bend Unit 3 Flue Gas Desulfurization Integration" reported on page 1 of Form 42-4P, filed August 30, 2012, and its corresponding Excel file, worksheet "Form 42 4P p1," provided by TECO on August 31, 2012.

a. Referring to Line 4 "CWIP – Non-Interest Bearing" on page 1 of Form 42-4P, please explain why TECO used a different formula to calculate the dollar amount for May, while the formulas used to calculate the dollar amounts for all the other months are the same.

b. Referring to Excel cell K22 in worksheet "Form 42 4P p1," it appears that TECO used the formula [J22+K15-K16+2073462+127010+2820960] to calculate the CWIP amount for May.

(i) What do each of these numbers represent?

(ii) Why were these numbers added into the calculation formula?

A.

a. Tampa Electric's Big Bend Unit 3 Flue Gas Desulfurization Integration Project is experiencing construction activities with expenditures of the magnitude appropriate for AFUDC treatment. The expenditures for the construction activity are projected to be placed in-service May 2013. Therefore, an entry in Line 1.b. "Clearing to Plant" must be made indicating the amount to be added to Line 2 "Plant-in Service/Depreciation Base" for May 2013. Once the entry to "Clearing to Plant" was made, it created a negative balance in Line 4 "CWIP – Non-Interest Bearing" for May in cell K22. In order for cell K22 to reflect a zero balance due to AFUDC treatment of project expenditures, the formula in cell K22 had to be changed to reflect a zero balance since no CWIP consideration could be made. Therefore, the formula for May accurately reflects the zero balance in CWIP at the time the project is projected to be placed in-service. The specific tracking of the project expenditures during the time of construction has been identified in Line 1.c. "Other" with an explanation provided in Note G.

b. (i) The numbers in the calculation for cell K22 in worksheet "Form 42-4P, p 1" represent the following expenditures:

$127,010 Expenditures for Nov-Dec 2011;
$2,073,462 Expenditures for Jan-Dec 2012;
$2,820,960 Expenditures for Jan-Apr 2013.

(ii) The above-referenced numbers were added to the calculation in May 2013 per projected in-service date. As previously stated above, these expenditures were earning AFUDC and therefore not included in CWIP.

120007 Hearing Exhibits 00276

15. Please refer to "Project Big Bend Units 1 and 2 FGD" reported on page 9 of Form 42-4P and its corresponding Excel file, worksheet "Form 42 4P p9," provided by TECO on August 31, 2012.

a. Referring to Line 4 "CWIP – Non-Interest Bearing" on page 9 of Form 42-4P, please explain why TECO used a different formula to calculate the dollar amounts for October and December, while the formulas used to calculate the dollar amounts for all the other months are the same.

b. Referring to Excel cell P22 in worksheet "Form 42 4P p21," it appears that TECO used the formula [+P15+O22-P16+571098+70186+1110000] to calculate the accumulated depreciation amount for October.

(i) What does each of these numbers represent?

(ii) Why were these numbers added into the calculation formula?

A.

a. Tampa Electric's Big Bend Units 1 and 2 FGD Integration Project is experiencing construction activities with expenditures of the magnitude appropriate for AFUDC treatment as well as other construction expenditures receiving CWIP treatment. The expenditures for AFUDC construction activity are projected to be placed in-service October 2013. Therefore, an entry in Line 1.b. "Clearing to Plant" must be made indicating the amount to be added to Line 2 "Plant-in Service/Depreciation Base" for October 2013. Once the entry to "Clearing to Plant" was made, it created a negative balance in Line 4 "CWIP – Non-Interest Bearing" for October in cell P22. In order for cell P22 to reflect the correct balance to account for the AFUDC treatment as well as the CWIP treatment for other project construction activity, the formula in cell P22 had to be changed to reflect just the $300,000 of ongoing CWIP construction activity. Therefore, the formula for October accurately reflects the $300,000 balance in CWIP at the same time the project earning AFUDC is projected to be placed in-service.

For December, the same accounting treatment applies in that additional project activity accruing AFUDC has been occurring

while other construction activity receiving CWIP treatment has been occurring. Both types of construction activity are projected to be placed in-service December 2013 and thus, the need for Line 4 "CWIP – Non-Interest Bearing" cell location R22 to reflect a zero balance.

The specific tracking of the AFUDC project expenditures during the time of construction has been identified in Line 1.c. "Other" with an explanation provided in Note G.

b. (i) The numbers in the calculation for cell P22 in worksheet "Form 42-4P, p9" represent the following expenditures:

$70,186	Expenditures for Sep-Dec 2011;
$571,098	Expenditures for Jan-Dec 2012;
$1,110,000	Expenditures for Jan-Oct 2013.

(ii) The above-referenced numbers were added to the calculation in October 2013 per projected in-service date. As previously stated above, these expenditures were earning AFUDC and therefore not included in CWIP.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Howard Bryant who deposed and said that he is Manager - Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Third Set of Interrogatories, (Nos. 13 - 15) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 4th day of October, 2012.

Howard T. Bryant

Sworn to and subscribed before me this 4th day of October, 2012.

Cynthia R. Kyle

Notary Public State of Florida
Cynthia R Kyle
My Commission EE052251
Expires 03/01/2015

My Commission expires _____

18

GULF's Response to Staff's 1st Set of Interrogatories (Nos. 1-2)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 120007-EI

Date Filed: April 12, 2012

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-2)

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. 1-2) on the following pages.

Respectfully submitted by electronic mail the 12th day of April, 2012,

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

1. Please provide updated information on Plant Daniel Units 1 and 2 Scrubber projects and SCRs projects. For each project please include the following information in your responses:
   a. Project starting date
   b. Planned in-service date
   c. Estimated total capital costs (Gulf's share)
   d. Estimated annual O&M costs (Gulf's share)
   e. Project number as shown in the ECRC filing and its associated Excel files of Schedules 42-8A, 42-8E, and 42-4P
   f. FPSC Commission order number in which ECRC cost recovery of the project was granted.

ANSWER:

a. Detailed engineering design for the Plant Daniel scrubber projects began during January of 2011. Foundation work is scheduled to begin during April of 2012.

Detailed engineering work for the Daniel SCRs is scheduled to begin during January of 2014 and construction is expected to start during October of 2014.

b. The Daniel scrubber projects are scheduled to be placed in-service during December of 2015. The Daniel Unit 1 and Unit 2 SCRs are currently projected to be placed in-service during the fall of 2018 and the fall of 2017, respectively.

c. Projected capital expenditures for the Daniel scrubber projects are approximately [redacted] (Gulf's ownership portion). Capital expenditures for the Daniel Unit 1 and Unit 2 SCRs are projected to be approximately [redacted] and [redacted], respectively (Gulf's ownership portion).

d. Annual O&M expenses for the Daniel scrubbers are projected to total approximately [redacted] (Gulf's ownership portion). The projected annual O&M costs for the SCRs are [redacted] for each unit (Gulf's ownership portion).

e. The Daniel Unit 1 and Unit 2 Scrubbers are assigned project number (PE) 1551. The Daniel Unit 1 SCR project is assigned project number (PE) 1548 and the Daniel Unit 2 SCR project is assigned project number (PE) 1550. Each of these projects will be included in the ECRC project titled "CAIR/CAMR/CAVR Compliance" which is page 26 of Schedules 8A, 8E, and 4P and included in the excel files as the tab labeled "c26" respectively.

f. The Plant Daniel scrubber project was approved in Docket No. 070007-EI, Order No. PSC-07-0721-S-EI.

The Plant Daniel Units 1 and 2 SCRs were approved in Docket No. 100007-EI, Order No. PSC-10-0683-FOF-EI.

2. Please complete the following table regarding Gulf's air emission controls.

Gulf Power Company's Air Emission Control Systems

Plant Name	Unit No.	Unit Type (ST/CT/CC)	Operation Mode (base/inter/peak)	Existing System (FGD/SCR)	System under construction	In-service Date	ECRC Project No.
Crist	4	ST	Base	FGD/SNCR ESP/INJ		FGD-12/2009 SNCR- 4/2006 ESP- 3/2008 INJ- 12/2005	FGD-1222 SNCR-1287 ESP- 1175 INJ- 1214
	5	ST	Base	FGD/SNCR ESP/INJ		FGD- 12/2009 SNCR- 4/2006 ESP- 3/2008 INJ- 12/2005	FGD-1222 SNCR-1287 ESP- 1191 INJ- 1214
	6	ST	Base	FGD/SNCR LNB/OFA	SCR, ESP	FGD-12/2009 SNCR-11/2005 LNB/OFA-11/2005 SCR- 4/2012 ESP- 6/2012	FGD-1222 SNCR- 1287 LNB/OFA-1287 SCR- 1279 ESP- 1038
	7	ST	Base	FGD/SCR ESP/LNB		FGD- 12/2009 SCR- 4/2005 ESP- 4/2004 LNB- 5/2004	FGD-1222 SCR- 1199 ESP- 1199 LNB- 1234
Smith	1	ST	Base	SNCR/ESP INJ		SNCR- 5/2009 ESP- 5/2007 INJ- 1999	SNCR-1468,1469 ESP- 1461 INJ-1413
	2	ST	Base	SNCR/OFA ESP/INJ		SNCR- 12/2008 ESP- 4/2005 INJ-1999	SNCR- 1468 ESP- 1462 INJ- 1413
	3	CC	Inter	DNL		2003	
	A	CT	Peak				
Daniel	1	ST	Base	Cold Precipitator LNB	FGD	Precipitator-1977 LNB- 5/2010 FGD- Fall 2015 SCR– 2018	 LNB- 1824 FGD-1551 SCR-1548
	2	ST	Base	Cold Precipitator LNB/OFA	FGD	Precipitator- 1981 LNB/OFA- 12/2008 FGD- Fall 2015 SCR- 2017	 LNB/OFA-1826 FGD-1551 SCR-1550
Scholz	1	ST	Base	ESPC		ESPC-11/2003	ESPC-1330
	2	ST	Base	ESPC, ESP		ESPC-11/2003 ESP-12/2007	ESPC-1330 ESP - 1305
Scherer	1	ST	Base	FGD/SCR/ Bag	Environmental costs for Gulf's ownership portion of Scherer Unit 3 are not included in Gulf's ECRC.		

Note:
ST = Fossil Steam, CT = Combustion Turbine, CC = Combined Cycle
Base = base load, inter = intermediate load, peak = peak load
FGD = Fuel gas desulfurization, SCR = Selective Catalytic Reduction,
SNCR = Selective Non-catalytic Reduction, DNL = Dry Low NOx Combustors,
OFA = Overfire Air; LNB= Low NOx Burners, ESPC= Electrostatic Precipitator Controls,
ESP= Electrostatic Precipitator upgrade, INJ= Sodium Injection

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 120007-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Secretary and Treasurer and Regulatory 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
Secretary and Treasurer and
Regulatory Manager

Sworn to and subscribed before me this 12th day of April, 2012.

Notary Public, State of Florida at Large

MONICA A WILLIAMS
MY COMMISSION # EE166803
EXPIRES February 06, 2016
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GULF's Response to Staff's 2nd Set of Interrogatories (Nos. 3-6)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No. 120007-EI
	Date Filed: May 29, 2012

GULF POWER COMPANY'S RESPONSES TO
STAFF'S SECOND SET OF INTERROGATORIES (NOS. 3-6)

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. 3-6) on the following pages.

Respectfully submitted by U.S. mail the 29th day of May, 2012,

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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Attorneys for Gulf Power Company

Please refer to witness O. Vick's testimony filed April 2, 2012, for questions 3 – 4.

3. Referring to lines 1 – 8 on page 4,
   (a) Please elaborate on the statement "... because of changes in the timing of portions of the Plant Crist Unit 6 SCR project being placed into service."
   (b) What were the initial times and the changed times for each portion of the project discussed on lines 3 – 5?
   (c) What were the dollar amounts of the capital variance associated with each portion indentified in response to question 3(b)?

ANSWER:

a. The items in 3(c) were originally budgeted to be placed in service in 2012; however, they were actually placed in service during July-December 2011.

b. See Response to 3(a)

c. The dollar amounts for the capital additions that cleared into service referenced in Gulf's Response to 3(a) are listed below.

Capital Component	**Capital Additions**
Common Work and Electrical Equipment	$ 370,000
Station Service Transformers	$1,140,000
Economizer Duct and Dry Ash	$1,110,000

4. Referring to lines 20 – 23 on page 6, when does Gulf expect the maintenance work to be completed?

ANSWER:

At the time of the Final True-Up, Gulf expected that the maintenance was delayed rather than cancelled. Since the 2011 Final True-up was filed on April 1, 2012, more detailed inspections were performed by the tank manufacturer and it has been decided that exterior surface work is not needed; therefore this project has been canceled for the present time.

Please refer to Gulf's Environmental Compliance Program Update filed April 2, 2012, for questions 5 – 6.

5. On page 15 the Company indicated that the Plant Crist Units 4 through 7 FGD scrubber became operational in December 2009. Please response to the following questions in this regard.

(a) How many tons of gypsum were produced annually by the FGD since it was placed in-service?
(b) How did Gulf dispose of the gypsum produced by the scrubber?
(c) What are the annual O&M costs associated with the disposal of the gypsum at the Plant Crist Units?
(d) Is there an on-site gypsum storage facility at Plant Crist?
(e) If the response to 5(d) is affirmative, what is the size (in acres) and capacity (in tons) of the facility?
(f) If the response to 5(d) is affirmative, when was the storage facility built? What were the capital costs associated with the construction? What are the annual O&M costs for operating the facility?
(g) If the response to 5.(d) is affirmative, in how many years will the facility reach its limit? What is the designed life of the facility?
(h) Does Gulf own an off-site landfill for gypsum disposal?
(i) If the response to 5.(h) is affirmative, what is the size (in acres) and capacity (in tons) of the facility, and how far is it from Plant Crist?
(j) If the response to 5.(h) is affirmative, in how many years will the facility reach its limit? What is the designed life of the facility?
(k) Does Gulf dispose of gypsum at a third-party landfill(s)?
(l) If the response to 5(k) is affirmative, what is the tipping fee ($/ton)?
(m) If the response to 5(k) is affirmative, how far away from the landfill is Plant Crist and what is the transportation cost ($/ton-mile)?
(n) Does Gulf market gypsum?
(o) If the response to 5(n) is affirmative, for each year that gypsum has been marketed, what percentage of the gypsum produced was sold? What were the proceeds from each year's sales? Were the proceeds returned to ratepayers through the ECRC? If no, please explain why not.
(p) If the response to 5.(n) is negative, please explain why not.

ANSWER:

a. There were [redacted] tons of gypsum produced in 2010 and [redacted] tons of gypsum produced in 2011 by the FGD since it was placed in service.

b. During 2010 and 2011 gypsum produced by the scrubber was beneficially reused or placed into a permitted pond. The table below shows the breakdown for 2010 and 2011.

Disposal Type	2010 (in tons)	2011
Beneficially Reused	[redacted]	[redacted]
Placed in Permitted Pond	[redacted]	[redacted]

c. The O&M costs associated with the disposal/handling of the gypsum at Plant Crist was approximately $388,000 in 2011.

d. Yes.

e. The size of the on-site gypsum storage facility at Plant Crist is 156 acres with a capacity of [redacted] tons.

f. The storage facility is to be constructed in phases. The completed phase for the current storage area was completed in 2009 and at a cost of [redacted]. The O&M costs for operating the facility associated with the disposal/handling of the gypsum at Plant Crist in 2011 were approximately $388,000.

g. Under current operating parameters; estimating approximately [redacted] of gypsum generated each year and 100% being stored on-site, the life of the entire storage facility would be approximately [redacted]. Based on the assumption of [redacted] /year gypsum generated, the designated life of the facility would be [redacted].

h. No.

i. N/A

j. N/A

k. No.

l. N/A

m. N/A

n. Yes.

o. In 2010, 64.5% of the gypsum produced was beneficially reused, resulting in sales of approximately [redacted]. In 2011, 61.8% of the gypsum produced was beneficially reused, resulting in sales of approximately [redacted]. All proceeds received from the sale of gypsum are treated as a reduction to O&M expense recovered through the Environmental Cost Recovery Clause.

p. N/A

6. On page 17 the Company indicated that the Plant Daniel Units 1 & 2 scrubber projects are currently scheduled for completion in fall of 2015. Please respond to the following questions in this regard.

(a) How many tons of gypsum will be produced annually by the FGD after it is placed in-service?
(b) How does Gulf plan to dispose of the gypsum produced by the scrubber?
(c) What are the estimated annual O&M costs associated with the gypsum disposal?

ANSWER:

a. The amount of gypsum produced will be dictated solely by the % sulfur in the fuel supply and the amount of fuel consumed. Based on the proposed fuel budget, an estimated [redacted] of gypsum will be produced annually by the FGD after it is placed in service.

b. Mississippi Power Company, as the operator of Plant Daniel, plans to market the gypsum [redacted]. Gypsum not marketed will be stored or disposed of in the subtitle D storage facility on site.

c. The total estimated annual O&M costs for disposal of gypsum is [redacted] per year (in 2014 dollars). Gulf's share of the O&M costs would be 50% of this estimate.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 120007-EI

Before me the undersigned authority, personally appeared Terry A. Davis, Assistant Secretary and Assistant Treasurer 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.

Terry A. Davis
Assistant Secretary and Assistant Treasurer

Sworn to and subscribed before me this 29th day of May, 2012.

Notary Public, State of Florida at Large

MONICA A WILLIAMS
MY COMMISSION # EE166803
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(407) 398-0153 FloridaNotaryService.com

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GULF's Response to Staff's 3rd Set of Interrogatories (Nos. 7-9)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 120007-EI

Date Filed: June 29, 2012

GULF POWER COMPANY'S RESPONSES TO
STAFF'S THIRD SET OF INTERROGATORIES (NOS. 7-9)

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. 7-9) on the following pages.

Respectfully submitted by electronic mail the 29th day of June, 2012,

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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Attorneys for Gulf Power Company

Please refer to the schedules, and the corresponding Excel file "Gulf Power_120007-EI_Final True Up field 4-2-12 (2).xlsx," of the ECRC Final True-up for the period January 2011 through December 2011, that Gulf filed on April 2, 2012, for the following questions.

7. This question pertains to project "Air Quality Assurance Testing" reported on page 1 of Schedule 8A and its corresponding Excel worksheet "c1" and "DepExp." The project consists of two sub-projects: PE1006, which has been fully amortized, and PE 1244, which is on 7 year amortization schedule. Referring to columns F (December 2010) and G (January 2011) on row 47 (PE 1244 CEMS Analyzers for Rata Test Trailers) contained in Excel worksheet "DepExp," please explain in detail why the monthly amortization amount was changed from $2,622.55 in December 2010 to $4,176.33 in January 2011.

ANSWER:

In December 2010 $130,518.05 was added to plant in service. This addition resulted in an increase to monthly amortization of $1,553.78. See below for calculation.

Plant in service x 7 year rate / 12 months = monthly amortization
$130,518.05 x 14.2857% / 12 = $1,553.78

8. Please refer to project "SO2 Allowances" reported on page 31 of 31 of Schedule 8A and its corresponding Excel worksheets "Allow" and "Emissions(2)" for the following questions.

   a. Please explain what row 23 DEFERRED GAIN RECOGNIZED ON SO2 EMISSIONS on worksheet Emissions(2) represents.
   b. Please explain what row 28 SO2 Allowance Auction Proceeds & Fees of worksheet "Emissions(2)" represents.
   c. Please explain how an emission allowance auction [pertains to rows 28, 29 and 30 in worksheet "Emissions(2)"] is carried out.
   d. Please explain how, and usually from whom, an allowance purchase [row 32 in worksheet "Emissions(2)"] occurs.

ANSWER:

a. "Deferred Gain Recognized on SO2 Emissions" represents the amortization of the deferred gain/proceeds from previous auctions. Each year, Gulf receives auction proceeds for SO2 allowances. These auction proceeds are posted to a Regulatory Liability Deferred Gain account based on the vintage year of the allowances. The gain is amortized over a 12 month period when that vintage year applies.

b. "SO2 Allowance Auction Proceeds & Fees" represents the auction proceeds Gulf receives from the SO2 auction each year. These proceeds are then deferred based on vintage year and amortized in that vintage year.

c. Title IV of the Clean Air Act Amendments (Acid Rain Program) mandates that the Environmental Protection Agency (EPA) hold or sponsor yearly auctions of allowances for a small portion of the total allowances allocated each year. The auctions help ensure that new units have a public source of allowances beyond those allocated initially to existing units. To supply the auctions with allowances, the EPA sets aside an auction allowance Reserve of approximately 2.8 percent of the total annual allowances allocated to all units. During Phase I, when the allocated allowances totaled 5.7 million allowances annually, 150,000 allowances were withheld every year for auctions. During Phase II, when allowance allocations totaled 8.95 million allowances annually, 250,000 allowances were withheld annually for auctions.

The auctions began in 1993 and are held annually, usually on the last Monday of March. Auctions are divided into two segments: (1) a spot allowance auction, in which allowances are sold that can be used in that same year for compliance purposes, and (2) an advance auction for the sale of allowances that will become usable for compliance 7 years after the transaction date, although they can be traded earlier. The EPA returns proceeds and unsold allowances from the auctioning of reserve allowances on a pro rata basis to those units from which EPA originally withheld allowances to create the auction reserve. Proceeds from the sale of offered allowances are returned to allowance holders that contributed the allowances to the auctions. The EPA likewise returns payment from unsuccessful bids and allowances from unsuccessful offers.

The proceeds in row 28 in the worksheet "Emissions(2)", represent Gulf's ownership of allowance assets received from the EPA for the 2011 annual SO2 Acid Rain auction. There is not currently an auction for annual NOx or Seasonal NOx outlined in row 29 and 30.

d. Each operating company develops an annual compliance strategy at the beginning of the year to procure emission allowances if a need is determined. If an allowance need is determined, the operating company will agree to a procurement strategy and give its approval to purchase allowances. Emission allowances are purchased over the counter (OTC) through a broker ensuring the operating company receives the best price and is matched with a credit worthy counterparty.

The expense in row 32 in the worksheet "Emissions(2)", represent the purchases of NOx allowances required for Gulf to maintain compliance to the 2011 Seasonal Ozone Program under the Clean Air Interstate Rule (CAIR).

9. Referring to Line 9 Adjustments in Schedule 2A, please provide a detailed explanation of the cause and nature of the $867 adjustment reported in column "September."

ANSWER:

The proceeds for Plant Daniel from 2009 for $13,386.93 were not booked correctly. Because of this, the $13,386.93 was never placed into the Regulatory Liability Deferred Gain account to be amortized each month and credited back to the customer through the environmental clause. An entry was prepared in September 2011 to move the 2011 portion of these gains ($12,223.21) to the Gain from Disposition of Allowances account to provide a credit to the customers in the environmental clause for September. The 2016 portion ($1,163.72) was moved to the Regulatory Liability Deferred Gain account for vintage year 2016. The adjustment for $867 is the interest impact to the environmental clause for these proceeds not being booked correctly in 2009.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 120007-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Secretary and Treasurer and Regulatory 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
Secretary and Treasurer and
Regulatory Manager

Sworn to and subscribed before me this 29th day of June, 2012.

Notary Public, State of Florida at Large

MONICA A WILLIAMS
MY COMMISSION # EE166803
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21

GULF's Response to Staff's 4th Set of Interrogatories (No. 10)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 120007-EI

Date Filed: September 13, 2012

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FOURTH SET OF INTERROGATORIES (NO. 10)

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 (No. 10) on the following pages.

Respectfully submitted by electronic mail the 13th day of September, 2012,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
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STEVEN R. GRIFFIN
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Attorneys for Gulf Power Company

10. Referring to page 7, lines 1 – 11, of witness J. Vick's testimony filed on August 1, 2012.

a. Please identify the percentage of the increased tonnage of gypsum sales at Plant Crist compared with 2011 data.
b. Please identify the percentage of the increased dollar amounts resulting from the increased gypsum sales compared with 2011 data.
c. Please identify the factors that resulted in the increase in the gypsum sales. Please explain your response.

ANSWER:

a. Gulf expects to sell approximately 13,000 more tons of gypsum in 2012 than it sold in 2011 which represents a 17% increase.

b. Gulf expects the dollar amount of gypsum sales (net of expenses) to increase approximately $320,000 in 2012 as compared to 2011 which represents a 164% increase.

c. The increase in gypsum sales is primarily due to a greater demand for gypsum from the end users.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 120007-EI

Before me the undersigned authority, personally appeared Terry A. Davis, Assistant Secretary and Assistant Treasurer, 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.

Terry A. Davis
Assistant Secretary and Assistant Treasurer

Sworn to and subscribed before me this 13th day of September, 2012.

Notary Public, State of Florida at Large

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22

GULF's Response to Staff's 5th Set of Interrogatories (Nos. 11-13)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 120007-EI

Date Filed: October 9, 2012

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 11-13)

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. 11-13) on the following pages.

Respectfully submitted by electronic mail the 9th day of October, 2012,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
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Attorneys for Gulf Power Company

11. Please refer to page 26 of Schedule 8A filed April 1, 2012, and page 26 of Schedule 8E filed July 31, 2012. For CAIR/CAMR/CAVR Compliance:

a. Please explain why the 2012 beginning balance of Line 2 "Plant-in-Service/Depreciation Base" [which is $625,142,855] on page 26 of Schedule 8E is not tied to the 2011 ending balance for the same Line [which is $640,435,374] on page 26 of Schedule 8A.

b. Please explain why the 2012 beginning balance of Line 3 "Less Accumulated Depreciation" [which is negative $53,266,652] on page 26 of Schedule 8E is not tied to the 2011 ending balance for the same Line [which is negative $54,292,094] on page 26 of Schedule 8A.

ANSWER:

This difference reflects the removal of the Crist Unit 6 and 7 Turbine Upgrade projects from the Environmental Cost Recovery Clause on 12/31/11 pursuant to the stipulation approved in Commission Order No. PSC-11-0553-FOF-EI.

The removal of the Plant Crist Units 6 and 7 turbine upgrades from ECRC required Plant-in-Service to be reduced by $15,292,517.43 and the associated accumulated depreciation to be adjusted by $1,025,442.29. See table below that ties the 2011 ending balances to the 2012 beginning balances for Plant-in-Service and Accumulated Depreciation based on the removal of the Plant Crist Units 6 and 7 turbine upgrades from ECRC.

	Ending Balance 2011	Removal of Turbine Upgrades	Beginning Balance 2012
Plant-in-Service	$640,435,374	$ (15,292,519)	$ 625,142,855
Accumulated Depreciation	$ 54,292,094	$ (1,025,442)	$ 53,266,652

12. Please refer to page 1 of Schedule 8E filed July 31, 2012, and page 1 of Schedule 4P filed August 28, 2012. For the same project Air Quality Assurance Testing, please explain why the 2013 beginning balance of Line 3 "Less Accumulated Depreciation" [which is $0] on page 1 of Schedule 4P is not tied to the 2012 ending balance for the same Line [which is negative $267,855] on page 1 of Schedule 8E.

ANSWER:

The beginning balance for PE1244 (CEMS Analyzers for Rata Test Trailer) was inadvertently misstated on schedule 4P page 1 of 31 as $0 rather than $(267,855). This error affects schedules 1P, 3P, 4P page 1 of 31, and 7P. The revised schedules reflecting the correction of this inadvertent error were filed on October 5, 2012.

13. Referring to Line 6 "Retail Demand Recovery Factor" on Schedules 5E and 7E filed July 31, 2012, please explain why Gulf used the Commission Order PSC-11-0553-FOF-EI, page 4, prescribed factor (which is 0.9644582) for the period January 2012 through March 2012 only, but used a different factor (which is 0.9657346) for the period April 2012 through December 2012.

ANSWER:

For January through March 2012, Gulf used the retail demand allocator approved in Commission Order PSC-11-0553-FOF-EI. Beginning April 2012, Gulf used the demand allocation factor derived from the cost-of-service study filed and approved in its most recent base rate case, Docket No. 110138-EI, Order No. PSC-12-0179-FOF-EI issued April 3, 2012.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 120007-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Secretary and Treasurer, 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
Secretary and Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 9th day of October, 2012.

Notary Public, State of Florida at Large

MONICA A WILLIAMS
MY COMMISSION # EE166803
EXPIRES February 06, 2016
(407) 398-0153 FloridaNotaryService.com

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Gulf Power Company
Environmental Compliance
Program Update

GULF POWER COMPANY
ENVIRONMENTAL COMPLIANCE PROGRAM UPDATE

For

Clean Air Interstate Rule
Cross State Air Pollution Rule
National Ambient Air Quality Standards
Mercury and Air Toxics Standards
Clean Air Visibility Rule

GULF POWER
A SOUTHERN COMPANY

April 2, 2012

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1.0 EXECUTIVE SUMMARY

Since the Clean Air Act Amendments (CAAA) were passed by Congress in 1990, Gulf Power Company (Gulf Power or Gulf) has reviewed and updated its environmental compliance planning as needed on an on-going basis. The goal of this process is to identify reasonable, cost-effective compliance strategies that will minimize the impact on Gulf Power's customers while achieving environmental objectives and assuring compliance with all environmental requirements.

On June 22, 2007, the Office of Public Counsel (OPC), the Florida Industrial Power Users' Group (FIPUG) and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's compliance plan. That stipulation identified 10 specific components, Phase I, of Gulf's program as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the program. On August 14, 2007, the Florida Public Service Commission (Commission or FPSC) voted to approve the stipulation with the proviso that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its program into which the Company is moving.

This document is the fifth update of Gulf's original environmental compliance program[1] approved by the Commission in Order No. PSC-07-0721-S-EI. That program: (a) addressed the requirements of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR); (b) reviewed the decision process for assuring compliance at Gulf Power; and (c) provided cost estimates for incorporating these requirements at Gulf Power. The document reviewed the specific issues, timing, alternatives, process, and costs necessary for compliance with the new federal rules and the corresponding implementation programs developed by the Florida Department of Environmental Protection (FDEP) and the Mississippi Department of Environmental Quality (MDEQ).

Since the Commission's approval of Gulf's compliance program in 2007, there have been a number of regulatory and legislative developments. Gulf has addressed in several of its intervening filings, as well as in the annual updates, regulatory updates and changes to schedules of approved projects. There have been several significant court decisions that have had and will have further impact on Gulf's compliance program.

On August 8, 2011, the Environmental Protection Agency (EPA) adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NOx that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending resolution of litigation challenging the rule. The states of Florida and Mississippi had already completed plans to implement CAIR, and emissions reductions were being accomplished by the installation and operation of emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances. Gulf is

1- The title of Gulf's compliance environmental program has been revised since the original filing in March of 2007. CSAPR, NAAQS, and MATS were added to the title when the rules were adopted. Likewise, CAMR was removed from the title when the CAMR rule was vacated.

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continuing its assessment of the recent CSAPR revisions. If CSAPR remains in its current form and Florida and Mississippi are no longer included in the annual SO_2 and NOx programs, it will have the effect of requiring Florida and Mississippi to revise their regional haze state implementation plans to include Electric Generating Unit (EGU) Best Available Retrofit Technology (BART) determinations.

In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued an opinion vacating the EPA's CAMR. In a separate proceeding in the U.S. District Court for the District of Columbia, the Court, under a consent decree, required the EPA to issue a proposed EGU Maximum Achievable Control Technology (MACT) rule by March 16, 2011, and a final rule by November 16, 2011. The MACT rule, renamed the Mercury and Air Toxics Standards (MATS), was published in the federal register on February 16, 2012. The MATS rule imposes stringent emissions limits for mercury, acid gases and other (non-mercury) metals on coal and oil-fired electric utility generating units. Compliance for existing sources is required by April 16, 2015, three years after the effective date of the rule. Gulf is currently evaluating potential MATS compliance options.

Compliance with the MATS rule is likely to require substantial capital expenditures and compliance costs at the Company's facilities. These costs may arise from unit retirements, installation of additional emission controls, changing fuel sources for certain existing units, the addition of new generating resources, and/or upgrades to the transmission system. The MATS rule also requires installation of additional continuous emission monitors and/or additional emissions testing.

This document addresses Gulf's ongoing compliance projects and the reasons Gulf plans to continue these projects. Florida and Mississippi's state implementation plans for CAIR must be met. Decisions regarding Gulf's CAIR compliance strategy were made jointly with the CAVR and CAMR compliance plans due to co-benefits of proposed controls. In response to finalization of the MATS rule and revisions to the CSAPR, these plans are being evaluated for compliance with the new standards. Once the Company determines the most cost-effective compliance options, Gulf will submit revisions to the environmental compliance program for the Commission's review. Gulf Power's compliance program will be impacted by factors such as: final requirements of new or revised environmental regulations; the cost and availability of emissions allowances; performance of emission control equipment; and changes to the Company's fuel mix. Based on these factors, future environmental compliance costs will continue to be incurred, and projections will be revised. The timing of the requirements and costs incurred will be a function of the compliance options selected, new generating resources, fuel sources and prices, fuel sulfur content, transmission upgrades, energy demand, and other variables.

A capital and operations and maintenance (O&M) cost summary for Gulf's compliance program for CAIR, CAMR, and CAVR is provided in Table 1.0-1. Detailed capital and O&M costs are provided in Section 3 of this document. In response to finalization of the MATS rule and revisions to the CSAPR, these plans are being evaluated for compliance with the new standards.

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As noted in the Commission's approval of Gulf's original environmental compliance program, the program would likely evolve over time. At present, only Phase I projects and one Phase II project, the Daniel Unit 1 and Unit 2 Selective Catalytic Reduction (SCR) project, have been approved by the Commission. The remaining Phase II components of Gulf's compliance program, the Plant Smith Units 1 and 2 scrubber and the Plant Smith baghouse project, remain in the planning phase and the schedule and decisions about these projects remain very flexible. The Plant Smith scrubber and baghouse projects are included in Gulf's compliance program for future consideration.

Gulf Power has remained in compliance with all requirements of the CAAA and has addressed local concerns regarding potential ozone non-attainment in Pensacola and along the Gulf Coast. Implementation of the program described in this document will help assure continued compliance; however, the new one-hour SO_2 standards and the anticipated new ozone standard may still result in the Pensacola area or other areas of Florida and Mississippi being designated as non-attainment. The EPA finalized the new one-hour SO_2 standard during 2010 with state non-attainment designations due in mid-2012. The EPA is expected to finalize a new eight-hour ozone standard in the 2014 timeframe, with state implementation plans for any non-attainment areas due in 2017.

In addition to the air rules mentioned above that are aimed at reductions of NOx, SO_2, mercury, acid gases and other (non-mercury) metals, there are multiple state, federal and international initiatives regarding greenhouse gases (GHG), particularly carbon dioxide (CO_2), pending. If adopted, these rules could further impact Gulf's compliance program. All of this uncertainty reinforces the need for a flexible, robust compliance plan. Accordingly, as Gulf finalizes its strategy for complying with the new MATS regulations and revisions to the CSAPR, as decision dates for equipment purchases approach, and as regulatory and economic drivers become better defined, the analysis will be updated as needed to enable the selection of the most reasonable and cost-effective compliance alternatives while maintaining future flexibility in the plan.

Table 1.0-1
Projected 2012-2019 Compliance Program
Capital and O&M Costs by Plant

Plant	Phase I Capital Expenditures ($ in millions)	Phase II Capital Expenditures ($ in millions)	Phase I O&M Expenses ($ in millions)	Phase II O&M Expenses ($ in millions)
Crist	57	0	148	0
Daniel*	350	243	32	17
Smith	0.2	242	14	8
Scholz	0	0	0	0
TOTAL	407	485	194	25

*Costs for Gulf Power's ownership portion of Plant Daniel in Mississippi.
Note: Phase II projects include the Smith Scrubber, Smith Baghouse, and Daniel SCRs. Allowance cost projections are not included in Table 1.0-1.

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2.0 REGULATORY AND LEGISLATIVE UPDATE

This section provides a regulatory and legislative update and review of the CAIR and its stayed replacement rule the Cross State Air Pollution Rule (CSAPR), National Ambient Air Quality Standards (NAAQS), the CAVR, as well as the CAMR and its replacement rule the Mercury and Air Toxics Standards (MATS).

2.1 CLEAN AIR INTERSTATE RULE / CROSS STATE AIR POLLUTION RULE

In March 2005, the EPA published the final CAIR, a rule that addresses transport of SO_2 and NOx emissions that contribute to non-attainment of the ozone and fine particulate matter NAAQS in the eastern United States. This cap and trade rule addresses power plant SO_2 and NOx emissions that were found to contribute to non-attainment of the 8-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including Florida and Mississippi, are subject to the requirements of the rule. The rule calls for additional reductions of NOx and SO_2 to be achieved in two phases, 2009/2010 and 2015, as shown in Table 2.1-1.

Table 2.1-1

CAIR Emission Reduction Requirements

Emissions	Phase I reduction from acid rain allocations or current emissions	Phase II reduction from current allocations or current emissions
SO_2	50% (2010)	66% (2015)
NOx	50% (2009)	65% (2015)

In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating certain aspects of CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the CSAPR to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued an order granting motions to stay the CSAPR pending resolution of litigation in which numerous petitioners challenged the rule. The order states that the EPA "is expected to continue administering the Clean Air Interstate Rule" while litigation is ongoing. The states of Florida and Mississippi had already completed plans to implement CAIR, and emissions reductions were being accomplished by the installation and operation of emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances.

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Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations. On February 7, 2012, the EPA released final technical revisions to the CSAPR and at the same time issued a direct final rule providing additional increases to certain state emission budgets, including Florida and Mississippi. Decisions regarding Gulf's CAIR compliance strategy were made jointly with the CAVR and CAMR compliance plans due to co-benefits of proposed controls. In response to finalization of the MATS rule and revisions to the CSAPR, these plans are being evaluated for compliance with the new standards and will be updated as needed.

2.2 NATIONAL AMBIENT AIR QUALITY STANDARDS

Final revisions to the National Ambient Air Quality Standard for SO_2, including establishment of a new one-hour standard, became effective during August 2010. Since the EPA intends to rely on monitoring data and computer modeling for implementation of the SO_2 standard, the identification of potential non-attainment areas remains uncertain and could ultimately include areas within the Company's service area. The EPA is expected to designate areas as attainment and non-attainment under the new standard in mid-2012. Demonstration of compliance with the one-hour SO_2 NAAQS via modeling could be required by 2014 for all areas, including both non-attainment and unclassifiable/attainment areas. Implementation of the revised SO_2 standard could require additional reductions of SO_2 emissions and increased compliance and operation costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour ozone standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard during January 2012. None of the areas within the Company's service area were designated as non-attainment. While this standard is not focused on the electric utility sector, the new NO_2 standard could result in additional compliance and operational costs for units that require new source permitting.

2.3 CLEAN AIR VISIBILITY RULE

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018 and for each 10-year planning period thereafter. For power plants, the CAVR allows states to determine that the CAIR satisfies BART requirements for SO_2 and NOx.

The states of Mississippi and Florida have submitted regional haze state implementation plans (SIPs) to EPA. These plans indicated that no additional controls beyond CAIR were anticipated to be necessary at any of the Company's facilities. However, the FDEP is scheduled to update their SIP by mid-April 2012. EPA's deadline for submitting comments

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on their limited approval of two revisions to Mississippi's SIP revisions were due on or before March 29, 2012. Until these issues are resolved, it remains uncertain whether additional controls may be required for CAVR and BART compliance.

2.4 CLEAN AIR MERCURY RULE / MERCURY AND AIR TOXICS STANDARDS

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap and trade program for the reduction of mercury emissions from coal-fired power plants. The rule set caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provided for an emission allowance trading market. The final CAMR was challenged in the D.C. Circuit and in February 2008, the court issued an opinion vacating the CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements.

In a separate proceeding in the U.S. District Court for the District of Columbia, the Court, under a consent decree, required the EPA to issue a proposed MACT rule by March 16, 2011, and a final rule by November 16, 2011. On February 16, 2012, the EPA published the final Mercury Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and other (non-mercury) metals on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule. A one-year extension may be granted in certain cases based on replacement generation, transmission, and control technology needs. Sources needing a fifth year to comply, may seek an Administrative Order under Section 113(a) of the Clean Air Act. According to the EPA, an Administrative Order would be limited to units that are required to run for reliability purposes.

Gulf Power is currently evaluating potential MATS compliance options. Compliance with this rule is likely to require substantial capital expenditures and compliance costs at the Company's facilities. These costs may arise from unit retirements, installation of additional emission controls, changing fuel sources for certain existing units, the addition of new generating resources, and/or upgrades to the transmission system. The MATS rule also requires installation of additional continuous emission monitors and/or additional emissions testing.

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3.0 GULF'S COMPLIANCE PROGRAM

3.1 GULF POWER'S ELECTRIC GENERATING SYSTEM

Gulf Power owns and operates three fossil-fueled generating facilities in Northwest Florida (Plants Crist, Smith and Scholz). Gulf also owns a 50 percent undivided ownership interest in Unit 1 and Unit 2 at Mississippi Power Company's Plant Daniel. This fleet of generating units consists of ten fossil steam units, one combined cycle (CC) unit, and one combustion turbine (CT). The nameplate generating capacity of Gulf's generating fleet affected by CAIR/CSAPR, MATS, and/or CAVR is 2,783 megawatts (MW).

A summary of the compliance program capital projects and associated expenditures through 2019 is provided in Table 3.1-1. The projected plant O&M expenses associated with the capital projects are included in Table 3.1-2. The cost information is provided by plant and by project.

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Table 3.1-1
Compliance Program Capital Expenditures
$ in Thousands

	Prior Years**	2012	2013	2014	2015	2016	2017	2018	2019	Total
By Plant										
Plant Crist										
Mercury Monitoring		105								
Unit 6 SCR	147,790	51,094								
Units 4-7 Scrubber	633,762									
Plant Scholz										
Mercury Monitoring	644									
Plant Smith										
Unit 2 Baghouse*										
Unit 1 SNCR	8,363									
Unit 2 SNCR	2,905									
Mercury Monitoring	1,433									
Units 1-2 Scrubber *										
CAIR Parametric Monitor	230									
Plant Daniel										
Mercury Monitoring										
Unit 1 SCR										
Unit 2 SCR										
Units 1 & 2 Scrubber	23,737									
Unit 1 Low NOx Burners	3,187									
Unit 2 Low NOx Burners	3,586									
By Project										
Mercury Monitoring	2,077	105								
SCRs	147,790	51,094								
Scrubbers	657,499									
SNCRs	11,268									
Baghouse										
CAIR Parametric Monitor	230									
Low Nox Burners	6,773									
Annual Total	825,837									

* Phase II projects that have not been approved for ECRC recovery

**2006-2011 expenditures

Expenditures presented for Plant Daniel represent Gulf's ownership portion.

Allowance cost projections are not included in Table 3.1-1

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Table 3.1-2
Compliance Program Plant O&M Expenses
$ in Thousands

	2012	2013	2014	2015	2016	2017	2018	2019	Total
By Plant									
Plant Crist									
Mercury Monitoring									
Unit 6 SCR									
Units 4-7 Scrubber									
Plant Scholz									
Mercury Monitoring									
Plant Smith									
Unit 2 Baghouse*									
Unit 1 SNCR									
Mercury Monitoring									
Units 1-2 Scrubber*									
CAIR Parametric Monitor									
Plant Daniel									
Mercury Monitoring									
Unit 1 SCR									
Unit 2 SCR									
Units 1&2 Scrubber									
Unit 1 Low NOx Burners									
Unit 2 Low NOx Burners									
By Project									
Mercury Monitoring									
SCRs									
Scrubbers									
SNCRs									
Baghouse									
CAIR Parametric Monitor									
Low NOx Burners									
Annual Total									

* Phase II projects that have not been approved for ECRC recovery

Expenses presented for Plant Daniel represent Gulf's ownership portion.

Allowance cost projections are not included in Table 3.1-2

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3.2 COMPLIANCE OPTIONS

As part of Gulf's environmental compliance planning evaluation Gulf considers four major options for environmental compliance:

- Dependence on allowance purchases
- Fuel switching
- Retrofit of environmental emission controls to existing generating units
- Retirement of existing generating units and replacement with new or purchased generation

Combinations of these options are also considered.

3.2.1 Allowance Purchase Option

Allowance cap and trade programs are applicable to the Acid Rain, CAIR, and CSAPR programs. These programs consist of markets for annual SO_2 and NOx allowances and seasonal NOx allowances for ozone compliance. Cap and trade programs use a market-based approach to reduce emissions. The program sets a cap, or limit, for each pollutant such as SO_2 and NOx, which is then divided into emission allowances that are allocated to each affected source. Sources are allowed to determine the most reasonable, cost-effective way to comply. Facilities may install environmental emission controls, use fuel switching, replace the generating units, rely on the emission allowance market, or use some combination of these options.

3.2.2 Fuel Switching Option

Fuel switching refers to instances where an electric generating unit's primary fuel is changed to reduce emissions. For certain facilities, NOx emissions can be reduced by burning high-moisture, low-Btu sub-bituminous coals, while mercury emissions can be reduced by utilizing coal lower in mercury content. Co-firing with natural gas or switching to a natural gas fuel supply may be used as an option to lower NOx, SO_2, and mercury emissions for certain units. In Gulf's case, fuel switching to lower sulfur coal was shown under the Acid Rain Program to be a cost-effective means for reducing emissions of SO_2.

3.2.3 Retrofit Options

Retrofit options refer to additional environmental emission controls that can be installed on existing generating units. As discussed in Section 2, affected coal-fired electric generating units would be required to comply with SO_2, NOx, mercury, acid gas, and other (non-mercury) metal limits under CAIR/CSAPR, CAVR, and MATS if the units are to continue to operate. These reductions may be met by installing additional emission controls on existing

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units. Currently, the proven control technology of choice for SO_2 reduction is wet scrubbing. For NOx removal, there are a number of proven emission controls available such as Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), and Low NOx Burners (LNBs). Mercury reductions can be achieved as co-benefits from the installation of scrubber and SCR systems for the control of SO_2 and NO_x emissions, respectively. Other emission control equipment and options for MATS compliance are still being evaluated. For MATS compliance, units with a scrubber and a SCR may require additional controls such as a baghouse and/or sorbent injection. Units without a scrubber and a SCR may require additional controls such as a scrubber, baghouse, electrostatic precipitator improvement, and/or sorbent injection.

3.2.4 Retirement and Replacement Option

A retirement and replacement evaluation is used to compare retrofit compliance options to premature retirement and replacement of specific generating units in order to determine the most reasonable, cost-effective compliance option. The retirement option is typically more applicable to smaller, older, less efficient coal plants that cannot financially support the addition of environmental controls. The evaluation methodology and the 2012 evaluation results are discussed in Section 3.3.4.

3.3 GULF'S EVALUATION OF COMPLIANCE OPTIONS

3.3.1 Evaluation of Allowance Purchase Option

Allowance cap and trade programs are applicable to the Acid Rain, CAIR, and CSAPR programs. These programs consist of markets for annual SO_2 and NOx allowances and seasonal NOx allowances for ozone compliance. The SO_2 and seasonal NOx allowance markets have proven to be fundamentally driven by supply and demand. However, over time, many speculative investors have begun entering the allowance markets, particularly the SO_2 market, introducing considerable volatility and uncertainty concerning the price and availability of allowances.

With the high price volatility, the future price and availability of allowances could not be treated as predictable; therefore, depending solely on the market for SO_2 compliance presented a large risk for Gulf Power's customers when developing Gulf's original CAIR, CAMR, CAVR Compliance Plan. However, the market did provide realistic opportunities for reducing costs through limited purchases of allowances in conjunction with retrofitting several generating units with additional emission controls.

The retrofit installations set forth in Gulf's compliance program significantly reduced emissions; however, they did not result in Gulf achieving CAIR compliance levels without the purchase of some emission allowances. Thus, Gulf's environmental compliance program required the purchase of allowances during the 2007-2011 timeframe. Gulf is not projecting the need to purchase additional allowances during 2012 for CAIR compliance. Gulf plans to

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utilize its existing allowance bank until the CSAPR emissions trading limitations are promulgated.

Under the currently stayed CSAPR, it appears that the emission allowances previously issued under CAIR and/or the Acid Rain Program cannot be used to comply with the CSAPR requirements. Given the pending legal challenge to the CSAPR and the recent increases to certain states' CSAPR emissions budgets, Gulf is unable to predict future CSAPR allowance costs at this time. Gulf may need to begin incurring CSAPR allowance costs as early as 2012 to meet the CSAPR requirements once promulgated.

3.3.2 Evaluation of Fuel Switching Option

Fuel switching was shown under the Acid Rain Program to be cost effective for reducing emissions of SO_2 at some coal fired facilities. For certain facilities, NOx emissions can be reduced by burning high-moisture, low-Btu sub-bituminous coals, and some coals are lower in mercury content than others. However, for the magnitude of emission reductions required by CAIR/CSAPR, MATS, and CAVR, switching coal supplies alone was no longer a viable compliance option. Co-firing with natural gas or switching to a natural gas fuel supply may provide opportunities for certain coal-fired units to lower emissions of NOx, SO_2, and mercury.

3.3.3 Evaluation of Retrofit Options

Having determined that neither an all allowance compliance program nor an all fuel switching compliance program would be feasible or desirable, Gulf Power was left with the primary options of either retrofitting units or retiring and replacing units (and, if necessary, supplementing those options with allowance purchases or fuel switching). However, before making a comparison of retrofit and replacement options, Gulf Power first had to choose among competing retrofit options. Selections of the best retrofit options for CAIR, CAMR, and CAVR were discussed in Gulf's original environmental compliance program and have not changed, and therefore are not repeated here.

3.3.4 Evaluation of Retrofit versus Replacement Options

The selection between retrofit and replacement options is based upon a financial assessment of which option ultimately is expected to be the most reasonable, cost effective alternative for Gulf's customers. The analysis examines the relative cost of dispatching the System (a) with the retrofit technology in place and (b) with having retired the unit without making the retrofit and instead, replacing it with new capacity. The 2012 replacement analysis included Plant Daniel Units 1 and 2. The Plant Smith and Plant Crist economic analysis was not updated in 2012 because Gulf has not made any changes to the plants' compliance strategies, other than delaying completion of the Plant Smith mercury monitor installation and moving the Plant Scholz mercury monitor to Plant Crist.

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The Plant Daniel Units 1 and 2 analysis was performed using a detailed site specific methodology. The economic analysis focused on a comparison of Gulf's 50% ownership costs associated with continued operation with retrofit controls installed to replacement with a combined cycle unit. The economic analysis included hourly production cost modeling and cost implications to the transmission system. Changes in production cost, capital, and other fixed costs were captured in the comparison analysis to help determine the most economical option.

Methodology

The economic analysis focused on a comparison of Gulf's 50% ownership costs associated with continued operation with retrofit controls to replacement with a combined cycle unit at Plant Crist. This evaluation included refined commitment and energy value modeling and cost implications to the transmission system. Changes in energy value, capital, and other fixed costs were captured in the comparison analysis to help determine the most economical option. Replacement energy costs were estimated using the Southern Electric System marginal replacement costs for both the continued coal operation and the replacement alternative. Marginal replacement costs were generated with the Pro-Sym® model. The marginal replacement costs were then used in the Southern Company GenVal model to dispatch both the coal units and the combined cycle unit. The energy benefits (marginal replacement costs minus variable operating costs) were compared to determine the commitment and energy value to the Southern Electric System for both generating options. Fixed costs associated with the continued operation of the existing generating units were based on projections of annual O&M costs and the Net Present Value (NPV) of the revenue requirements associated with incremental capital investment necessary to keep the unit operational over the evaluation period. Replacement, installation capital, fixed O&M, and continue-to-operate capital are site specific costs. The replacement costs are pro-rated to an equal capacity basis with the studied unit. The NPV of the difference between the pro-rated replacement cost and unit operational cost is calculated to determine the overall net contribution.

The evaluation incorporated nine integrated scenarios in order to capture variations in the operating environments that would affect potential retirement of the units. The nine cases were developed around uncertainty in fuel prices and CO_2 legislation. The CO_2 scenarios were Existing (current policies only), Moderate ($10/ton), and Substantial ($20/ton). The $10/ton and $20/ton CO_2 penalties were modeled in 2010 dollars, starting in 2015 and escalated at 5% above inflation thereafter. These CO_2 prices were coupled with three fuel scenarios (low, moderate, and high) that were differentiated by assumptions about natural gas supply in the United States.

Plant Daniel Units 1 and 2

The purpose of the Plant Daniel evaluation was to determine the economic benefits of retiring Daniel Units 1 and 2 in December 2014 and replacing the units with the lowest cost option. The evaluation included estimates of transmission cost implications. The economic

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analysis retired and replaced Gulf's ownership portion of Daniel Units 1 and 2 with one 2x1 MHI GAC series combined cycle, avoiding the Daniel Units 1 and 2 SCRs in the fall of 2018 and the fall of 2017, respectively, and the fall 2015 scrubber installations. It was assumed in this study that the replacement CC would be placed on the Plant Crist site. Due to permitting and construction lead time constraints, the Plant Crist CC could not be online until 2018. Therefore, market replacement capacity and energy purchases were assumed from January 2015 until the replacement unit is available.

A transmission study was performed which concluded there were significant costs associated with retiring Gulf's ownership portion of Daniel Units 1 and 2 and replacing the units with a CC at Plant Crist. The cost of transmission improvements required to place the Crist CC in service in 2018 is projected to be approximately $ [redacted]

Results

An economic evaluation of the Plant Daniel CC replacement option was performed to compare customer costs from 2012-2041. The CC replacement option was compared to the cost of continuing to operate Gulf's ownership portion of Plant Daniel Units 1 and 2 with SCRs and scrubbers. Table 3.3-1 presents the NPV customer costs resulting from a comparison of costs of a replacement combined cycle unit minus Gulf's 50% ownership cost to continue to operate Daniel Units 1 and 2 with SCRs and scrubbers.

It shows that for eight of the nine scenarios considered, it is more beneficial to Gulf's customers to retrofit Plant Daniel Units 1 and 2, as proposed, rather than replacing them with a CC unit. In addition, transmission upgrades have long lead times due to permitting and construction limitations; therefore, market purchases for a 2015 replacement would be necessary. Even without monetizing the fuel diversity benefits of retaining coal generation on its system, the analysis shows that the proposed retrofit of the Plant Daniel Units is preferable to their replacement.

Table 3.3-1
Net Replacement Costs – Daniel Units 1 and 2
NPV* 2012 in millions

Fuel/CO_2	Existing CO_2	Moderate CO_2	Substantial CO_2
High	[redacted]	[redacted]	[redacted]
Moderate	[redacted]	[redacted]	[redacted]
Low	[redacted]	[redacted]	[redacted]

***Reflects Gulf ownership portion only**

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4.0 PLANT-BY-PLANT COMPLIANCE PROGRAM

4.1 PLANT CRIST

Plant Crist is a four-unit, coal-fired electric generating facility located just north of Pensacola, Florida. Three older natural gas and oil-fired units at the site have been retired. Units 4 and 5 each have a nameplate rating of 93.75 MW and Units 6 and 7 have nameplate ratings of 370 MW and 578 MW, respectively. All four units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. All four units are equipped with low-NOx burner systems. Plant Crist Units 4, 5, and 6 have SNCR systems, while Crist Unit 7 is equipped with an SCR system for NOx control. The Crist Unit 6 SNCR will be replaced with a SCR system during late April, 2012.

The Plant Crist Units 4 through 7 flue gas desulfurization (FGD) scrubber became operational in December 2009 and is designed to reduce SO_2 emissions by approximately 95%. With these reductions, Gulf Power will be able to reasonably manage compliance with its SO_2 allowance bank. With the completion of the Crist Units 4 through 7 scrubber, the plant now has the option of burning a higher sulfur coal. Mercury emissions are also expected to be reduced through the co-benefits of the scrubber and SCR installations.

4.1.1 Plant Crist Retrofit Options

Plant Crist Unit 6 SCR Project

The Plant Crist Unit 7 SCR became operational in 2005, significantly reducing emissions of NOx from the plant. This project was called for under an agreement with the FDEP. The agreement also called for additional NOx reductions on Plant Crist Units 4 through 6 up to and including an SCR for Unit 6. The Crist Unit 6 SCR is on schedule to be placed in service during late April 2012. The majority of the associated structural steel and ductwork erection is now complete. All three layers of catalyst have been set in place. The project is in its final phase of construction which includes tying in the SCR ductwork to the unit, installing larger capacity induced draft fans to handle the increased draft demand, and the testing and startup of all remaining equipment and systems.

4.1.2 Plant Crist Comparison of Retrofit versus Retirement and Replacement

During 2011, an analysis was run to determine the economic benefits of retiring Plant Crist Unit 6 in December 2014 and replacing the unit with the lowest cost option. The site specific analysis focused on a comparison of continued operation versus unit replacement by a combined cycle. This evaluation included refined commitment and energy value modeling and cost implications to the transmission system. Changes in energy value, capital and other fixed costs were captured in the comparison analysis to help determine the most economical option. The economic results showed that for the twelve scenarios considered, it was more

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beneficial to Gulf's customers to continue to operate Crist Unit 6 with the SCR installed rather than replacing Crist Unit 6 with a CC unit.

4.1.3 Plant Crist MATS Requirements

Gulf is continuing its efforts to evaluate potential MATS compliance options for Plant Crist. The Plant Scholz mercury monitor has been relocated to Plant Crist in order to further analyze Plant Crist mercury emissions. Compliance with the MATS rule may require additional emission controls such as dry sorbent injection and/or a baghouse, changing fuel sources for certain existing units, the addition of new generating resources, and/or transmission upgrades.

4.1.4 Conclusions for Plant Crist

Based on previous economic assessments of Crist Units 4 through 7 and the Crist Unit 6 economic evaluation, the retrofit of Crist Units 4 through 7 with a single FGD scrubber and SCRs on Units 6 and 7 are the best options for compliance with the current requirements of CAIR, CAVR, and the anticipated NAAQS. These are the only technologies that offer the necessary emission reductions for SO_2 and NOx, and when used together, the scrubber and the SCRs on Units 6 and 7 will provide some additional benefit by reducing mercury emissions. Decisions regarding Gulf's CAIR compliance strategy were made jointly with the CAVR and CAMR compliance plans due to co-benefits of proposed controls. In response to finalization of the MATS rule and revisions to the CSAPR, these plans are being evaluated for compliance with the new standards and plans will be revised accordingly.

4.2 PLANT DANIEL

Gulf Power's ownership interest at Plant Daniel is associated with two coal-fired electric generating units that each have a nameplate rating of 548.25 MW. Gulf Power and Mississippi Power Company each own 50 percent of Daniel Units 1 and 2. The plant is operated by Mississippi Power employees. The facility is located just north of Pascagoula, Mississippi, with direct transmission access across Alabama and into Florida. Both coal-fired units were affected by the Acid Rain Program and have operated on low-sulfur coals since the 1990s. These New Source Performance Standards (NSPS) units are relatively low NOx emitters, and as a result, Gulf and Mississippi Power have been able to delay installation of controls and associated costs required under the Acid Rain Program. Low NOx burners were installed on Daniel Units 1 and 2 during 2010 and 2008, respectively, for CAIR annual and seasonal NOx cap and trade allowance programs.

For compliance with the CAIR/CSAPR, CAVR, MATS and anticipated NAAQS Plant Daniel Units 1 and 2 need significant emission reductions. Only a few technologies have demonstrated the ability to provide the needed SO_2 and NOx emission reductions at the commercial scale required for the coal units at Plant Daniel. An assessment was conducted on Plant Daniel Units 1 and 2 to compare retrofit controls versus retirement and replacement options for compliance. As noted under Section 3.2, complete reliance on fuel switching and

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allowance purchases were eliminated as viable options for all of Gulf Power's units, including its share of Plant Daniel Units 1 and 2. Retrofit options, as well as retirement and replacement options, are each reviewed below specifically for Plant Daniel.

4.2.1 Plant Daniel Retrofit Options

Plant Daniel Unit 1 and Unit 2 Flue Gas Desulfurization Scrubber Projects

Very high levels of SO_2 emission reductions can be achieved by flue gas desulfurization. Other than flue gas desulfurization, there are no other commercially available options for SO_2 emission reductions at the level needed to assure compliance with the CAIR/CSAPR, CAVR, and the anticipated NAAQS. Flue gas desulfurization, or wet scrubbing, has been determined to be the only viable SO_2 retrofit compliance option for Plant Daniel.

The Daniel scrubber projects are designed to reduce SO_2 emissions by approximately 95%. With these reductions, Gulf Power will be able to reasonably manage compliance using its SO_2 allowance bank. The scrubber projects are currently scheduled for completion in the fall of 2015. The scrubbers will minimize reliance on the SO_2 allowance market and assist Plant Daniel in complying with the MATS rule.

Plant Daniel NOx Reduction Projects

The Daniel Unit 1 and 2 Low NOx burners were planned for CAIR annual and seasonal NOx cap and trade allowance programs. The Daniel Unit 2 Low NOx burners were installed during 2008 and the Unit 1 Low NOx burners were placed in-service in 2010.

The Plant Daniel Units 1 and 2 SCRs are planned for operation in 2017 and 2018 to help meet the requirements of the CAIR/CSAPR, CAVR, and the anticipated NAAQS. The SCRs, along with the Unit 1 and 2 scrubbers, also provide a co-benefit of reducing mercury emissions.

4.2.2 Plant Daniel Comparison of Retrofit versus Retirement and Replacement

Selection between retrofit and retirement/replacement options for Plant Daniel was based upon a financial assessment and analysis to determine the least cost option for Gulf Power and its customers. The analysis examined the relative cost of (a) completing the retrofit projects and operating the retrofitted unit to (b) retiring the Daniel units without making the retrofit and instead, replacing them with capacity from another generation source. This analysis was completed using a detailed site specific methodology, as previously discussed in Section 3.3.4. The economic analysis retired and replaced Gulf's ownership portion of Daniel Units 1 and 2 with one 2x1 MHI GAC series combined cycle, avoiding the Daniel Units 1 and 2 SCRs in the fall of 2018 and the fall of 2017, respectively, and the fall 2015 scrubber installations. This evaluation included refined commitment and energy value modeling and cost implications to the transmission system. Changes in energy value, capital and other fixed costs were captured in the comparison analysis to help determine the most

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economical option. The economic results showed that for eight of the nine scenarios it would be more beneficial to Gulf's customers to retrofit Plant Daniel Units 1 and 2, rather than replacing them with a CC unit.

4.2.3 Plant Daniel MATS Requirements

Gulf and Mississippi Power are continuing efforts to evaluate potential MATS compliance options for Plant Daniel. It is anticipated that mercury continuous emission monitoring systems and/or additional emissions testing will be needed for Plant Daniel. It is possible that additional emissions controls such as calcium bromide injection may be required.

4.2.4 Conclusions for Plant Daniel

Based on this assessment, the retrofit of Daniel Units 1 and 2 with flue gas desulfurization scrubbers, the installation of Low-NOx combustion controls, and the addition of SCRs on both units are the best options for compliance with the current CAIR/CSAPR, CAVR, and the anticipated NAAQS. These technologies offer the necessary emission reductions for SO_2 and NOx, and when used together, the scrubbers and the SCRs will provide some additional benefit by reducing mercury emissions. Fuel switching alone will not reduce emissions to the required level. Allowance purchases are too uncertain and risky as a sole compliance option. The economic analysis indicated that retirement and replacement of Gulf's ownership portion of the units with a combined cycle unit is not economically feasible relative to retrofit of the existing units under eight of the nine scenarios analyzed.

4.3 PLANT SMITH

Plant Smith includes two coal-fired electric generating units (Unit 1 and Unit 2) along with an oil-fired combustion turbine and a natural gas-fired combined cycle unit. The facility is located just north of Panama City, Florida. Plant Smith Unit 1 has a nameplate rating of 149.6 MW, and Unit 2 has a nameplate rating of 190.4 MW. Both coal-fired units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. Both units are also equipped with low-NOx combustion systems. Unit 1 has special low-NOx burner tips, and Unit 2 has low-NOx burners and separated overfired air.

Installation of SNCRs for Plant Smith Units 1 and 2 were needed for Phase I CAIR compliance in 2009. In addition to CAIR compliance, the SNCRs were needed to assist in maintaining local compliance with the anticipated 8-hour ozone non-attainment designation. The Smith Unit 2 SNCR was placed in-service in the fall of 2008, and the Smith Unit 1 SNCR was placed in-service during May of 2009.

For CAIR and CAVR requirements at Plant Smith, an economic assessment was conducted to compare retrofit controls versus retirement and replacement options for compliance. As noted under Section 3.2, exclusive reliance on fuel switching and allowance purchases were

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eliminated as viable options for Gulf Power. Retrofit options and retirement and replacement options are each reviewed below specifically for Plant Smith.

4.3.1 Plant Smith Retrofit Options

Plant Smith Units 1 and 2 Flue Gas Desulfurization Scrubber Project

The Plant Smith scrubber project has been included in the Gulf Power environmental compliance program because the requirements of CAVR will likely lead to a scrubber being required for Plant Smith Units 1 and 2. This decision is based upon anticipated CAVR command and control requirements. In addition, the scrubber will provide the added benefit of reducing mercury and other hazardous air pollutant emissions. The schedule and decisions about the Plant Smith scrubber remain very flexible. This scrubber would offer the same benefits as the scrubbers previously discussed.

Plant Smith Unit 2 Baghouse

The Plant Smith Unit 2 baghouse project has been included in the Gulf Power environmental compliance program because the MATS rules will likely lead to additional emission controls being required for Plant Smith. The schedule and decisions about the Plant Smith Unit 2 baghouse remain very flexible. Gulf is currently evaluating potential MATS compliance options for Plant Smith. Compliance with this rule is likely to require substantial capital expenditures and compliance costs at the Company's facilities. These costs may arise from unit retirements, installation of additional emission controls, changing fuel sources for certain existing units, the addition of new generating resources, and/or upgrades to the transmission system.

4.3.2 Plant Smith Comparison of Retrofit versus Retirement and Replacement

The Plant Smith economic analysis has not been updated because Gulf has not made any changes to the Plant Smith compliance strategy, other than delaying completion of the mercury monitor installation. In addition, the majority of the expenditures for Phase I environmental projects at Plant Smith were incurred prior to 2009. An updated analysis will be performed before Gulf would consider moving forward with the Plant Smith scrubber and baghouse projects. Both of these projects are included in Phase II of Gulf's compliance program and have not yet been approved for ECRC recovery.

4.3.3 Plant Smith Emission Monitoring and MATS Requirements

The CAIR required the installation of a parametric emission monitoring system on the Plant Smith combustion turbine during 2007. Gulf will continue to incur future maintenance expenditures to ensure accurate accounting of the combustion turbine emissions. Gulf is currently evaluating potential MATS compliance options for Plant Smith.

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4.3.4 Conclusions for Plant Smith

The retrofit of Smith Units 1 and 2 with SNCRs, a FGD scrubber, and a baghouse on Unit 2 were the best options for compliance with CAIR, CAVR, and the CAMR regulations as described in Gulf's original Compliance Plan evaluations. These technologies offered the necessary emission reductions for SO_2, NOx, and mercury. Fuel switching alone would not reduce emissions to the required level. Allowance purchases were too uncertain and risky as a sole compliance option.

The Smith Unit 2 SNCR was placed in-service in the fall of 2008 and the Smith Unit 1 SNCR was placed in-service during May of 2009. The schedule and decisions regarding the Plant Smith scrubber and baghouse, Phase II projects, remain very flexible. These projects are included in Gulf's compliance program for future consideration. Decisions regarding Gulf's CAIR compliance strategy were made jointly with the CAVR and CAMR compliance plans due to co-benefits of proposed controls. In response to finalization of the MATS rule and revisions to the CSAPR, these plans are being evaluated for compliance with the new standards and plans will be revised accordingly.

4.4 PLANT SCHOLZ

Plant Scholz consists of two coal-fired electric generating units that each have a nameplate rating of 49 MW. The facility is located in Jackson County, Florida. Both units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. Because these units are small and older, NOx averaging was used to achieve compliance with the NOx requirements under the Acid Rain Program without the installation of emission control equipment.

For CAIR and CAVR requirements at Plant Scholz, a thorough assessment was conducted to compare retrofit controls versus retirement and replacement options for compliance. Fuel switching, allowance purchases, and emission control retrofit versus retirement and replacement were all evaluated as options for compliance. Because this small plant is nearing retirement, significant investments in capital equipment to reduce emissions cannot be justified economically. The plant will utilize Company wide allowance trading options rather than installing additional emission control equipment for CAIR compliance.

4.4.1 Plant Scholz Emission Monitoring and MATS Requirements

The Scholz mercury emission monitoring system was being installed during February of 2008 when the court issued an opinion vacating the CAMR. Gulf completed the Scholz installation but postponed certification of the system due to pending regulatory uncertainty. The Plant Scholz mercury monitor has recently been relocated to Plant Crist in order to analyze the Plant Crist mercury emissions. Gulf is currently evaluating potential MATS compliance options for Plant Scholz. Compliance with the MATS rule may require unit retirements, additional emission controls, changing fuel sources for certain existing units, and/or the addition of new generating resources.

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4.4.2 Conclusions for Plant Scholz

For CAIR compliance, Plant Scholz will utilize Company wide allowance trading options rather than installing additional emission control equipment. Decisions regarding Gulf's CAIR compliance strategy were made jointly with the CAVR and CAMR compliance plans due to co-benefits of proposed controls. In response to finalization of the MATS rule and revisions to the CSAPR, these plans are being evaluated for compliance with the new standards and plans will be revised accordingly.

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5.0 POTENTIAL NEW ENVIRONMENTAL REGULATIONS

5.1 OZONE STANDARD

The EPA regulates ground level ozone through implementation of an eight-hour ozone air quality standard. In March 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard, but the rule was challenged in court and was held in abeyance while EPA reconsidered the rule. On January 6, 2011, EPA proposed more stringent revisions to the 2008 eight-hour ozone ambient air quality standard, but the EPA Administrator deferred reconsideration of the standard during September 2011. EPA is expected to finalize a new eight-hour ozone standard in the 2014 timeframe, with state implementation plans for any non-attainment areas due in 2017.

5.2 NATIONAL AMBIENT AIR QUALITY STANDARDS

The EPA is scheduled to set new designation areas for the revised 2010 SO_2 and NO_2 primary NAAQS in mid-2012. Although there are no NO_2 designation issues expected in the Company's service area, it is likely that at least one county will be designated non-attainment for SO_2. The EPA will continue reviewing the SO_2 and NO_2 NAAQS under the normal five-year review cycle.

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

5.3 GLOBAL CLIMATE ISSUES

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

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these

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programs would be applied to stationary sources, including power plants. The Tailoring Rule requires new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units and greenhouse gas emissions guidelines for existing sources in late 2012.

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

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

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company system's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units.

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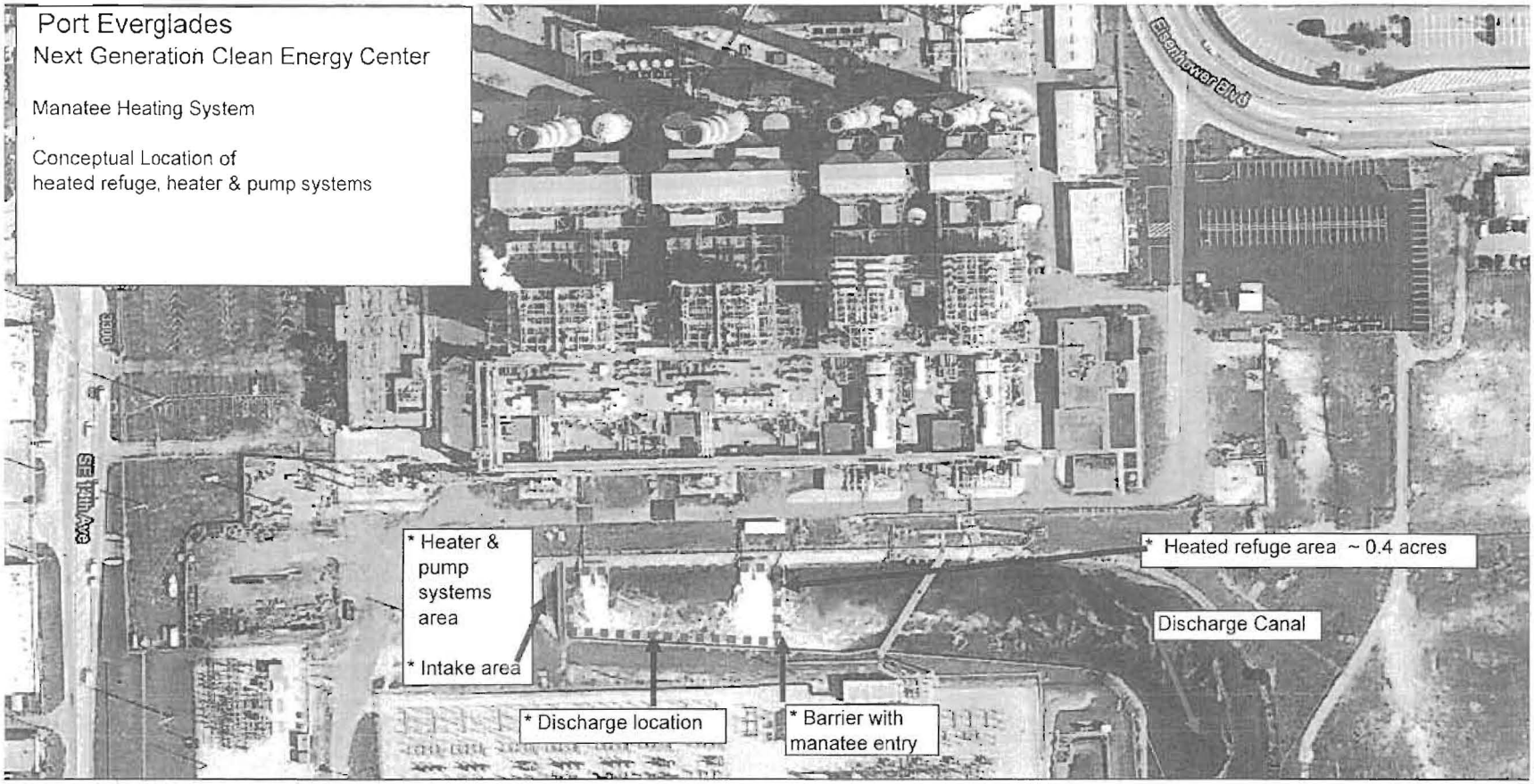
FLORIDA POWER & LIGHT COMPANY

PORT EVERGLADES MANATEE HEATING SYSTEM CONCEPTUAL LOCATION OF HEATED REFUGE, HEATER AND PUMP SYSTEMS

RRL-1
DOCKET NO. 120007-EI
EXHIBIT _____
PAGES 1 OF 2

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	**EXHIBIT**	3
PARTY	Florida Power & Light Co.		
DESCRIPTION	R.R. BaBauve (RRL-1); Port EvergladesManatee Heating System, Loc. of heat and pump syst.		



* Final details of barrier with manatee entry, intake, heater & pump systems, discharge & interconnecting piping locations will be determined during detailed design of the system.

FLORIDA POWER & LIGHT COMPANY

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION ("FDEP")
INDUSTRIAL WASTEWATER FACILITY PERMIT NUMBER FL0001538 FOR PPE

RRL-2
DOCKET NO. 120007-EI
EXHIBIT _____
PAGES 1 OF 70

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	**EXHIBIT**	4
PARTY	Florida Power & Light Co.		
DESCRIPTION	R.R. BaBauve (RRL-2) FDEP Permit No. FL 0001538 for PPEE		

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

JUL 29 2010

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by:

Mr. Rudy Sanchez
Plant General Manager
Florida Power & Light Company (FPL)
P.O. Box 13118
Ft Lauderdale, Florida 33316

PA File No. FL0001538-007-IW1S
Broward County
Port Everglades Plant
NPDES Permit No. FL0001538

NOTICE OF PERMIT ISSUANCE

Enclosed is Permit Number FL0001538 to Florida Power & Light Company, authorizing wastewater discharge from the Port Everglades Plant to the Intracoastal Waterway, a Class III marine water, issued under Section 403.0885, Florida Statutes, and DEP Rule 62-620, Florida Administrative Code.

Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any.

Any party to this order (permit) has the right to seek judicial review of the permit action under Section 120.68, Florida Statutes, by the filing of a notice of appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when this document is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Janet G. Llewellyn
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52, Florida Statutes, with the designated deputy clerk, receipt of which is hereby acknowledged.

G. Shields 07-27-10
Clerk Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this DOCUMENT AND ATTACHMENTS and all copies were mailed before the close of business on 07-27-10 to the listed persons.

G. Shields 07-27-10
Name Date

Certified copies furnished to:
Mark Nuhfer, NPDES Permitting Section, EPA Region 4, Atlanta, GA
Chairman, Board of Broward County Commissioners
Ron Mezich, FWC Tallahassee
Jim Valade, U.S. Fish & Wildlife Service

Copies furnished by U.S. mail to:
Andy Flajole, Florida Power and Light

Copies furnished by intradepartmental mail to:
Justin Wolfe, Esq., DEP Tallahassee
Tim Powell, P.E., DEP West Palm Beach
Michael Hambor, DEP West Palm Beach

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Florida Power & Light Company
P.O. Box 13118
Ft. Lauderdale, FL 33316

PERMIT NUMBER: FL0001538 (Major)
FILE NUMBER: FL0001538-007-IW1S
ISSUANCE DATE: July 22, 2010
EXPIRATION DATE: July 21, 2015

RESPONSIBLE OFFICIAL:

Mr. Jeff Smith
Plant General Manager
P.O. Box 13118
Ft. Lauderdale, Florida 33316
(954) 527-3601

FACILITY:

Florida Power & Light Company
Port Everglades Plant
8100 Eisenhower Blvd
Fort Lauderdale, FL 33316
Broward County
Latitude: 26°5' 5.97" N Longitude: 80°7' 31.87" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.) and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. The above named permittee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:
The facility is an electric generating plant with a total nominal generating capacity of approximately 1200 megawatts (MW), with a total production capacity of 1254 MW using natural gas or oil as fuel. The existing generating facility consists of four dual-fired steam electric generating units (Units 1, 2, 3, and 4) with nameplate ratings of 200 MW, 200 MW, 400 MW, and 400 MW, respectively. Seawater from Port Everglades harbor slip #3 is drawn into the facility's intake canal for use as once-through cooling water which discharges via the facility's discharge canal to the Intracoastal Waterway.

WASTEWATER TREATMENT:
Various wastewater streams generated at the facility include once-through cooling water, sluice water, economizer hopper wash, boiler blowdown, reverse osmosis concentrate, air preheater wash, dust collector wash, equipment wash, boiler fireside wash, stack wash and water treatment system effluent streams. The low volume wastewater treatment system includes a solids settling basin, precipitation basin, percolation basin and their overflow areas. The solids settling and precipitation basins are lined with an impermeable liner and the percolation basin has a limestone bottom. The equipment area runoff treatment system is designed to collect and retain the first inch of rainfall that falls on the plant's equipment area, minimal flows from the service water rinses in the power block area, and boiler blowdown as an infrequent alternate flow. Drainage from areas subject to oil contamination is routed through oil/water separators or oil traps. Runoff in excess of the first inch may be routed to the discharge canal.

REUSE OR DISPOSAL:

Surface Water Discharge D-001: An existing 1228 MGD Annual Average Daily Flow (1295 MGD Maximum Daily Flow) permitted discharge to Intracoastal Waterway, Class III Marine Waters, (WBID 3226G3). The Point of Discharge (POD) into waters of the State is located at a cross-section through the discharge canal 600 feet downstream from the Unit 1 cooling water discharge structure. The point of discharge is located approximately at latitude 26° 05' 01" N, longitude 80° 07' 26" W.

PERMITTEE:	Florida Power and Light	PERMIT NUMBER:	FL0001538 (Major)
FACILITY:	Port Everglades Power Plant	EXPIRATION DATE:	July 21, 2015

Surface Water Discharge D-00B3: An existing discharge to the Intracoastal Waterway, Class III Marine Waters, (WBID 3226G3). The East Tank Farm Stormwater point of discharge is located approximately at latitude 26° 04' 59" N, longitude 80°7' 20" W.

Land Application R-001: An existing land application system consisting of Percolation Basin (Basin B-2) located approximately at latitude 26° 04' 59" N, longitude 80°7' 32" W.

Land Application R-002: An existing land application system consisting of Stormwater Basin (Basin B-5) located approximately at latitude 26° 05' 00" N, longitude 80°7' 28" W.

Internal Outfall I-019: An existing discharge to the intake canal, Class III Marine Waters, (WBID 3226G3). The point of discharge is located approximately at latitude 26° 05' 10" N, longitude 80° 07' 32" W.

Internal Outfall I-01B1: An existing discharge to the discharge canal and ultimately to the Intracoastal Waterway, Class III Marine Waters, (WBID 3226G3). The Stormwater Forwarding Basin and Sump (B5/S-11) point of discharge is located approximately at latitude 26° 05' 01" N, longitude 80° 07' 29" W.

Internal Outfall I-012: An existing permitted discharge to the intake canal.

Internal Outfall I-016: An existing permitted discharge to the intake canal.

Internal Outfall I-111: An existing 230 MGD Daily Maximum Flow permitted discharge to the discharge canal.

Internal Outfall I-112: An existing 230 MGD Daily Maximum Flow permitted discharge to the discharge canal.

Internal Outfall I-113: An existing 396 MGD Daily Maximum Flow permitted discharge to the discharge canal.

Internal Outfall I-114: An existing 396 MGD Daily Maximum Flow permitted discharge to the discharge canal.

Internal Outfall I-181, I-182, I-183, I-184: Existing permitted discharges from the auxiliary equipment cooling water systems for Units 1, 2, 3, and 4 to the discharge canal, respectively.

Internal Outfall I-1B2: An existing permitted discharge to the intake canal.

Internal Outfall I-1D1, I-1D2, I-1D3, I-1D4: An existing permitted discharge to the discharge canal.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 30 of this permit.

PERMITTEE: Florida Power and Light
FACILITY: Port Everglades Power Plant

PERMIT NUMBER: FL0001538-007 (Major)
EXPIRATION DATE: Draft

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge boiler blowdown, once-through non-contact cooling water, auxiliary equipment cooling water, reverse osmosis reject water, intake screen wash water, and stormwater from Outfall D-001 to the Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Oxidants, Total Residual	mg/L	Max Max	0.01 0.01	Monthly Average Daily Maximum	Bi-weekly	Grab	EFF-5	See I.B.10
Temperature, Water	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	Bi-weekly	Instantaneous	EFF-5	
Aluminum, Total Recoverable	mg/L	Max Max	1.5 1.5	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Arsenic, Total Recoverable	ug/L	Max Max	36 36	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Cadmium, Total Recoverable	ug/L	Max Max	9.3 9.3	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Copper, Total Recoverable	ug/L	Max Max	3.7 3.7	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5 SWB-1	See I.A.5
Oxygen, Dissolved (DO)	mg/L	Max Min	Report Report	Monthly Average Daily Minimum	Semi-Annually	Grab	EFF-5	See I.A.6
Fluoride, Dissolved (as F)	mg/L	Max Max	5.0 5.0	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Iron, Total Recoverable	mg/L	Max Max	0.3 0.3	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Lead, Total Recoverable	ug/L	Max Max	5.6 5.6	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Mercury, Total Recoverable	ug/L	Max Max	0.025 0.025	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Nickel, Total Recoverable	ug/L	Max Max	8.3 8.3	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5 SWB-1	See I.A.5
Selenium, Total Recoverable	ug/L	Max Max	71 71	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Zinc, Total Recoverable	ug/L	Max Max	86 86	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Chronic Whole Effluent Toxicity, 7-Day IC25 (Mysidopsis bahia)	percent	Min	100	Single Sample	Quarterly	24-hr FPC	EFF-5	See I.A.4
Chronic Whole Effluent Toxicity, 7-Day IC25 (Menidia beryllina)	percent	Min	100	Single Sample	Quarterly	24-hr FPC	EFF-5	See I.A.4

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
EFF-5	600 feet downstream from the Unit 1 discharge structure physically demarcated by oil spill boom across the discharge canal.
SWB-1	Background from intake canal at a point upstream (North) of outfalls I-012 and I-016.

3. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

4. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from outfall D-001.

   a. Effluent Limitation
      (1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. *[Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]*
      (2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. Acute whole effluent toxicity testing is not required except as provided in 4.g.(4). *[Rules 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]*

   b. Monitoring Frequency
      (1) Routine toxicity tests shall be conducted once every three months, the first starting within 60 days of the issuance date of this permit and lasting for the duration of this permit.
      (2) Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation in 4.a.(1) above, the permittee may submit a written request to the Department for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 4.a.(1) above.
      (3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-014, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive valid tests for the purpose of evaluating the reduction of monitoring frequency.

   c. Sampling Requirements
      (1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-014, Section 8.
      (2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.
      (3) Samples for routine and additional follow-up tests shall not be collected on the same day.

   d. Test Requirements
      (1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: **100%, 50%, 25%, 12.5%,** and **6.25%** final effluent.
      (2) The permittee shall conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, **Americamysis (Mysidopsis) bahia,** Method 1007.0, and an inland silverside, **Menidia beryllina,** Method 1006.0, concurrently.
      (3) All test species, procedures and quality assurance criteria used shall be in accordance with **Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms**, 3rd Edition, EPA-821-R-02-014. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In the event the above method is revised, the permittee shall conduct chronic toxicity testing in accordance with the revised method.
      (4) The control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows;
         (a) For the **Americamysis bahia** bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(b) For the **Menidia beryllina** bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(c) If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements

(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.

(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-014, Section 14.12 (**Americamysis bahia**) and Section 13.12 (**Menidia beryllina**). The repeat test shall begin within 21 days after the last day of the invalid test.

(3) If 100% mortality occurs in all effluent concentrations for either species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.

(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-014, Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements

(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:

(a) Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.

(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.

(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.

(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.

(5) The same bioassay data shall not be reported as the results of more than one test.

(6) All bioassay laboratory reports shall be sent to:
Florida Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, Florida 33401

g. Test Failures

(1) A test fails when the test results do not meet the limits in 4.a.(1).

(2) Additional Follow-up Tests:

(a) If a routine test does not meet the chronic toxicity limitation in4.a.(1) above, the permittee shall notify the Department at the address above within 21 days after the last day of the failed routine test

and conduct two additional follow-up tests according to 4.d. on each species that failed the test on each species that failed the test in accordance with 4.d.

(b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.

(c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permittee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-014.

(3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permittee shall notify the Department within 21 days after the last day of the third test failure.

(a) The permittee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.

(b) The Department shall review and approve the plan before initiation.

(c) The plan shall be initiated within 30 days following the Department's written approval of the plan.

(d) Progress reports shall be submitted quarterly to the Department at the address above.

(e) During the implementation of the plan, the permittee shall conduct quarterly routine whole effluent toxicity tests in accordance with 4.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 4.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-014, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.

(f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 4.a.(1) above, the permittee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests.
If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.

(4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 4.a.(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.

(5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

5. The actual limit shall be the water quality standard set forth in Rule 62-302.530, F.A.C. for Class III Marine waters as specified here or the concentration of the intake cooling water, whichever is greater. If the Outfall D-001 sample exceeds the intake concentration (and the intake concentration exceeds the water quality standard), the concentration of a minimum of five (5) additional subsamples shall be analyzed from the original intake and outfall samples. The results shall be evaluated using the "student's t-test" comparing discharge concentrations with the intake concentrations. Unless the discharge concentration exceeds the intake concentration at the 95% confidence level, the facility shall be in compliance with the limitation.

6. Dissolved Oxygen (DO) concentration shall not be less than DO measured at intake monitoring location INT- 1, 2, 3, and 4, unless the intake DO is greater than the applicable Water Quality Criteria (WQC) in Rule 62-302.530(31), F.A.C., in which case the discharge limitation shall be the WQC. A measurement tolerance of 0.5 mg/L shall be allowed for DO field measurements.

7. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge stormwater from **Outfall D-00B3 (East Tank Farm)** to the Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Average Daily Maximum	Weekly	Calculated	FLW-12	
Petrol Hydrocarbons, Total Recoverable	mg/L	Max Max	5.0 5.0	Daily Average Daily Maximum	Monthly	Grab	EFF-9	
Turbidity	NTU	Max	Report Report	Single Sample Single Sample	Monthly	Grab	SWB-1 EFF-9	See I.A.10
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Daily Average Daily Maximum	Monthly	Grab	EFF-9	
pH	s.u.	Max Min Max Min	Report Report Report Report	Daily Maximum Daily Minimum Daily Maximum Daily Minimum	Monthly	Grab	SWB-1 SWB-1 EFF-9 EFF-9	See I.A.11

8. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.7. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-12	Calculated based on pump rates and duration of pumping.
EFF-9	Nearest accessible point after final treatment but prior to actual discharge or mixing with the receiving waters.
SWB-1	Background from intake canal at a point upstream (North) of outfalls I-012 and I-016.

9. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. [62-302.500(1)(a)]

10. The limit for "Turbidity" shall be calculated as follows:

    Limit = Background Turbidity + 29 NTU

    The measured effluent value shall be recorded on the DMR in the parameter row for "Turbidity (effluent)." The measured background value shall be recorded on the DMR in the parameter row for "Turbidity (background)" The calculated effluent limit shall be recorded on the DMR in the parameter row for "Turbidity (calculated limit)." Compliance with the effluent limitation is determined by calculating the difference between the measured effluent value and the calculated. The compliance value shall be recorded on the DMR in the parameter row for "Turbidity (effluent minus calculated limit)." The compliance value shall not exceed 0.00. *[62-302.530(69)]*

11. Discharge pH shall not vary more than one unit above or below natural background, as defined in Rules 62-302.200(15) and 62-302.530(51)(c), F.A.C., provided that the pH is not lowered to less than 6.0 units or raised above 8.5 units. If natural background is less than 6.0 units, the pH shall not vary below natural background, or vary more than one unit above natural background. If natural background is higher than 8.5 units, the pH shall not vary above natural background or vary more than one unit below natural background.

B. Internal Outfalls

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Water Treatment System Effluent Streams from Internal Outfall I-012** to the intake canal. Such discharge shall be limited and monitored by the permittee as specified:

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FACILITY: Port Everglades Power Plant

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			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Semi-Annually	Calculated	FLW-9	See I.B.3
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-7	See I.B.3
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-7	See I.B.3
pH	s.u.	Min Max	6.0 9.0	Daily Minimum Daily Maximum	Semi-Annually	Grab	EFF-7	See I.B.3

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-9	Calculated based on water treatment system efficiency ratio.
EFF-7	Water treatment system effluent point prior to entering the intake canal.

3. Water treatment system filter backwash and softener regeneration are discharged to the lined solids settling basin. Other water treatment system effluent streams are discharged to the intake canal but may also be discharged to the lined solids settling basin as an alternate disposal method.

4. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Boiler Blowdown from Internal Outfall I-016** to the intake canal. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max	Report	Monthly Average	Daily	Calculated	FLW-10	
Flow, Total Volume	Mgal	Max	Report	Monthly Average	Monthly	Calculated	EFF-6	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Bi-weekly	Grab	EFF-6	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Bi-weekly	Grab	EFF-6	
Hydrazine	mg/L	Max	0.3	Daily Maximum	Per discharge	Grab	EFF-6	See I.B.6
pH	s.u.	Min Max	6.0 9.0	Daily Minimum Daily Maximum	Bi-weekly	Grab	EFF-6	

5. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.4. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-10	Calculated based on representative conductivity measurements.
EFF-6	Boiler blowdown recovery basin outlet prior to discharge to the intake canal.

6. The monitoring frequency for hydrazine shall be once per discharge event. A discharge event is defined as a cold dump of the boiler following maintenance activities or cold stand-by status which requires hydrazine to be added

to the boiler water to achieve concentrations higher than normal for protection of metal surfaces. Boiler blowdown, under normal operating conditions with hydrazine concentrations of 10 to 20 ug/l, may be discharged without limitations or monitoring requirements for hydrazine.

7. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Once-Through Non-Contact Cooling Water (OTCW) from Internal Outfalls I-111, I-112, I-113, and I-114** from Units 1, 2, 3, and 4, respectively, to discharge canal to the Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Continuous	Calculated	FLW-1, 2, 3, 4	See VI.5
Temperature, Water	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	Continuous	Recorder	EFF-1, 2, 3, 4	See I.B.9
Temp. Diff. between Intake and Discharge	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	6/Day	Calculated	INT-1, 2, 3, 4 EFF-1, 2, 3, 4	See I.B.9
Oxidants, Total Residual	mg/L	Max Max	0.20 0.20	Monthly Average Daily Maximum	Weekly	Grab	EFF-1, 2, 3, 4	See I.B.10
Chlorination Duration	min/day	Max	120	Daily Maximum	Daily	Pump logs	INT-1, 2, 3, 4	

8. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.7. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-1, 2, 3, 4	Calculated based on pump performance curves, system head curves and run times for Units 1, 2, 3, and 4, respectively.
EFF-1, 2, 3, 4	OTCW outlets for Units 1, 2, 3, and 4, respectively.
INT-1, 2, 3, 4	OTCW intakes for Units 1, 2, 3, and 4, respectively.

9. Discharge and intake temperatures shall be measured continuously. However, the monthly average and daily average values for discharge temperature and temperature rise shall be determined, during a given calendar month, from daily temperature readings taken at uniform intervals not greater than four hours.

10. Total Residual Oxidants (TRO) means the value obtained using the amperometric titration method for total residual chlorine or the Hach model 19300 or equivalent). Testing for TRO by titration shall be conducted according to either the low-level amperometric method, or the DPD calorimetric method as specified in section 4500-Cl E. or 4500 Cl G., respectively, Standard Methods for the examination of Water and Waste water, 18th Edition (or most current edition).

    The permittee shall collect samples when chlorine is in use. TRO monitoring requirements for either Units 1, 2, 3 or 4 are not applicable for any week in which chlorine is not added to that unit. Monitoring requirements for the point of discharge are not applicable for any week in which chlorine is not added to anyof the units. No more than one unit shall discharge total residual oxidant at any one time.

    Multiple grabs for TRO shall be defined as once per five minutes during TRO discharge periods of 30 minutes or less and once per 15 minutes for periods exceeding 30 minutes with no less than four analyses during the period of TRO discharge (sampling shall be continued until the end of the TRO discharge).

11. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Auxiliary Equipment Cooling Water (AECW) from Internal Outfalls I-**

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1D1, I-1D2, I-1D3, and I-1D4 from Units 1, 2, 3, and 4, respectively, used in lieu of OTCW during periods of Reserve Shutdown or periods of circulation water pump malfunction, to discharge canal to Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Weekly	Calculated	FLW-5, 6, 7, 8	See VI.5
Temp. Diff. between Sample and Upstrm	Deg F	Max Max	20.0 20.0	Monthly Average Daily Maximum	6/Day	Calculated	INT-5, 6, 7, 8 EFF-1, 2, 3, 4	See I.B.13

12. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.11. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-5, 6, 7, 8	Calculated based on pump performance curves, system head curves and run times for Units 1, 2, 3, and 4, respectively.
INT-5, 6, 7, 8	AECW intakes for Units 1, 2, 3, and 4, respectively.
EFF-1, 2, 3, 4	OTCW outlets for Units 1, 2, 3, and 4, respectively.

13. The permittee may notify the Department after one year's data collection in order to request a modification of the permit to include an actual temperature rise limit based on operational data.

14. The permittee shall maintain current travelling screen practices at Units 1, 2, 3and 4 so as to assure that the screens are cycled a minimum of twice during each 24 hours of operation unless precluded by repair /maintenance requirements.

15. The permittee shall develop a plan in accordance with the schedule in Condition VI.6 to help return live fish, shellfish, and other aquatic organisms collected or trapped on the intake screens to their natural habitat. Other material shall be removed from the intake screens and disposed of in accordance with all existing Federal, State and /or local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters.

16. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge equipment and non-equipment area stormwater and boiler blowdown from **Outfall I-01B1** to the Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Per discharge	Calculated	FLW-11	See I.B.19
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Per discharge	Grab	EFF-8	See I.B.19
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Per discharge	Grab	EFF-8	See I.B.19

Hydrazine	mg/L	Max	0.3	Daily Maximum	Per discharge	Grab	EFF-8	See I.B.19 and 20
pH	s.u.	Min Max	6.0 9.0	Daily Minimum Daily Maximum	Per discharge	Grab	EFF-8	See I.B.19

17. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.16 and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-11	Calculated based on water level depth over weir.
EFF-8	The stormwater treatment system effluent point prior to discharge to the discharge canal.

18. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

19. Monitoring for this effluent is not required provided the first 15 minutes of a 10-year, 24-hour rainfall event is collected in the forwarding basin (Basin B-5) and routed to the percolation basin (Basin B-2). Subsequent storm water may be discharged without limitations or monitoring requirements.

20. The discharge limitation and monitoring requirements for hydrazine shall be applicable only during certain periods, i.e., accidental spill or any other event which could introduce hydrazine in concentrations in excess of 20 ug/L to an equipment area floor drain system.

C. **Land Application Systems**

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge process wastewater, boiler blowdown, reverse osmosis reject water, metal cleaning wastewater, and stormwater to **Land Application System R-001, Percolation Basin (Basin B-2)**. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Weekly Maximum Monthly Average	Weekly	Estimated	FLW-13	

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.C.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-13	Treated wastewater flow entering Basin B-2.

3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge stormwater, boiler blowdown, treated equipment area runoff, non-equipment area runoff, and treated miscellaneous service water rinses from the power block area to **Land Application System R-002, Stormwater Basin (Basin B-5)**. Such discharge shall be limited and monitored by the permittee as specified below:

PERMITTEE: Florida Power and Light
FACILITY: Port Everglades Power Plant

PERMIT NUMBER: FL0001538 (Major)
EXPIRATION DATE: July 21, 2015

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Weekly Maximum Monthly Average	Weekly	Calculated	FLW-14	

4. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.C.3. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-14	Treated wastewater flow entering Basin B-5.

D. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in 62-302, F.A.C.; and

   c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

   When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

   Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e. monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in

accordance with the associated DMR due dates below. DMRs shall be submitted for each required monitoring period including months of no discharge.

REPORT Type on DMR	Monitoring Period	Due Date
Monthly or Toxicity	first day of month - last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 - June 30 July 1 - September 30 October 1 - December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 - June 30 July 1 - December 30	July 28 January 28
Annual	January 1 - December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge. The permittee may submit either paper or electronic DMR form(s). If submitting paper DMR form(s), the permittee shall make copies of the attached DMR form(s). If submitting electronic DMR form(s), the permittee shall use a Department-approved electronic DMR system.

The permittee may submit either paper or electronic DMR forms. If submitting paper DMR forms, ~~T~~the permittee shall make copies of the attached DMR form~~(s)~~, without altering the original format or content unless approved by the Department, and shall submit the completed DMR form~~(s)~~ to the Department by the twenty-eighth (28th) of the month following the month of operation at the addresses specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

And

Florida Department of Environmental Protection
Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, FL 33401

[62-620.610(18)]

5. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Southeast District Office at the address specified below:

Southeast District Office
400 N. Congress Avenue, Suite 200
West Palm Beach, FL 33401

Phone Number - (561) 681-6600
FAX Number - (561) 681-6755 (All FAX copies shall be followed by original copies.)

[62-620.305]

6. All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. *[62-620.305]*

7. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

8. The permittee is authorized to discharge from **Internal Outfalls I-181, I-182, I-183, and I-184 - Auxiliary Equipment Cooling** and **Outfall I019 - Intake Screen Washwater**. Sampling and monitoring of these outfalls are not required.

9. The permittee is authorized to discharge from **Outfalls I-1B2 - Stormwater From Diked Petroleum Storage or Handling Areas (North Tank Farm)**, provided such discharges are limited and monitored by the permittee as specified below:

   a. The facility shall have a valid Spill Prevention Control and Countermeasure (SPCC) Plan pursuant to 40 CFR Part 112.

   b. In draining the diked area, a portable oil skimmer or similar device or absorbent material shall be used to remove oil and grease (as indicated by the presence of a sheen) immediately prior to draining.

   c. Monitoring records shall be maintained in the form of a log and shall contain the following information, as a minimum:

      - Date and time of discharge;
      - Estimated volume of discharge;
      - Initials of person making visual inspection and authorizing discharge; and
      - Observed conditions of stormwater discharged.

   d. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of a visible oil sheen at any time.

10. The permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on August 13, 1999 et seq.

11. The use of fluorescein dye at a feed concentration of no greater than 1.0 mg/L is authorized for maintenance and flow testing activities. The facility will maintain an on-site record of the dosage and discharge concentrations, specific application activity, flow rate, and residence time per usage to be available upon request. The dye may be used while other treatment chemicals are present in the water to be dosed.

12. The use of sodium hydroxide and sulfuric acid are authorized for pH control.

13. Sodium phosphate, used to control calcium and magnesium scaling, and ammonium hydroxide, used for pH control, are authorized as boiler water treatment additives.

14. Sodium metabisulfite is authorized for use in the facility's water treatment system for dechlorination of source water prior to being fed to the reverse osmosis (RO) system's membranes. The concentration of sodium metabisulfite in the RO feed water shall be 3 mg/L or less.

15. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be discharged to lakes, rivers, or other waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit. Discharge of chlorine from the use of chlorine gas, sodium hypochlorite, or similar chlorination compounds for treatment of the plant potable and service water systems is authorized.

    A permit revision from the Department shall be required prior to the use of any biocide or chemical additive used in the cooling system (except chlorine or hydrazine as authorized elsewhere in this permit) or any other portion of the treatment system which may be toxic to aquatic life. The permit revision request shall include:
    a. Name and general composition of biocide or chemical
    b. Frequencies of use
    c. Quantities to be used
    d. Proposed effluent concentrations
    e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving

Waters for Freshwater and Marine Organisms, or most current addition.)

f. Product data sheet
g. Product label

Herbicides may be used within basins for the purpose of prevention of over accumulation of aquatic weeds. Use shall be in accordance with labeled instructions. Not later than 90 days after the effective date of this permit, the permittee shall provide the Department with a list of all herbicides used in the previous twelve months. Other products shall not be used without prior approval.

16. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately discharges to waters of the State is prohibited, unless specifically authorized elsewhere in this permit.

17. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. The permittee shall dispose of all known PCB equipment, articles, and wastes in accordance with 40 CFR 761. The permittee shall certify each time that this disposal has been accomplished.

18. There shall be no discharge of floating debris, scum, oil, or other matter in such amounts as to form nuisances or produce color, odor, taste, turbidity, or other conditions to such degree as to create a nuisance or otherwise interfere with the beneficial use of the receiving waters in accordance with Rules 62-302.500(1)(a) and 62-302.530(500)(b), F.A.C. Any such discharges to waters of the State shall be reported to the Department when submitting DMRs.

19. The permittee is authorized to use Nalco 7330 in both of the facility's closed cooling water systems (CCWS). For scheduled maintenance or repair activities requiring drainage of isolated piping and pumps, or complete or partial drainage of a CCWS, the permittee shall not apply Nalco 7330 to that CCWS less than 30 days prior to the scheduled outage. For unscheduled activities requiring immediate attention, such as emergency repairs, in which Nalco 7330 has been applied within the past 30 days, the discharge to stormwater basin B-5 shall be routed to percolation basin B-2, and not discharged via the alternate route through outfall I-01B1. If a discharge of Nalco 7330 containing wastewater from the stormwater forwarding sump S-11 to surface waters via outfall I-01B1 was necessary, toxicity testing and reporting shall be required in accordance with permit condition I.A.4, at the monitoring location designated as EFF-8 and described in permit condition I.A.13. The facility shall maintain a record on-site containing the frequency of use, feed concentration, discharge concentration, application dates, dates of scheduled and unscheduled maintenance and repair activities, volumes of wastewater discharged to the B-5 basin containing Nalco 7330, and route of discharge if applicable, for both CCWSs.

20. The permittee shall maintain the current intake through-screen velocity such that the existing maximum velocity is not exceeded.

II. SLUDGE MANAGEMENT REQUIREMENTS

A. Basic Management Requirements

1. The disposal of sludge or other solids generated from the plant's wastewater treatment and containment system shall be reused, reclaimed, or otherwise disposed of in accordance with the requirements of Chapter 62-701, F.A.C.

2. The permittee shall be responsible for proper treatment, management, use or land application of its sludges.

3. The permittee shall keep records of the amount of sludge or residuals disposed, transported, or incinerated in (Please specify units). If a person other than the permittee is responsible for sludge transporting, disposal, or incineration, the permittee shall also keep the following records:

   a. Name, address and telephone number of any transporter, and any manifests or bill of lading used;
   b. Name and location of the site of disposal, treatment or incineration;
   c. Name, address, and telephone number of the entity responsible for the disposal, treatment, or incineration site.

PERMITTEE: Florida Power and Light
FACILITY: Port Everglades Power Plant

PERMIT NUMBER: FL0001538 (Major)
EXPIRATION DATE: July 21, 2015

III. GROUND WATER REQUIREMENTS

1. The permittee shall give at least 72-hours notice to the Department's Southeast District Office, prior to the installation of any monitoring wells. *[62-620.320(6)]*

2. Prior to construction of ground water monitoring wells, a soil boring shall be made at each monitoring well location in order to properly determine the well depth and screen interval. *[62-520.900(2)]*

3. Within 30 days after installation of a monitoring well, the permittee shall submit to the Department's Southeast District Office detailed information on the well's location and construction on the attached DEP Form(s) 62-520.900(2), Monitor Well Completion Report. *[62-532.410 and 62-520.900(2)]*

4. All piezometers and monitoring wells not part of the approved ground water monitoring plan are to be plugged and abandoned in accordance with Rule 62-532.500(4), F.A.C., unless future use is intended. *[62-532.500(4)]*

5. For land application systems for R-001and R-002, all ground water quality criteria specified in Chapter 62-520, F.A.C., shall be met at the edge of the zone of discharge. The zone of discharge for this project shall extend horizontally to the facility's property line and vertically to the base of the surficial aquifer. *[62-520.200(26)] [62-522.200(10) and 62-520.465]*

6. The ground water minimum criteria specified in Rule 62-520.400 F.A.C., shall be met within the zone of discharge. *[62-520.400 and 62-520.420(4)]*

7. If the concentration for any constituent listed in Permit Condition III.10. in the natural background quality of the ground water is greater than the stated maximum, or in the case of pH is also less than the minimum, the representative background quality shall be the prevailing standard. *[62-520.420(2)]*

8. During the period of operation authorized by this permit, the permittee shall continue to sample ground water at the monitoring wells identified in Permit Condition III.9. below in accordance with this permit and the approved ground water monitoring plan prepared in accordance with Rule 62-520.600, F.A.C. *[62-520.600]*

9. The following monitoring wells shall be sampled for Land Application Systems R-001 and R-002 at Land Application Sites PER-1 and PER-2, respectively.

Monitoring Well ID	Alternate Well Name and/or Description of Monitoring Location	Latitude			Longitude			Depth (Feet)	Aquifer Monitored	New or Existing
		°	'	"	°	'	"			
MWB-01	Monitoring Well NOB-1; west of NW corner for B-1	26	04	59.8	80	07	32.1	23	Surficial	Existing
MWC-01	Monitoring Well NOB-2A; south of SE corner for B-3	26	04	57.5	80	07	35.4	15	Surficial	Existing
MWC-02	Monitoring Well NOB-2B; south of SE corner for B-3	26	04	57.4	80	07	35.3	25	Surficial	Existing
MWC-03	Monitoring Well NOB-3A (NOB-3A-R); south of overflow area for B-3	26	04	57.4	80	07	38.6	15	Surficial	Existing
MWC-04	Monitoring Well NOB-3B1; south of overflow area for B-3	26	04	57.4	80	07	38.5	25	Surficial	Existing
MWC-05	Monitoring Well D-1A; south of SE corner for B-1	26	04	58.3	80	07	27.7	15	Surficial	Existing

MWC = Compliance; MWB = Background; MWI = Intermediate; MWP =Piezometer

[62-520.600]

10. The following parameters shall be analyzed for each monitoring well identified in Permit Condition III.9. Results shall be reported on the permittee's Discharge Monitoring Report in accordance with Condition I.D.3. :

Parameter	Compliance Well Limit	Units	Sample Type	Monitoring Frequency
Water Level Relative to NGVD	Report	Feet	Measured	Quarterly
Solids, Total Dissolved (TDS)	Report	mg/L	Grab	Quarterly
pH	Report	s.u.	In Situ	Quarterly
Sulfate, Total	Report	mg/L	Grab	Quarterly
Iron, Total Recoverable	Report	mg/L	Grab	Quarterly
Manganese, Total Recoverable	Report	mg/L	Grab	Quarterly
Sodium, Total Recoverable	Report	mg/L	Grab	Quarterly
Fluoride, Total (as F)	4.0	mg/L	Grab	Semi-Annually
Arsenic, Total Recoverable	0.010	mg/L	Grab	Semi-Annually
Copper, Total Recoverable	Report	mg/L	Grab	Semi-Annually
Chromium, Total Recoverable	0.1	mg/L	Grab	Semi-Annually
Lead, Total Recoverable	0.015	mg/L	Grab	Semi-Annually
Nickel, Total Recoverable	0.1	mg/L	Grab	Semi-Annually
Silver, Total Recoverable	Report	mg/L	Grab	Semi-Annually
Zinc, Total Recoverable	Report	mg/L	Grab	Semi-Annually

[62-520.600(11)(b)]

11. Water levels shall be recorded before evacuating each well for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NAVD allowable) at a precision of plus or minus 0.01 foot. *[62-520.600(11)(c)]*

12. Ground water monitoring wells shall be purged prior to sampling to obtain representative samples. *[62-160.210]*

13. Analyses shall be conducted on unfiltered samples, unless filtered samples have been approved by the Department's Southeast District Office as being more representative of ground water conditions. *[62-520.310(5)]*

14. Ground water monitoring test results shall be submitted on Part D of Form 62-620.910(10) in accordance with Permit Condition I.D.3. *[62-520.600(11)(b)]*

15. If any monitoring well becomes damaged or inoperable, the permittee shall notify the Department's Southeast District Office immediately and a detailed written report shall follow within seven days. The written report shall detail what problem has occurred and remedial measures that have been taken to prevent recurrence. All monitoring well design and replacement shall be approved by the Department's Southeast District Office prior to installation. *[62-520.600][62-620.320(6)]*

16. An exemption from the Class G-II Ground Water Standard for sodium has been granted to the facility by the Department. The exemption is effective for the duration of this permit.

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

1. Appropriate warning signs shall be posted around the site boundaries to designate the nature of the various settling basins and percolation basins, including the designated overflow areas that comprised the permitted wastewater and stormwater treatment and disposal facility.

2. The bottoms for the settling basins and percolation basins shall be cleaned out periodically, or when necessary, to remove the excess buildup of sediments, and to ensure continuous percolation capability for the percolation basins. The sediments and sludge excavated from the basins must be properly stored onsite, until they are

disposed of in accordance with the requirements in Part II of the permit. Routine weed control and regular maintenance of basin embankments and access areas are required.

3. The permittee shall inspect the conditions for the impermeable liners for the lined settling basins and the percolation basins with lined side slopes. Any liners that display signs of significant deterioration, or evidence of leakage or instability, shall be replaced as soon as practical.

4. A minimum one (1) foot of freeboard should in general be maintained for all the wastewater and stormwater storage, treatment and percolation basins.

5. An existing land application system (R-001) consisting of percolation pond. Land application system R-001 is located approximately at latitude 26° 04' 59" N, longitude 80° 07' 32" W. R-001 is also identified as Percolation Basin B-2. It is located south of the plant switchyard with a dimension of approximately 112 feet long, 82 feet wide and 6.5 feet deep; approximate design capacity of 340,000 gallon; and built with lined side-slopes and a crushed limestone bottom. It is part of the facility's permitted metal cleaning waste/low volume waste treatment and disposal system. And being the downstream-most unit after a sequence of precipitation and settling treatment basins. In addition to handling treated waste streams originating from miscellaneous maintenance activities, non-equipment area runoff (as an alternate discharge route), R.O. water treatment system, metal cleaning waste, boiler process, and boiler blowdown (as an alternate discharge route), it also receives treated stormwater (equipment area runoff) pumped from Stormwater Forwarding Sump S-11. Basin B-2 has an overflow containment area approximately 185 feet by 84 feet by 247 feet by 80 feet. Depth is approximately 4 feet, with a design capacity of 500,000 gallons.

6. An existing land application system (R-002) consisting of percolation pond. Land application system R-002 is located approximately at latitude 26° 05' 00" N, longitude 80° 07' 28" W. R-002 is also identified as Stormwater Forwarding Basin (SWFB) B-5. It is located east of the plant switchyard with dimensions of approximately 282 feet long, 140 feet wide and 7.5 feet deep; a design capacity of approximately 326,000 gallons; and built with lined side-slopes and a crushed limestone bottom. It receives stormwater and miscellaneous plant washdown water from both equipment (primarily the "power block" area) and non-equipment areas. Equipment area runoff is routed through oil/water separators prior to entering Stormwater Forwarding Sump S-11. Boiler blowdown via equipment or non-equipment runoff areas may be a contributing source of wastewater as an alternate discharge route. Excess stormwater entering Sump S-11 may also be diverted to the plant discharge canal via outfall I-01B1 when the system capacity is exceeded.

7. Actual flows into the basins are likely affected by the prevailing weather condition and occurrence of plant maintenance activities. FPL has projected in a report dated May 8, 1991, the percolation capacity for Percolation Basin at 23,700 gpd. At this time, the permitted disposal capacities for the two basins are restricted by their actual demonstrated percolation capabilities instead of other imposed numerical limits. The permitted land application system also includes overflows areas adjacent to Percolation Basin B-2, and that south of Solids Settling Basin (SSB) Basin B-3, that may be utilized in extreme wet weather. Basin B-2 has an overflow containment area approximately 185 feet by 84 feet by 247 feet by 80 feet. Depth is approximately 4 feet, with a design capacity of 500,000 gallons. Basin B-3 has an overflow containment area approximately 233 feet by 261 feet by 162 feet and triangular in shape. Depth is approximately 3 feet with a design capacity of approximately 356,000 gallons.

V. OPERATION AND MAINTENANCE REQUIREMENTS

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of

the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

b. Copies of all reports required by the permit for at least three years from the date the report was prepared;
c. Records of all data, including reports and documents, used to complete the application for the permit for at least three years from the date the application was filed;
d. A copy of the current permit;
e. A copy of any required record drawings; and
f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules.

[62-620.350]

VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule.

Improvement Action	Completion Date
1. The permittee shall identify and submit the location of background sampling point SWB-1 within 30 days of permit issuance. The sampling point location shall be approved of by the Department's Southeast District Office. The point shall be upstream (north) of outfalls I-012 and I-016.	30 days from permit issuance.

[62-620.320(6)]

2. The following improvement actions shall be completed according to the following schedule. The Storm water Pollution Prevention Plan (SWPPP) shall be prepared and implemented in accordance with Part VII of this permit.

Improvement Action	Completion Date
1. Develop and implement SWPPP	18 months from permit issuance.
2. Complete Plan Summary	2 years from permit issuance.
3. Progress/Update Report	3 years, and then annual thereafter.

[62-620.320(6)]

3. If the permittee wishes to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C. *[62-620.335(1) and (2)]*

4. The permittee shall submit a copy of the Manatee Protection Plan, including any amendments, with the permit renewal application to each of the following agencies no later than one-hundred and eighty days (180) prior to the expiration date of this permit:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Florida Fish and Wildlife Conservation Commission
Bureau of Protected Species Management
620 South Meridian Street
OES-BPS
Tallahassee, Florida 32399-1600

And

US Fish and Wildlife Service
Jacksonville Field Office
7915 Baymeadows Way, Suite 200
Jacksonville, Florida 32256-7517

5. No later than two months after the issuance date of this permit, the permittee shall submit to the Department representative pump curves for each pump associated with Units 1, 2, 3, and 4 that shows the pump performance curve, the system head curve, and the intersection of the two curves.

6. Within six months of the effective date of this permit, the permittee shall schedule a meeting with the Department to discuss the contents of the aquatic organism return plan in accordance with Condition I.B.15 and shall submit the plan to the Department within 12 months of the effective date of this permit. The plan shall be implemented within 24 months subsequent to approval by the Department.

VII. STORMWATER POLLUTION PREVENTION PLAN (SWPPP)

1. General Requirements

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Storm Water Management Industrial Activities Guidance Manual, EPA/833-R92-002 and other EPA documents relating to Best Management Practice guidance.

a. Definitions
   (1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.
   (2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.
   (3) Non-conventional pollutants are those which are not defined as conventional or toxic.
   (4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.
   (5) "Significant Materials" is defined as raw materials; fuels; materials such as solvents and detergents; hazardous substances designated under Section 101(14) of CERCLA; and any chemical the facility is required to report pursuant to EPCRA, Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge.
   (6) "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.
   (7) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.
   (8) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.

(9) "SWPPP" means a Storm Water Pollution Prevention Plan incorporating the requirements of 40 CFR § 125, Subpart K, plus pollution prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.

(10) The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

2. Storm Water Pollution Prevention Plan

The permittee shall develop and implement a SWPPP for the facility, which is the source of wastewater and storm water discharges, covered by this permit. The plan shall be directed toward reducing those pollutants of concern which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities.

a. Signatory Authority & Management Responsibilities

The SWPPP shall be signed by permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The SWPPP shall be reviewed by plant environmental/engineering staff and plant manager. Where required by Chapter 471-(P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of the SWPPP shall be signed and sealed by the professional(s) who prepared them.

A copy of the plan shall be retained at the facility and shall be made available to the permit issuing authority upon request.

The SWPPP shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP program. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the SWPPP.

b. SWPPP Requirements

(1) A topographic map extending one-quarter mile beyond the property boundaries of the facility, showing: the facility, surface water bodies, wells (including injection wells), seepage pits, infiltration ponds, and the discharge points where the facility's storm water discharges to a municipal storm drain system or other water body. The requirements of this paragraph may be included on the site map if appropriate.

(2) A site map showing:
- (a) The storm water conveyance and discharge structures;
- (b) An outline of the storm water drainage areas for each storm water discharge point;
- (c) Paved areas and buildings;
- (d) Areas used for outdoor manufacturing, storage, or disposal of significant materials, including activities that generate significant quantities of dust or particulates;
- (e) Location of existing or future storm water structural control measures/practices (dikes, coverings, detention facilities, etc.);
- (f) Surface water locations and/or municipal storm drain locations;
- (g) Areas of existing and potential soil erosion;
- (h) Vehicle service areas; and
- (i) Material loading, unloading, and access areas.

(3) A narrative description of the following:
- (a) The nature of the industrial activities conducted at the site, including a description of significant materials that are treated, stored or disposed of in a manner to allow exposure to storm water;
- (b) Materials, equipment, and vehicle management practices employed to minimize contact of significant materials with storm water discharges;
- (c) Existing or future structural and non-structural control measures/practices to reduce pollutants in storm water discharges;
- (d) Industrial storm water discharge treatment facilities;

(e) Methods of onsite storage and disposal of significant materials;
(f) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;
(g) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;
(h) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and
(i) The description of a waste minimization assessment performed in accordance with the conditions outlined in condition c below, results of the assessment, and a schedule for implementation of specific waste reduction practices.

(4) A list of the types of pollutants that have a reasonable potential to be present in storm water discharges in significant quantities.

(5) An estimate of the size of the facility in acres or square feet, and the percent of the facility that has impervious areas such as pavement or buildings.

(6) A summary of existing sampling data describing pollutants in storm water discharges.

c. Waste Minimization Assessment

The permittee is encouraged but not required to conduct a waste minimization assessment (WMA) for this facility to determine actions that could be taken to reduce waste loading and chemical losses to all wastewater and/or storm water streams as described in Part VII.D.2 of this permit.

If the permittee elects to develop and implement a WMA, information on plan components can be obtained forms the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8589
(850) 245-8669 – Fax

d. Pollution Prevention Committee:

A pollution prevention committee within the plant organization shall be appointed. These members shall be responsible for developing the SWPPP and assisting the plant manager in its implementation, maintenance, and revision.

e. Employee Training

(1) The permittee shall describe the storm water employee training program for the facility. The description shall include the topics to be covered, such as spill response, good housekeeping and material management practices, and shall identify periodic dates (e.g., every 6 months during the months of July and January) for such training. The permittee shall provide employee training for all employees and contractors that work in areas where industrial materials or activities are exposed to storm water, and for employees that are responsible for implementing activities identified in the SWPPP (*e.g.*, inspectors, maintenance people). The employee training shall inform facility personnel and contractors of the components and goals of the facility SWPPP.

(2) Each employee and contractor that works in an areas where industrial materials or activities are exposed to storm water, and each employee that is responsible for implementing activities identified in the SWPPP shall undergo training at least once a year. Training records shall include trainee's name, signature, date of training and topics covered. Records shall be retained on-site for a minimum of three years.

f. Plan Development & Implementation

(1) The SWPPP shall be developed and implemented 18 months after the effective date of this permit, unless any later dates are specified in this permit. Any portion of the SWPPP which is ongoing at the time of development or implementation shall be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time shall be identified in the plan, including a schedule for its implementation.

(2) The personnel named in the SWPPP shall perform and document a quarterly visual observation of a storm water discharge associated with industrial activity from each outfall. The visual observation shall be made during daylight hours. If no storm event resulted in runoff during daylight hours from the facility during a monitoring quarter, the permittee is excused from the visual observation requirement for that quarter, provided the permittee documents in their records that no runoff occurred. The permittee shall sign and certify the documentation.

(3) The personnel named in the SWPPP shall conduct visual observations on samples collected as soon as practical, but not to exceed 1 hour of when the runoff begins discharging from the facility. All samples must be collected from a storm event discharge that is greater than 0.1 inch in magnitude and that occurs at least 72 hours from the previously measurable (greater than 0.1 inch rainfall) storm event. The observation shall document: color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution.

(4) The permittee shall maintain visual observation reports onsite with the SWPPP for a minimum of three years. The report must include the observation date and time, inspection personnel, nature of the discharge (i.e., runoff), visual quality of the storm water discharge (including observations of color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution), and probable sources of any observed storm water contamination.

(5) At least once a year the personnel named in the SWPPP shall verify that the description of potential pollutant sources required under this permit is accurate; the site map as required in the SWPPP has been updated or otherwise modified to reflect current conditions; and the controls to reduce pollutants in storm water discharges associated with industrial activity identified in the SWPPP are being implemented and are adequate.

g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the SWPPP shall be developed and maintained at the facility and made available to the permit issuing authority upon request. The summary should include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction practices being employed at the facility. The results of waste minimization assessment studies already completed as well as any scheduled or ongoing WMA studies shall be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the permit issuing authority upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices shall be included.

(3) A timetable for the various plan requirements follows:

Timetable for SWPPP Requirements:

REQUIREMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Complete SWPPP	18 months
Complete Plan Summary	2 years
Progress/Update Reports	3 years, and then annually thereafter

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the SWPPP is determined insufficient, the permittee will be notified that the SWPPP does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

The permittee shall modify the SWPPP whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.

The permittee may incorporate applicable portions of plans prepared for other purposes. Plans or portions of plans incorporated into a SWPPP become enforceable requirements of this permit.

VIII. OTHER SPECIFIC CONDITIONS

A. Specific Conditions Applicable to All Permits

1. Where required by Chapter 471 or Chapter 492, F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a professional engineer or a professional geologist, as appropriate. *[62-620.310(4)]*

2. The permittee shall provide verbal notice to the Department's Southeast District Office as soon as practical after discovery of a sinkhole or other karst feature within an area for the management or application of wastewater, or wastewater sludges. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department's Southeast District Office in a written report within 7 days of the sinkhole discovery. *[62-620.320(6)]*

B. Specific Conditions Related to Construction

This section is not applicable to this facility.

C. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

   a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
      (1) One hundred micrograms per liter,
      (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2, 4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol; and one milligram per liter for antimony, or
      (3) Five times the maximum concentration value reported for that pollutant in the permit application; or

   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
      (1) Five hundred micrograms per liter,
      (2) One milligram per liter for antimony, or
      (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

   [62-620.625(1)]

D. Reopener Clauses

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, EPA established Total Maximum Daily Loads (TMDLs), or other information show a need for a different limitation or monitoring requirement.

3. The Department or EPA may develop a TMDL during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

4. The permit shall be reopened for revision as appropriate to address new information that was not available at the time of this permit issuance or to comply with requirements of new regulations, standards, or judicial decisions relating to CWA 316(b).

E. Duty to Reapply

1. The Permittee is not authorized to discharge to waters of the State after the expiration date of this permit, unless:

   a. the Permittee has applied for renewal of this permit at least 180 days before the expiration date (January 22, 2015) using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.; or

   b. the Permittee has made complete the application for renewal of this permit before the permit expiration date.

   [62-620.335(1)-(4), F.A.C.]

2. When publishing Notice of Draft and Notice of Intent in accordance with Rules 62-110.106 and 62-620.550, F.A.C., the permittee shall publish the notice at its expense in a newspaper of general circulation in the county or counties in which the activity is to take place either

   a. Within thirty days after the permittee has received a notice; or
   b. Within thirty days after final agency action.

   Failure to publish a notice is a violation of this permit.

IX. GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1)]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or

conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2)]*

3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3)]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4)]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5)]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6)]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7)]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8)]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;
   b. Have access to and copy any records that shall be kept under the conditions of this permit;
   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and
   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9)]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, F.S., or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10)]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or

terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11)]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12)]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13)]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14)]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15)]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16)]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

    a. A description of the anticipated noncompliance;
    b. The period of the anticipated noncompliance, including dates and times; and
    c. Steps being taken to prevent future occurrence of the noncompliance.

    [62-620.610(17)]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10), or as specified elsewhere in the permit.

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

    d. Except as specifically provided in Rule 62-160.300, F.A.C., any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health Environmental Laboratory Certification Program (DOH ELCP). Such certification shall be for the matrix, test method and analyte(s)

being measured to comply with this permit. For domestic wastewater facilities, testing for parameters listed in Rule 62-160.300(4), F.A.C., shall be conducted under the direction of a certified operator.

e. Field activities including on-site tests and sample collection shall follow the applicable standard operating procedures described in DEP-SOP-001/01 adopted by reference in Chapter 62-160, F.A.C.

f. Alternate field procedures and laboratory methods may be used where they have been approved in accordance with Rules 62-160.220, and 62-160.330, F.A.C.

[62-620.610(18)]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19)]*

20. The permittee shall report to the Department's Tallahassee any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

a. The following shall be included as information which must be reported within 24 hours under this condition:
   (1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
   (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
   (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
   (4) Any unauthorized discharge to surface or ground waters.

b. Oral reports as required by this subsection shall be provided as follows:
   (1) For unauthorized releases or spills of treated or untreated wastewater reported pursuant to subparagraph (a)4. that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:
      (a) Name, address, and telephone number of person reporting;
      (b) Name, address, and telephone number of permittee or responsible person for the discharge;
      (c) Date and time of the discharge and status of discharge (ongoing or ceased);
      (d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
      (e) Estimated amount of the discharge;
      (f) Location or address of the discharge;
      (g) Source and cause of the discharge;
      (h) Whether the discharge was contained on-site, and cleanup actions taken to date;
      (i) Description of area affected by the discharge, including name of water body affected, if any; and
      (j) Other persons or agencies contacted.
   (2) Oral reports, not otherwise required to be provided pursuant to subparagraph b.1 above, shall be provided to the Department's Tallahassee within 24 hours from the time the permittee becomes aware of the circumstances.

c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Tallahassee shall waive the written report.

[62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Permit Conditions IX. 17, 18 or 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Permit Condition IX.20 of this permit. *[62-620.610(21)]*

22. Bypass Provisions.

    a. "Bypass" means the intentional diversion of waste streams from any portion of a treatment works.

    b. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
       (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
       (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
       (3) The permittee submitted notices as required under Permit Condition IX. 22. b. of this permit.

    c. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Permit Condition IX. 20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

    d. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Permit Condition IX. 22. a. 1 through 3 of this permit.

    e. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Permit Condition IX. 22. a. through c. of this permit.

    [62-620.610(22)]

23. Upset Provisions.

    a. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based effluent limitations because of factors beyond the reasonable control of the permittee.
       (1) An upset does not include noncompliance caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, careless or improper operation.
       (2) An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of upset provisions of Rule 62-620.610, F.A.C., are met.

    b. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
       (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
       (2) The permitted facility was at the time being properly operated;
       (3) The permittee submitted notice of the upset as required in Permit Condition IX.5. of this permit; and
       (4) The permittee complied with any remedial measures required under Permit Condition IX. 5. of this permit.

    c. In any enforcement proceeding, the burden of proof for establishing the occurrence of an upset rests with the permittee.

    d. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.

    [62-620.610(23)]

PERMITTEE:	Florida Power and Light	PERMIT NUMBER:	FL0001538 (Major)
FACILITY:	Port Everglades Power Plant	EXPIRATION DATE:	July 21, 2015

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENTOF
ENVIRONMENTAL PROTECTION

Janet G. Llewellyn
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8336

Attachment(s):
Discharge Monitoring Report
Monitor Well Completion Report

2nd AMENDMENT TO THE FACT SHEET AT THE TIME OF PROPOSED PERMIT ISSUANCE

DATE: July 14, 2010

PERMIT NUMBER: FL0001538

PERMITTEE: Florida Power & Light Company
Port Everglades Plant

I. Comments by the Permittee Requesting Changes to the Proposed Permit

The Permittee requested the following changes to the Proposed Permit and Fact Sheet in an email correspondence to the Department dated February 10, 2010 (received via regular mail February 11, 2010). Department comments are ordered to the corresponding comments provided by the permittee. These revisions do not change any effluent limitations or discharge requirements. All items addressed below are considered minor revisions to the permit.

On January 19, 2010 the petitioner, Florida Power & Light Company, was granted an extension of time by the Department's Office of General Counsel to provide comments on the Notice of Intent up to February 10, 2010.

Permit:

1. DEP Comment 14, Amendment to the Fact Sheet, permit condition I.B.7, page 10 of the proposed permit. The previous comment included in the Amendment to the Fact Sheet issued with the Notice of Intent (Mailed December 16, 2009) intended to state, "The permittee shall maintain the current intake through-screen velocity such that the existing maximum velocity is not exceeded." The clarification was added to the permit as condition I.D.20. Through-screen velocity parameter removed from table I.B.7.

2. Page 2, Reuse or Disposal, Outfall D-01B1. The permittee requested that stormwater outfall D-01B1 be considered an internal outfall rather than a surface water outfall. This outfall is upstream of the POD, and not considered Waters of the State as detailed in the fact sheet. The Department concurs with the request to change the designation from D-01B1 to I-01B1. Additionally, the following changes were also made to the permit: permit conditions I.A.12-I.A.16 moved to section I.B, Internal Outfalls, as conditions I.B.16-I.B.20; outfall designation D-01B1 in permit condition I.B.16(formerly I.A.12) changed to I-01B1; permit condition I.A.12 referenced in permit condition I.B.17(formerly I.A.13) changed to I.B.16; conditions I.A.15 and I.A.16 referenced in "Notes" section of permit condition I.B.16 (formerly I.A.12) were changed to I.B.19, and I.B.20, respectively; and references to outfall D-01B1 changed to I-01B1 in permit conditions I.D.19 (formerly I.D.18) and IV.6.

3. Page 14, Condition I.D.14 (formerly I.D.13). The permittee requested a change to the sodium metabisulfate RO feed water concentration from "1 mg or less" to "3 mg or less". The Department's Toxicity Coordinator reviewed and concurred with the requested change.

4. Page 19, Condition VI.2. The permittee requested a change in the timeline to "develop and implement SWPPP" from 6 months from permit issuance to two years to be consistent with permit conditions VII.2.g.(1) and VII.2.g.(3). The Department agreed to 18 months for this timeline. To provide clarification the Department changed the timetable in permit condition VII.2.g.(3), revising "Complete SWPPP" to 18 months from two years, and adding "Complete Plan Summary" with a time limit of 2 years. Permit condition VI.2 was changed to include the revised schedule contained in condition VII.2.g.(3).

5. Page 20 (previously page 19), Condition VI.5. The permittee requested the condition be eliminated or changed to allow the submission of representative pump curves for the facility's circulating water pumps in lieu of conducting testing to provide data. The Department revised the condition to allow for representative curves to be submitted.

6. Page 22, Condition VII.2.f.(1). The permittee requested a change in the timeline to "develop and implement SWPPP" from 6 months from permit issuance to two years to be consistent with comment 4 above. The Department agreed to 18

months for this timeline. To provide clarification the Department changed the timetable in permit condition VII.2.g.(3), revising "Complete SWPPP" to 18 months from two years, and adding "Complete Plan Summary" with a time limit of 2 years. Permit condition VI.2 was changed to include the revised schedule contained in condition VII.2.g.(3).

The Permittee requested the following changes to the Proposed Permit and Fact Sheet in an email correspondence to the Department dated June 22, 2010. Department comments are ordered to the corresponding comments provided by the permittee. These revisions do not change any effluent limitations or discharge requirements.

7. Page 1. Address typographical error corrected.

8. Page 1, Reuse or Disposal, Surface Water Discharge D-001. The permittee requested to change the average daily flow from 1228 MGD to 1295 MGD, however, 1295 MGD is the permitted maximum daily flow. The maximum flow was included in the narrative description.

9. Page 2, Reuse or Disposal, Internal Outfalls I-111 and I-112. The Department agreed to clarify and revise flow rates for both internal outfalls from 115 MGD to 230 MGD. 115 MGD is the maximum flow rate for a single pump, however, each unit employs dual pumps therefore the change to 230 MGD is warranted.

10. Page 2, Reuse or Disposal, Internal Outfalls I-113 and I-114. The Department agreed to clarify and revise flow rates for both internal outfalls from 198 MGD to 396 MGD. 198 MGD is the maximum flow rate for a single pump, however, each unit employs dual pumps therefore the change to 396 MGD is warranted.

11. Page 3, Condition I.A.1. Note reference for Nickel corrected from I.A.6 to I.A.5.

12. Page 7. Number reference "12" removed.

13. See Item 1 above.

14. See Item 3 above.

15. Page 14-15, Condition I.D.15 (formerly I.D.14). Permittee requested language be removed in reference to cooling ponds. The final paragraph was revised to provide clarification.

16. Page 17, Condition III.10. Permittee's request to change the compliance well limit for fluoride from 4.0 mg/l to 5.0 mg/l is denied. The limit of 5.0 mg/l is the Class III Marine surface water criteria not applicable to groundwater discharges. The limit of 4.0 mg/l is in accordance with the MCL contained in Rule 62-550, F.A.C.

17. See Items 4 and 6 above.

18. Page 20, Condition VI.5. The Department acknowledges receipt of representative pump curves as required by condition VI.5 in an email dated June 16, 2010. See Item 5 above.

II. **Other Changes by the Department**

1. Page 12-13, Condition I.D.3. The Department updated standard language within the condition.

2. Page 17, Condition III.10. The compliance well limit for arsenic was updated from 0.05 mg/L to 0.010 mg/L in accordance with the MCL contained in Rules 62-550, 62-550.310(1)(c), and Table 1, F.A.C.

Fact Sheet:

Corresponding changes to permit conditions referenced within the Fact Sheet resulting from changes to the permit enumerated above are noted.

III. **Comments by USEPA Region IV Requesting Changes to the Proposed Permit and Fact Sheet**

The EPA provided comment on Amendment to the Fact Sheet comment 4, in regards to changing the outfall designation D-019, Intake Screen Washwater, to an internal outfall designation "I-019" in an email dated December 31, 2009. The intake canal was previously determined not to be Waters of the State. Copies of documentation in the administrative record supporting the request were forwarded to the EPA. The EPA agreed that the basis for change was valid and not considered back-sliding in an email response dated January 21, 2010.

IV. Other Comments

No comments were received from the public or from other governmental agencies.

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118
Ft Lauderdale, Florida 33316

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd
Fort Lauderdale, FL 33316

COUNTY: Broward
OFFICE: Southeast District

PERMIT NUMBER: FL0001538-007-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-001
MONITORING GROUP DESCRIPTION: POD-Combined OTCW discharge to state waters
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Oxidants, Total Residual[1]	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-5	Permit Requirement					0.01 (Mo.Avg.)	0.01 (Day Max.)	mg/L		Bi-weekly; every 2 weeks	Grab
Temperature (F), Water[2]	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-5	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	Deg F		Bi-weekly; every 2 weeks	Instantaneous

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[1] See permit condition I.B.10.
[2] See permit condition I.A.5.

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 37 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118
Ft Lauderdale, Florida 33316

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd
Fort Lauderdale, FL 33316

COUNTY: Broward

OFFICE: Southeast District

PERMIT NUMBER: FL0001538-007-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-001
MONITORING GROUP DESCRIPTION: POD-Combined OTCW discharge to state waters
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT: Toxicity
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
7-DAY CHRONIC STATRE[1] Mysidopsis bahia(Routine)	Sample Measurement										
PARM Code TRP3E P Mon. Site No. EFF-5	Permit Requirement				100 (Min.)			percent		Quarterly	24-hr FPC
7-DAY CHRONIC STATRE[1] Mysidopsis bahia(Additional)	Sample Measurement										
PARM Code TRP3E Q Mon. Site No. EFF-5	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE[1] Mysidopsis bahia(Additional)	Sample Measurement										
PARM Code TRP3E R Mon. Site No. EFF-5	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE[1] Menidia beryllina(Routine)	Sample Measurement										
PARM Code TRP6B P Mon. Site No. EFF-5	Permit Requirement				100 (Min.)			percent		Quarterly	24-hr FPC
7-DAY CHRONIC STATRE[1] Menidia beryllina(Additional)	Sample Measurement										
PARM Code TRP6B Q Mon. Site No. EFF-5	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE[1] Menidia beryllina(Additional)	Sample Measurement										
PARM Code TRP6B R Mon. Site No. EFF-5	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit

*IF A THIRD ADDITIONAL TEST IS REQUIRED, ENTER THE RESULT ON A SEPARATE TOXICITY DMR, AND CHANGE THE PARM CODE FROM "Q" TO "S"
**ENTER NODI=C IN THE RESULTS COLUMN IF NO DISCHARGE OCCURRED DURING THIS REPORTING PERIOD.
ENTER NODI=9 IN THE RESULTS COLUMN FOR EACH TEST THAT IS NOT REQUIRED.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

[1] See permit condition I.A.4.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 38 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118, Ft Lauderdale, Florida 33316

PERMIT NUMBER: FL0001538-007-IW1S

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd, Fort Lauderdale, FL 33316

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-001
MONITORING GROUP DESCRIPTION: POD-Combined OTCW discharge to state waters
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐

REPORT: Semi-annually
PROGRAM: Industrial

COUNTY: Broward
OFFICE: Southeast District

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Aluminum, Total Recoverable	Sample Measurement										
PARM Code 01104 1	Permit Requirement					1.5 (Mo.Avg.)	1.5 (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Mon. Site No. EFF-5											
Arsenic, Total Recoverable	Sample Measurement										
PARM Code 00978 1	Permit Requirement					36 (Mo.Avg.)	36 (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Mon. Site No. EFF-5											
Cadmium, Total Recoverable	Sample Measurement										
PARM Code 01113 1	Permit Requirement					9.3 (Mo.Avg.)	9.3 (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Mon. Site No. EFF-5											
Copper, Total Recoverable[4] (Effluent – first analysis)	Sample Measurement										
PARM Code 01119 1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Mon. Site No. EFF-5											
Copper, Total Recoverable (Intake – first analysis)	Sample Measurement										
PARM Code 01119 G	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	24-hour FPC
Mon. Site No. SWB-1											
Copper, Total Recoverable (Calculated limit)	Sample Measurement										
PARM Code 01119 P	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Calculated
Mon. Site No. EFF-5											
Copper, Total Recoverable (Effluent minus calculated limit)	Sample Measurement										
PARM Code 01119 Q	Permit Requirement						0.0 (Day.Max.)	ug/L		Semi-Annually; twice per year	Calculated
Mon. Site No. EFF-5											

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

[4] See permit condition I.A.6.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 39 of 70

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL - Port Everglades Power Plant MONITORING GROUP NUMBER: D-001 PERMIT NUMBER: FL0001538-007-IW1S

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Oxygen, Dissolved (DO)[5] (effluent)	Sample Measurement										
PARM Code 00300 1 Mon. Site No. EFF-5	Permit Requirement				Report (Day.Min.)	Report (Mo.Avg.)		mg/L		Semi-Annually; twice per year	Grab
Oxygen, Dissolved (DO) (background)	Sample Measurement										
PARM Code 00300 S Mon. Site No. SWB-1	Permit Requirement				Report (Day.Min.)			mg/L		Semi-Annually; twice per year	Grab
Oxygen, Dissolved (DO) (calculated limit)*	Sample Measurement										
PARM Code 00300 P Mon. Site No. EFF-5	Permit Requirement				Report (Day.Min.)			mg/L		Semi-Annually; twice per year	Grab
Oxygen, Dissolved (DO) (effluent minus calculated limit)	Sample Measurement										
PARM Code 00300 Q Mon. Site No. EFF-5	Permit Requirement				0.00 (Day.Min.)			mg/L		Semi-Annually; twice per year	Grab
Fluoride, Dissolved (as F)	Sample Measurement										
PARM Code 00950 1 Mon. Site No. EFF-5	Permit Requirement					5.0 (Mo.Avg.)	5.0 (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 1 Mon. Site No. EFF-5	Permit Requirement					0.3 (Mo.Avg.)	0.3 (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Lead, Total Recoverable	Sample Measurement										
PARM Code 01114 1 Mon. Site No. EFF-5	Permit Requirement					5.6 (Mo.Avg.)	5.6 (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab

*Calculated limit: Enter the intake D.O. concentration unless the intake D.O. is greater than the applicable Water Quality Criteria, in which case enter the WQC.

[5] See permit condition I.A.7.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 40 of 70

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL - Port Everglades Power Plant

MONITORING GROUP NUMBER: D-001

PERMIT NUMBER: FL0001538-007-IW1S

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Mercury, Total Recoverable	Sample Measurement										
PARM Code 71901 1 Mon. Site No. EFF-5	Permit Requirement					0.025 (Mo.Avg.)	0.025 (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Nickel, Total Recoverable* (Effluent – first analysis)	Sample Measurement										
PARM Code 01074 1 Mon. Site No. EFF-5	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Nickel, Total Recoverable (Intake – first analysis)	Sample Measurement										
PARM Code 01074 G Mon. Site No. SWB-1	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Nickel, Total Recoverable (Calculated limit)	Sample Measurement										
PARM Code 01074 P Mon. Site No. EFF-5	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Nickel, Total Recoverable (Effluent minus calculated limit)	Sample Measurement										
PARM Code 01074 Q Mon. Site No. EFF-5	Permit Requirement						0.0 (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Selenium, Total Recoverable	Sample Measurement										
PARM Code 00981 1 Mon. Site No. EFF-5	Permit Requirement					71 (Mo.Avg.)	71 (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 1 Mon. Site No. EFF-5	Permit Requirement					86 (Mo.Avg.)	86 (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab

* See permit condition I.A.6.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 41 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118
Ft Lauderdale, Florida 33316

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd
Fort Lauderdale, FL 33316

COUNTY: Broward

OFFICE: Southeast District

PERMIT NUMBER: FL0001538-007-JW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-00B3
MONITORING GROUP DESCRIPTION: stormwater from diked petroleum storage or handling areas
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-12	Permit Requirement	Report (Day Ave.)	Report (Day Max.)	MGD						Weekly	Calculated
Petrol Hydrocarbons,Total Recoverable	Sample Measurement										
PARM Code 45501 1 Mon. Site No. EFF-9	Permit Requirement					5.0 (Day Avg.)	5.0 (Day Max.)	mg/L		Monthly	Grab
Turbidity (effluent)[7]	Sample Measurement										
PARM Code 00070 1 Mon. Site No. EFF-9	Permit Requirement						Report (Max.)	NTU		Monthly	Grab
Turbidity (background)	Sample Measurement										
PARM Code 00070 5 Mon. Site No. SWB-1	Permit Requirement						Report (Max.)	NTU		Monthly	Grab
Turbidity (calculated limit)	Sample Measurement										
PARM Code 00070 P Mon. Site No. EFF-9	Permit Requirement						Report (Max.)	NTU		Monthly	Calculated
Turbidity (effluent minus calculated limit)	Sample Measurement										
PARM Code 00070 Q Mon. Site No. EFF-9	Permit Requirement						0.0 (Max.)	NTU		Monthly	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[7] See permit condition I.A.11.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 42 of 70

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL - Port Everglades Power Plant

MONITORING GROUP NUMBER: D-00B3

PERMIT NUMBER: FL0001538-007-IW1S

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 1 Mon. Site No. EFF-9	Permit Requirement					30.0 (Day Avg.)	100.0 (Day Max.)	mg/L		Monthly	Grab
pH[8] (effluent)	Sample Measurement										
PARM Code 00400 1 Mon. Site No. EFF-9	Permit Requirement				Report (Day Min.)		Report (Day Max.)	s.u.		Monthly	Grab
pH (background)	Sample Measurement										
PARM Code 00400 S Mon. Site No. SWB-1	Permit Requirement				Report (Day Min.)		Report (Day Max.)	s.u.		1/Month	Grab
pH (calculated limit)	Sample Measurement										
PARM Code 00400 P Mon. Site No. EFF-9	Permit Requirement				Report (Day Min.)		Report (Day Max.)	s.u.		1/Month	Grab
pH (effluent minus calculated limit)	Sample Measurement										
PARM Code 00400 Q Mon. Site No. EFF-9	Permit Requirement				0.00 (Min.)		0.00 (Max.)	s.u.		1/Month	Grab

[8] See permit condition I.A.12.

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 43 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	FPL - Port Everglades	PERMIT NUMBER:	FL0001538-007-IW1S		
MAILING ADDRESS:	P.O. Box 13118 Ft Lauderdale, Florida 33316	LIMIT: CLASS SIZE:	Final MA	REPORT: PROGRAM:	Monthly Industrial
FACILITY:	FPL - Port Everglades Power Plant	MONITORING GROUP NUMBER:	I-01B1		
LOCATION:	8100 Eisenhower Blvd Fort Lauderdale, FL 33316	MONITORING GROUP DESCRIPTION: RE-SUBMITTED DMR: ☐ NO DISCHARGE FROM SITE: ☐	Equipment area stormwater system discharge to discharge canal		
COUNTY:	Broward	MONITORING PERIOD From:	_____ To: _____		
OFFICE:	Southeast District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow[9]	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-11	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Per discharge	Calculated
Oil and Grease[9]	Sample Measurement										
PARM Code 00556 1 Mon. Site No. EFF-8	Permit Requirement					15.0 (Mo.Avg.)	20.0 (Day.Max.)	mg/L		Per discharge	Grab
Solids, Total Suspended[9]	Sample Measurement										
PARM Code 00530 1 Mon. Site No. EFF-8	Permit Requirement					30.0 (Mo.Avg.)	100.0 (Day.Max.)	mg/L		Per discharge	Grab
Hydrazine[9, 10]	Sample Measurement										
PARM Code 81313 1 Mon. Site No. EFF-8	Permit Requirement						0.3 (Day.Max.)	mg/L		Per discharge	Grab
pH[9]	Sample Measurement										
PARM Code 00400 1 Mon. Site No. EFF-8	Permit Requirement				6.0 (Day.Min.)		9.0 (Day.Max.)	s.u.		Per discharge	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[9] See permit condition I.A.16.
[10] See permit condition I.A.17.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 44 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	FPL - Port Everglades	PERMIT NUMBER:	FL0001538-007-IW1S		
MAILING ADDRESS:	P.O. Box 13118 Ft Lauderdale, Florida 33316	LIMIT: CLASS SIZE:	Final MA	REPORT: PROGRAM:	Semi-annually Industrial
FACILITY: LOCATION:	FPL - Port Everglades Power Plant 8100 Eisenhower Blvd Fort Lauderdale, FL 33316	MONITORING GROUP NUMBER: MONITORING GROUP DESCRIPTION: RE-SUBMITTED DMR: ☐ NO DISCHARGE FROM SITE: ☐	I-012 Water Treatment System		
COUNTY: OFFICE:	Broward Southeast District	MONITORING PERIOD From:	_____ To: _____		

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow[1]	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-9	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Semi-Annually; twice per year	Calculated
Oil and Grease[1]	Sample Measurement										
PARM Code 00556 1 Mon. Site No. EFF-7	Permit Requirement					15.0 (Mo.Avg.)	20.0 (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Suspended[1]	Sample Measurement										
PARM Code 00530 1 Mon. Site No. EFF-7	Permit Requirement					30.0 (Mo.Avg.)	100.0 (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
pH[1]	Sample Measurement										
PARM Code 00400 1 Mon. Site No. EFF-7	Permit Requirement				6.0 (Day.Min.)		9.0 (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[1] See permit condition I.B.3.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 45 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	FPL - Port Everglades	PERMIT NUMBER:	FL0001538-007-IW1S		
MAILING ADDRESS:	P.O. Box 13118 Ft Lauderdale, Florida 33316	LIMIT: CLASS SIZE:	Final MA	REPORT: PROGRAM:	Monthly Industrial
FACILITY:	FPL - Port Everglades Power Plant	MONITORING GROUP NUMBER:	I-016		
LOCATION:	8100 Eisenhower Blvd Fort Lauderdale, FL 33316	MONITORING GROUP DESCRIPTION: RE-SUBMITTED DMR: ☐ NO DISCHARGE FROM SITE: ☐	Boiler Blowdown		
COUNTY:	Broward	MONITORING PERIOD From:	_____ To: _____		
OFFICE:	Southeast District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-10	Permit Requirement		Report (Mo.Avg.)	MGD						Daily; 24 hours	Calculated
Flow, Total Volume	Sample Measurement										
PARM Code 82220 1 Mon. Site No. EFF-6	Permit Requirement		Report (Mo.Avg.)	Mgal						Monthly	Calculated
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 1 Mon. Site No. EFF-6	Permit Requirement					30.0 (Mo.Avg.)	100.0 (Day.Max.)	mg/L		Bi-weekly; every 2 weeks	Grab
Oil and Grease	Sample Measurement										
PARM Code 00556 1 Mon. Site No. EFF-6	Permit Requirement					15.0 (Mo.Avg.)	20.0 (Day.Max.)	mg/L		Bi-weekly; every 2 weeks	Grab
Hydrazine[12]	Sample Measurement										
PARM Code 81313 1 Mon. Site No. EFF-6	Permit Requirement						0.3 (Day.Max.)	mg/L		Per discharge	Grab
pH	Sample Measurement										
PARM Code 00400 1 Mon. Site No. EFF-6	Permit Requirement				6.0 (Day.Min.)		9.0 (Day.Max.)	s.u.		Bi-weekly; every 2 weeks	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[12]See permit condition I.B.6.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 46 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	FPL - Port Everglades	PERMIT NUMBER:	FL0001538-007-IW1S
MAILING ADDRESS:	P.O. Box 13118 Ft Lauderdale, Florida 33316	LIMIT: CLASS SIZE:	*Final* MA
FACILITY:	FPL - Port Everglades Power Plant	MONITORING GROUP NUMBER:	I-111
LOCATION:	8100 Eisenhower Blvd Fort Lauderdale, FL 33316	MONITORING GROUP DESCRIPTION: RE-SUBMITTED DMR: ☐ NO DISCHARGE FROM SITE: ☐	Once-Through Non-Contact Cooling Water for Unit 1
COUNTY:	Broward	MONITORING PERIOD From:	_____ To: _____
OFFICE:	Southeast District		

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-1	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Continuous	Calculated
Temperature (F), Water[13]	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Continuous	Recorder
Temp. Diff. between Intake and Discharge[13]	Sample Measurement										
PARM Code 61576 7 Mon. Site No. INT-1, EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		6/Day	Calculated
Oxidants, Total Residual[14]	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-1	Permit Requirement					0.20 (Mo.Avg.)	0.20 (Day.Max.)	mg/L		Weekly	Grab
Chlorination	Sample Measurement										
PARM Code 50068 7 Mon. Site No. INT-1	Permit Requirement					120 (Mo.Avg.)	120 (Day.Max.)	min/day		Daily; 24 hours	Pump Logs

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and *belief, true, accurate, and complete.* I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[13] See permit condition I.B.9.
[14] See permit condition I.B.10.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 47 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118
Ft Lauderdale, Florida 33316

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd
Fort Lauderdale, FL 33316

COUNTY: Broward
OFFICE: Southeast District

PERMIT NUMBER: FL0001538-007-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-112
MONITORING GROUP DESCRIPTION: Once-Through Non-Contact Cooling Water for Unit 2
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-2	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Continuous	Calculated
Temperature (F), Water[15]	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-2	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Continuous	Recorder
Temp. Diff. between Intake and Discharge[15]	Sample Measurement										
PARM Code 61576 7 Mon. Site No. INT-2, EFF-2	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		6/Day	Calculated
Oxidants, Total Residual[16]	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-2	Permit Requirement					0.20 (Mo.Avg.)	0.20 (Day.Max.)	mg/L		Weekly	Grab
Chlorination	Sample Measurement										
PARM Code 50068 7 Mon. Site No. INT-2	Permit Requirement					120 (Mo.Avg.)	120 (Day.Max.)	min/day		Daily; 24 hours	Pump Logs

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[15] See permit condition I.B.9.
[16] See permit condition I.B.10.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 48 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	FPL - Port Everglades	PERMIT NUMBER:	FL0001538-007-IW1S		
MAILING ADDRESS:	P.O. Box 13118 Ft Lauderdale, Florida 33316	LIMIT: CLASS SIZE:	Final MA	REPORT: PROGRAM:	Monthly Industrial
FACILITY:	FPL - Port Everglades Power Plant	MONITORING GROUP NUMBER:	I-113		
LOCATION:	8100 Eisenhower Blvd Fort Lauderdale, FL 33316	MONITORING GROUP DESCRIPTION: RE-SUBMITTED DMR: ☐ NO DISCHARGE FROM SITE: ☐	Once-Through Non-Contact Cooling Water for Unit 3		
COUNTY:	Broward	MONITORING PERIOD From:	_____ To: _____		
OFFICE:	Southeast District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-3	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Continuous	Calculated
Temperature (F), Water[17]	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-3	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Continuous	Recorder
Temp. Diff. between Intake and Discharge[17]	Sample Measurement										
PARM Code 61576 7 Mon. Site No. INT-3, EFF-3	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		6/Day	Calculated
Oxidants, Total Residual[18]	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-3	Permit Requirement					0.20 (Mo.Avg.)	0.20 (Day.Max.)	mg/L		Weekly	Grab
Chlorination	Sample Measurement										
PARM Code 50068 7 Mon. Site No. INT-3	Permit Requirement					120 (Mo.Avg.)	120 (Day.Max.)	min/day		Daily; 24 hours	Pump Logs

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[17] See permit condition I.B.9.
[18] See permit condition I.B.10.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 49 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	FPL - Port Everglades	PERMIT NUMBER:	FL0001538-007-IW1S		
MAILING ADDRESS:	P.O. Box 13118 Ft Lauderdale, Florida 33316	LIMIT: CLASS SIZE:	Final MA	REPORT: PROGRAM:	Monthly Industrial
FACILITY: LOCATION:	FPL - Port Everglades Power Plant 8100 Eisenhower Blvd Fort Lauderdale, FL 33316	MONITORING GROUP NUMBER: MONITORING GROUP DESCRIPTION: RE-SUBMITTED DMR: ☐ NO DISCHARGE FROM SITE: ☐	I-114 Once-Through Non-Contact Cooling Water for Unit 4		
COUNTY: OFFICE:	Broward Southeast District	MONITORING PERIOD From: _____ To: _____			

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-4	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Continuous	Calculated
Temperature (F), Water[19]	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-4	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Continuous	Recorder
Temp. Diff. between Intake and Discharge[19]	Sample Measurement										
PARM Code 61576 7 Mon. Site No. INT-4, EFF-4	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		6/Day	Calculated
Oxidants, Total Residual[20]	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-4	Permit Requirement					0.20 (Mo.Avg.)	0.20 (Day.Max.)	mg/L		Weekly	Grab
Chlorination	Sample Measurement										
PARM Code 50068 7 Mon. Site No. INT-4	Permit Requirement					120 (Mo.Avg.)	120 (Day.Max.)	min/day		Daily; 24 hours	Pump Logs

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[19] See permit condition I.B.9.
[20] See permit condition I.B.10.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 50 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118
Ft Lauderdale, Florida 33316

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd
Fort Lauderdale, FL 33316

COUNTY: Broward
OFFICE: Southeast District

PERMIT NUMBER: FL0001538-007-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-1D1
MONITORING GROUP DESCRIPTION: Auxiliary Equipment Cooling Water
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-5	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Weekly	Calculated
Temp. Diff. between Sample and Upstrm Deg. F[31]	Sample Measurement										
PARM Code 00018 7 Mon. Site No. INT-5, EFF-1	Permit Requirement					20.0 (Mo.Avg.)	20.0 (Day.Max.)	Deg F		6/Day	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[31] See permit condition I.B.13.

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 51 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118
Ft Lauderdale, Florida 33316

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd
Fort Lauderdale, FL 33316

COUNTY: Broward
OFFICE: Southeast District

PERMIT NUMBER: FL0001538-007-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-1D2
MONITORING GROUP DESCRIPTION: Auxiliary Equipment Cooling Water
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-6	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Weekly	Calculated
Temp. Diff. between Sample and Upstrm Deg. F[22]	Sample Measurement										
PARM Code 00018 7 Mon. Site No. INT-6, EFF-2	Permit Requirement					20.0 (Mo.Avg.)	20.0 (Day.Max.)	Deg F		6/Day	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[22] See permit condition I.B.13.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 52 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	FPL - Port Everglades	PERMIT NUMBER:	FL0001538-007-IW1S		
MAILING ADDRESS:	P.O. Box 13118 Ft Lauderdale, Florida 33316	LIMIT:	*Final*	REPORT:	*Monthly*
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	FPL - Port Everglades Power Plant	MONITORING GROUP NUMBER:	I-1D3		
LOCATION:	8100 Eisenhower Blvd Fort Lauderdale, FL 33316	MONITORING GROUP DESCRIPTION:	Auxiliary Equipment Cooling Water		
		RE-SUBMITTED DMR: ☐			
		NO DISCHARGE FROM SITE: ☐			
COUNTY:	Broward	MONITORING PERIOD From:	_____ To: _____		
OFFICE:	Southeast District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-7	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Weekly	Calculated
Temp. Diff. between Sample and Upstrm Deg. F[23]	Sample Measurement										
PARM Code 00018 7 Mon. Site No. INT-7, EFF-3	Permit Requirement					20.0 (Mo.Avg.)	20.0 (Day.Max.)	Deg F		6/Day	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[23] See permit condition I.B.13.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 53 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118
Ft Lauderdale, Florida 33316

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd
Fort Lauderdale, FL 33316

COUNTY: Broward
OFFICE: Southeast District

PERMIT NUMBER: FL0001538-007-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-1D4
MONITORING GROUP DESCRIPTION: Auxiliary Equipment Cooling Water
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-8	Permit Requirement	Report (Mo.Avg.)	Report (Day Max.)	MGD						Weekly	Calculated
Temp. Diff. between Sample and Upstrm Deg. F[24]	Sample Measurement										
PARM Code 00018 7 Mon. Site No. INT-8, EFF-4	Permit Requirement					20.0 (Mo.Avg.)	20.0 (Day Max.)	Deg F		6/Day	Calculated

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NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[24] See permit condition I.B.13.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 54 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: FPL - Port Everglades
MAILING ADDRESS: P.O. Box 13118
Ft Lauderdale, Florida 33316

FACILITY: FPL - Port Everglades Power Plant
LOCATION: 8100 Eisenhower Blvd
Fort Lauderdale, FL 33316

COUNTY: Broward
OFFICE: Southeast District

PERMIT NUMBER: FL0001538-007-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: R-001
MONITORING GROUP DESCRIPTION: Percolation Basin (Basin B-2)
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-13	Permit Requirement	Report (Mo.Avg.)	Report (Wk.Max.)	MGD						Weekly	Estimated

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NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 55 of 70

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	FPL - Port Everglades	PERMIT NUMBER:	FL0001538-007-IW1S		
MAILING ADDRESS:	P.O. Box 13118 Ft Lauderdale, Florida 33316	LIMIT: CLASS SIZE:	Final MA	REPORT: PROGRAM:	Monthly Industrial
FACILITY:	FPL - Port Everglades Power Plant	MONITORING GROUP NUMBER:	R-002		
LOCATION:	8100 Eisenhower Blvd Fort Lauderdale, FL 33316	MONITORING GROUP DESCRIPTION: RE-SUBMITTED DMR: ☐ NO DISCHARGE FROM SITE: ☐	Stormwater Basin (Basin B-5)		
COUNTY:	Broward	MONITORING PERIOD From:	_____ To: _____		
OFFICE:	Southeast District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-14	Permit Requirement	Report (Mo.Avg.)	Report (Wk.Max.)	MGD						Weekly	Estimated

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 56 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-(W1S
County: Broward

Monitoring Well ID: MWB-01
Well Type: Background
Description: Monitoring Well NOB-1; west of NW corner for B-1

Report: Quarterly
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Water Level Relative to NGVD	82545		Report	Feet	Measured	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
pH	00400		Report	s.u.	In Situ	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				
Iron, Total Recoverable	00980		Report	mg/L	Grab	Quarterly				
Manganese, Total Recoverable	11123		Report	mg/L	Grab	Quarterly				
Sodium, Total Recoverable	00923		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 57 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IW1S
County: Broward

Monitoring Well ID: MWB-01
Well Type: Background
Description: Monitoring Well NOB-1; west of NW corner for B-1

Report: Semi-annually
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Fluoride, Total (as F)	00951		Report	mg/L	Grab	Semi-annually				
Arsenic, Total Recoverable	00978		Report	mg/L	Grab	Semi-annually				
Copper, Total Recoverable	01119		Report	mg/L	Grab	Semi-annually				
Chromium, Total Recoverable	01118		Report	mg/L	Grab	Semi-annually				
Lead, Total Recoverable	01114		Report	mg/L	Grab	Semi-annually				
Nickel, Total Recoverable	01074		Report	mg/L	Grab	Semi-annually				
Silver, Total Recoverable	01079		Report	mg/L	Grab	Semi-annually				
Zinc, Total Recoverable	01094		Report	mg/L	Grab	Semi-annually				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 58 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IW1S
County: Broward

Office: Southeast District

Monitoring Well ID: MWC-01
Well Type: Compliance
Description: Monitoring Well NOB-2A; south of SE corner for B-3

Report: Quarterly
Program: Industrial

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Water Level Relative to NGVD	82545		Report	Feet	Measured	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
pH	00400		Report	s.u.	In Situ	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				
Iron, Total Recoverable	00980		Report	mg/L	Grab	Quarterly				
Manganese, Total Recoverable	11123		Report	mg/L	Grab	Quarterly				
Sodium, Total Recoverable	00923		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 59 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IWIS
County: Broward

Monitoring Well ID: MWC-01
Well Type: Compliance
Description: Monitoring Well NOB-2A; south of SE corner for B-3

Report: Semi-annually
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period: From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Fluoride, Total (as F)	00951		4.0	mg/L	Grab	Semi-annually				
Arsenic, Total Recoverable	00978		0.010	mg/L	Grab	Semi-annually				
Copper, Total Recoverable	01119		Report	mg/L	Grab	Semi-annually				
Chromium, Total Recoverable	01118		0.1	mg/L	Grab	Semi-annually				
Lead, Total Recoverable	01114		0.015	mg/L	Grab	Semi-annually				
Nickel, Total Recoverable	01074		0.1	mg/L	Grab	Semi-annually				
Silver, Total Recoverable	01079		Report	mg/L	Grab	Semi-annually				
Zinc, Total Recoverable	01094		Report	mg/L	Grab	Semi-annually				

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COMMENTS AND EXPLANATION (Reference all attachments here):

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 60 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IW1S
County: Broward

Monitoring Well ID: MWC-02
Well Type: Compliance
Description: Monitoring Well NOB-2B; south of SE corner for B-3

Report: Quarterly
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Water Level Relative to NGVD	82545		Report	Feet	Measured	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
pH	00400		Report	s.u.	In Situ	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				
Iron, Total Recoverable	00980		Report	mg/L	Grab	Quarterly				
Manganese, Total Recoverable	11123		Report	mg/L	Grab	Quarterly				
Sodium, Total Recoverable	00923		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 61 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IW1S
County: Broward

Monitoring Well ID: MWC-02
Well Type: Compliance
Description: Monitoring Well NOB-2B; south of SE corner for B-3

Report: Semi-annually
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period: From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Fluoride, Total (as F)	00951		4.0	mg/L	Grab	Semi-annually				
Arsenic, Total Recoverable	00978		0.010	mg/L	Grab	Semi-annually				
Copper, Total Recoverable	01119		Report	mg/L	Grab	Semi-annually				
Chromium, Total Recoverable	01118		0.1	mg/L	Grab	Semi-annually				
Lead, Total Recoverable	01114		0.015	mg/L	Grab	Semi-annually				
Nickel, Total Recoverable	01074		0.1	mg/L	Grab	Semi-annually				
Silver, Total Recoverable	01079		Report	mg/L	Grab	Semi-annually				
Zinc, Total Recoverable	01094		Report	mg/L	Grab	Semi-annually				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 62 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IW1S
County: Broward

Monitoring Well ID: MWC-03
Well Type: Compliance
Description: Monitoring Well NOB-3A (NOB-3A-R); south of overflow area for B-3

Report: Quarterly
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Water Level Relative to NGVD	82545		Report	Feet	Measured	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
pH	00400		Report	s.u.	In Situ	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				
Iron, Total Recoverable	00980		Report	mg/L	Grab	Quarterly				
Manganese, Total Recoverable	11123		Report	mg/L	Grab	Quarterly				
Sodium, Total Recoverable	00923		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 63 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IW1S
County: Broward

Monitoring Well ID: MWC-03
Well Type: Compliance
Description: Monitoring Well NOB-3A (NOB-3A-R); south of overflow area for B-3

Report: Semi-annually
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Fluoride, Total (as F)	00951		4.0	mg/L	Grab	Semi-annually				
Arsenic, Total Recoverable	00978		0.010	mg/L	Grab	Semi-annually				
Copper, Total Recoverable	01119		Report	mg/L	Grab	Semi-annually				
Chromium, Total Recoverable	01118		0.1	mg/L	Grab	Semi-annually				
Lead, Total Recoverable	01114		0.015	mg/L	Grab	Semi-annually				
Nickel, Total Recoverable	01074		0.1	mg/L	Grab	Semi-annually				
Silver, Total Recoverable	01079		Report	mg/L	Grab	Semi-annually				
Zinc, Total Recoverable	01094		Report	mg/L	Grab	Semi-annually				

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DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 64 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IW1S
County: Broward

Monitoring Well ID: MWC-04
Well Type: Compliance
Description: Monitoring Well NOB-3B1; south of overflow area for B-3

Report: Quarterly
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Water Level Relative to NGVD	82545		Report	Feet	Measured	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
pH	00400		Report	s.u.	In Situ	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				
Iron, Total Recoverable	00980		Report	mg/L	Grab	Quarterly				
Manganese, Total Recoverable	11123		Report	mg/L	Grab	Quarterly				
Sodium, Total Recoverable	00923		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 65 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IW1S
County: Broward

Monitoring Well ID: MWC-04
Well Type: Compliance
Description: Monitoring Well NOB-3B1; south of overflow area for B-3

Report: Semi-annually
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Fluoride, Total (as F)	00951		4.0	mg/L	Grab	Semi-annually				
Arsenic, Total Recoverable	00978		0.010	mg/L	Grab	Semi-annually				
Copper, Total Recoverable	01119		Report	mg/L	Grab	Semi-annually				
Chromium, Total Recoverable	01118		0.1	mg/L	Grab	Semi-annually				
Lead, Total Recoverable	01114		0.015	mg/L	Grab	Semi-annually				
Nickel, Total Recoverable	01074		0.1	mg/L	Grab	Semi-annually				
Silver, Total Recoverable	01079		Report	mg/L	Grab	Semi-annually				
Zinc, Total Recoverable	01094		Report	mg/L	Grab	Semi-annually				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 66 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IWIS
County: Broward

Monitoring Well ID: MWC-05
Well Type: Compliance
Description: Monitoring Well D-1A; south of SE corner for B-1

Report: Quarterly
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (U/F/N)
Water Level Relative to NGVD	82545		Report	Feet	Measured	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
pH	00400		Report	s.u.	In Situ	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				
Iron, Total Recoverable	00980		Report	mg/L	Grab	Quarterly				
Manganese, Total Recoverable	11123		Report	mg/L	Grab	Quarterly				
Sodium, Total Recoverable	00923		Report	mg/L	Grab	Quarterly				

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 67 of 70

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Port Everglades Power Plant
Permit Number: FL0001538-007-IWIS
County: Broward

Monitoring Well ID: MWC-05
Well Type: Compliance
Description: Monitoring Well D-1A; south of SE corner for B-1

Report: Semi-annually
Program: Industrial

Office: Southeast District

Re-submitted DMR: ☐

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Fluoride, Total (as F)	00951		4.0	mg/L	Grab	Semi-annually				
Arsenic, Total Recoverable	00978		0.010	mg/L	Grab	Semi-annually				
Copper, Total Recoverable	01119		Report	mg/L	Grab	Semi-annually				
Chromium, Total Recoverable	01118		0.1	mg/L	Grab	Semi-annually				
Lead, Total Recoverable	01114		0.015	mg/L	Grab	Semi-annually				
Nickel, Total Recoverable	01074		0.1	mg/L	Grab	Semi-annually				
Silver, Total Recoverable	01079		Report	mg/L	Grab	Semi-annually				
Zinc, Total Recoverable	01094		Report	mg/L	Grab	Semi-annually				

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (yy/mm/dd)

COMMENTS AND EXPLANATION (Reference all attachments here):

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 68 of 70

INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT

Read these instructions as well as the SUPPLEMENTAL INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT before completing the DMR. Hard copies and/or electronic copies of the required parts of the DMR were provided with the permit. All required information shall be completed in full and typed or printed in ink. A signed, original DMR shall be mailed to the address printed on the DMR by the 28th of the month following the monitoring period. The DMR shall not be submitted before the end of the monitoring period.

The DMR consists of three parts--A, B, and D--all of which may or may not be applicable to every facility. Facilities may have one or more Part A's for reporting effluent or reclaimed water data. All domestic wastewater facilities will have a Part B for reporting daily sample results. Part D is used for reporting ground water monitoring well data.
When results are not available, the following codes should be used on parts A and D of the DMR and an explanation provided where appropriate. Note: Codes used on Part B for raw data are different.

CODE	DESCRIPTION/INSTRUCTIONS
ANC	Analysis not conducted.
DRY	Dry Well
FLD	Flood disaster.
IFS	Insufficient flow for sampling.
LS	Lost sample.
MNR	Monitoring not required this period.

CODE	DESCRIPTION/INSTRUCTIONS
NOD	No discharge from/to site.
OPS	Operations were shutdown so no sample could be taken.
OTH	Other. Please enter an explanation of why monitoring data were not available.
SEF	Sampling equipment failure.

When reporting analytical results that fall below a laboratory's reported method detection limits or practical quantification limits, the following instructions should be used:

1. Results greater than or equal to the PQL shall be reported as the measured quantity.
2. Results less than the PQL and greater than or equal to the MDL shall be reported as the laboratory's MDL value. These values shall be deemed equal to the MDL when necessary to calculate an average for that parameter and when determining compliance with permit limits.
3. Results less than the MDL shall be reported by entering a less than sign ("<") followed by the laboratory's MDL value, e.g. < 0.001. A value of one-half the MDL or one-half the effluent limit, whichever is lower, shall be used for that sample when necessary to calculate an average for that parameter. Values less than the MDL are considered to demonstrate compliance with an effluent limitation.

PART A -DISCHARGE MONITORING REPORT (DMR)

Part A of the DMR is comprised of one or more sections, each having its own header information. Facility information is preprinted in the header as well as the monitoring group number, whether the limits and monitoring requirements are interim or final, and the required submittal frequency (e.g. monthly, annually, quarterly, etc.). Submit Part A based on the required reporting frequency in the header and the instructions shown in the permit. The following should be completed by the permittee or authorized representative:

No Discharge From Site: Check this box if no discharge occurs and, as a result, there are no data or codes to be entered for all of the parameters on the DMR for the entire monitoring group number; however, if the monitoring group includes other monitoring locations (e.g., influent sampling), the "NOD" code should be used to individually denote those parameters for which there was no discharge.
Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Sample Measurement: Before filling in sample measurements in the table, check to see that the data collected correspond to the limit indicated on the DMR (i.e. interim or final) and that the data correspond to the monitoring group number in the header. Enter the data or calculated results for each parameter on this row in the non-shaded area above the limit. Be sure the result being entered corresponds to the appropriate statistical base code (e.g. annual average, monthly average, single sample maximum, etc.) and units.
No. Ex.: Enter the number of sample measurements during the monitoring period that exceeded the permit limit for each parameter in the non-shaded area. If none, enter zero.
Frequency of Analysis: The shaded areas in this column contain the minimum number of times the measurement is required to be made according to the permit. Enter the actual number of times the measurement was made in the space above the shaded area.
Sample Type: The shaded areas in this column contain the type of sample (e.g. grab, composite, continuous) required by the permit. Enter the actual sample type that was taken in the space above the shaded area.
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comment and Explanation of Any Violations: Use this area to explain any exceedances, any upset or by-pass events, or other items which require explanation. If more space is needed, reference all attachments in this area.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 69 of 70

PART B - DAILY SAMPLE RESULTS

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Daily Monitoring Results: Transfer all analytical data from your facility's laboratory or a contract laboratory's data sheets for all day(s) that samples were collected. Record the data in the units indicated. Table 1 in Chapter 62-160, F.A.C., contains a complete list of all the data qualifier codes that your laboratory may use when reporting analytical results. However, when transferring numerical results onto Part B of the DMR, only the following data qualifier codes should be used and an explanation provided where appropriate.

CODE	DESCRIPTION/INSTRUCTIONS
<	The compound was analyzed for but not detected.
A	Value reported is the mean (average) of two or more determinations.
J	Estimated value, value not accurate.
Q	Sample held beyond the actual holding time.
Y	Laboratory analysis was from an unpreserved or improperly preserved sample.

Add the results to get the Total and divide by the number of days in the month to get the Monthly Average.
Plant Staffing: List the name, certificate number, and class of all state certified operators operating the facility during the monitoring period. Use additional sheets as necessary.

PART D - GROUND WATER MONITORING REPORT

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Date Sample Obtained: Enter the date the sample was taken. Also, check whether or not the well was purged before sampling.
Time Sample Obtained: Enter the time the sample was taken.
Sample Measurement: Record the results of the analysis. If the result was below the minimum detection limit, indicate that.
Detection Limits: Record the detection limits of the analytical methods used.
Analysis Method: Indicate the analytical method used. Record the method number from Chapter 62-160 or Chapter 62-601, F.A.C., or from other sources.
Sampling Equipment Used: Indicate the procedure used to collect the sample (e.g. airlift, bucket/bailer, centrifugal pump, etc.)
Samples Filtered: Indicate whether the sample obtained was filtered by laboratory (L), filtered in field (F), or unfiltered (N).
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comments and Explanation: Use this space to make any comments on or explanations of results that are unexpected. If more space is needed, reference all attachments in this area.

SPECIAL INSTRUCTIONS FOR LIMITED WET WEATHER DISCHARGES

Flow (Limited Wet Weather Discharge): Enter the measured average flow rate during the period of discharge or divide gallons discharged by duration of discharge (converted into days). Record in million gallons per day (MGD).
Flow (Upstream): Enter the average flow rate in the receiving stream upstream from the point of discharge for the period of discharge. The average flow rate can be calculated based on two measurements; one made at the start and one made at the end of the discharge period. Measurements are to be made at the upstream gauging station described in the permit.
Actual Stream Dilution Ratio: To calculate the Actual Stream Dilution Ratio, divide the average upstream flow rate by the average discharge flow rate. Enter the Actual Stream Dilution Ratio accurate to the nearest 0.1.
No. of Days the SDF > Stream Dilution Ratio: For each day of discharge, compare the minimum Stream Dilution Factor (SDF) from the permit to the calculated Stream Dilution Ratio. On Part B of the DMR, enter an asterisk (*) if the SDF is greater than the Stream Dilution Ratio on any day of discharge. On Part A of the DMR, add up the days with an "*" and record the total number of days the Stream Dilution Factor was greater than the Stream Dilution Ratio.
$CBOD_5$: Enter the average $CBOD_5$ of the reclaimed water discharged during the period shown in duration of discharge.
TKN: Enter the average TKN of the reclaimed water discharged during the period shown in duration of discharge.
Actual Rainfall: Enter the actual rainfall for each day on Part B. Enter the actual cumulative rainfall to date for this calendar year and the actual total monthly rainfall on Part A. The cumulative rainfall to date for this calendar year is the total amount of rain, in inches, that has been recorded since January 1 of the current year through the month for which this DMR contains data.
Rainfall During Average Rainfall Year: On Part A, enter the total monthly rainfall during the average rainfall year and the cumulative rainfall for the average rainfall year. The cumulative rainfall for the average rainfall year is the amount of rain, in inches, which fell during the average rainfall year from January through the month for which this DMR contains data.
No. of Days LWWD Activated During Calendar Year: Enter the cumulative number of days that the limited wet weather discharge was activated since January 1 of the current year.
Reason for Discharge: Attach to the DMR a brief explanation of the factors contributing to the need to activate the limited wet weather discharge.

Docket No. 120007-EI
FDEP IWWF Permit No. FL0001538 for PPE
Exhibit RRL-2, Page 70 of 70

FLORIDA POWER & LIGHT COMPANY

PPE MANATEE PROTECTION PLAN ("MPP")

RRL-3
DOCKET NO. 120007-EI
EXHIBIT _____
PAGES 1 OF 11

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI **EXHIBIT** 5
PARTY Florida Power & Light Co.
DESCRIPTION R.R. BaBauve (RRL-3); PPE Manatee Protection Plan (MPP)

NPDES/IWN

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the matter of:
Approval of FPL Port Everglades Plant
Manatee Protection Plan

DEP Permit No. FL0001538
Broward County

Mr. Ron Hix
Florida Power & Light Company
P.O. Box 088801
North Palm Beach, FL 33408-08801

NOTICE OF AGENCY ACTION

The Department of Environmental Protection hereby gives notice of its approval of the enclosed Manatee Protection Plan for the FPL Port Everglades Plant, completed July 12, 1999 pursuant to Specific Condition 20 of Permit Number FL0001538.

A person whose substantial interests are affected by the Department action may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes.

The petition must contain the information set forth below and must be filed (received) in the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within twenty-one days of receipt of this notice of intent. Petitions filed by any other person must be filed within twenty-one days of publication of the public notice or within twenty-one days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the discretion of the presiding officer upon the filing of a motion in compliance with rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:
(a) The name, address, and telephone number of each petitioner; the Department case identification number and the county in which the subject matter or activity is located;
(b) A statement of how and when each petitioner received notice of the Department action;
(c) A statement of how each petitioner's substantial interests are affected by the Department action;

(d) A statement of the material facts disputed by the petitioner, if any;
(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department action;
(f) A statement of which rules or statutes the petitioner contends require reversal or modification of the Department action; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department final action may be different from the position taken by it in this order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation under section 120.573 of the Florida Statutes is not available for this proceeding

This action is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above. Upon the timely filing of a petition this order will not be effective until further order of the Department.

Any party to the order has the right to seek judicial review of the order under section 120.68 of the Florida Statutes, by the filing of a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000; and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when the final order is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mimi Drew
Director
Division of Water Resource Management

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 487-1855

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF AGENCY ACTION and all copies were mailed before the close of business on 08-18-99 to the listed persons.

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

G. Shields 08-18-99

(Clerk) (Date)

Copies furnished to:

Tim Powell, DEP Southeast District
Kipp Frohlich, FWC Tallahassee
Jennifer Fitzwater, DEP Office of General Counsel
Scott Cowan, Chairman, Board of Broward County Commissioners
Jim Valade, U.S. Fish and Wildlife Service
Save the Manatee Club

Florida Fish and Wildlife Conservation Commission

ames L. "Jamie" Adams, Jr. Bushnell | Barbara C. Barsh Jacksonville | Patrick E. Geraghty Ft. Myers | Quinton L. Hedgepeth, DDS Miami | H.A. "Herky" Huffman Deltona
Thomas B. Kilber Lakeland | David K. Meehan St Petersburg | Julie K. Morris Sarasota | Tony Moss Miami | Edwin P. Roberts, DC Pensacola | John D. Rood Jacksonville

LLAN L. EGBERT, Ph.D., Executive Director
ICTOR J. HELLER, Assistant Executive Director

620 South Meridian Street
Tallahassee, FL 32399-1600
www.state.fl.us/gfc
(850)487-3796
TDD (850)488-9542

July 13, 1999

Vince Seibold
Florida Department of Environmental Protection
Industrial Wastewater Section
Mail Station 3545
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
JUL 19 1999
Industrial Wastewater Section

Dear Vince;

I have attached the Manatee Protection Plan dated July 12, 1999 for Florida Power & Light's (FPL) Port Everglades' facility. The Bureau of Protected Species Management has reviewed the attached plan and with this letter acknowledges our acceptance of this plan as that required by permit condition 20, of the FPL-Port Everglades NPDES permit. I have provided the following chronological list recounting the submittal of Florida Power & Light-Port Everglades draft Manatee Protection Plans and our corresponding responses.

May 11, 1998	The Bureau of Protected Species Management receives a draft Manatee Protection Plan from Florida Power & Light's Port Everglades facility
July 1, 1998	The Bureau of Protected Species Management provides comments and recommended modifications to FPL- Port Everglades.
August 19, 1998	FPL provides the Bureau of Protected Species Management a second draft of the FPL-Port Everglades Manatee Protection Plan
September 16, 1998	FPL resubmits the second draft of the FPL-Port Everglades Manatee Protection Plan
November 12, 1998	The Bureau of Protected Species Management provides recommendations to the second draft of the FPL-Port Everglades Manatee Protection Plan
December 17, 1998	FPL submits a final draft of the Port Everglades Manatee Protection Plan to the Bureau of Protected Species Management.

February 23, 1999	The Bureau provides DEP's Industrial Wastewater Section with a copy of the final draft of the Manatee Management Plan for FPL-Port Everglades and asks what further information is required to complete the process.
March 3, 1999	DEP's Industrial Wastewater Section provides a protocol for the approval of Manatee Protection Plans.
May 28, 1999	The Bureau of Protected Species Management provides the U S. Fish and Wildlife Service (USFWS) with a copy of the final draft of the FPL-Port Everglades Manatee Protection Plan for review and comment
June 1, 1999	The USFWS provides several recommended modifications to the FPL-Port Everglades final draft plan.
June 3, 1999	The Bureau of Protected Species receives a carbon copy of the USFWS letter to the Department's Industrial Wastewater Section providing their concurrence to the attached Manatee Protection Plan for the FPL-Port Everglades facility.
July 12, 1999	The Bureau of Protected Species Management receives concurrence from FPL-Port Everglades on the attached Manatee Protection Plan dated July 12, 1999

If you have any questions or need further information, please call me at suncom 292-4330.

Sincerely,

OFFICE OF ENVIRONMENTAL SERVICES

R Kipp Frohlich
Biological Administrator
Bureau of Protected Species Management

\rrm
NPDES.099\WW-FPL-PtEverglades-ltr.713 doc
ENV 7-2
Attachment

cc: R Hix
J Valade

United States Department of the Interior

FISH AND WILDLIFE SERVICE
6620 Southpoint Drive South
Suite 310
Jacksonville, Florida 32216-0912

JUN 01 1999

RECEIVED
JUN 3 1999
BUREAU OF PROTECTED SPECIES
MARINE RESOURCES DIVISION

Vince Seibold
Florida Department of Environmental Protection
Division of Water Facilities
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Seibold:

The Fish and Wildlife Service (Service) has reviewed manatee protection plans for the following facilities:

Florida Power and Light's Fort Myers Plant
(State Industrial Wastewater Permit Number FL0001490)

Florida Power and Light's Ft. Lauderdale Plant
(State Industrial Wastewater Permit Number FL0001503)

Florida Power and Light's Port Everglades Plant
(State Industrial Wastewater Permit Number FL0001538)

The measures incorporated in these plans are consistent with the intent of the Florida Manatee Recovery Plan, which seeks to maintain safe and reliable warm water refuges for wintering manatees. The Service believes that the measures included in these plans will give manatees adequate protection during the periods specified in the permits at the respective power plants.

Thank you for the opportunity to review these plans.

Sincerely,

James A. Valade
Assistant Recovery Manatee Coordinator

cc: FDEP/BPSM - Ron Mezich
FWS Vero Beach Field Office - Jay Slack

Florida Power & Light - Port Everglades
Manatee Protection Plan

Purpose:

The purpose of the Port Everglades Plant Manatee Protection Plan is to set forth Florida Power & Light Company's (FPL) procedures to comply with Specific Condition 20 of the facility's State Industrial Wastewater Permit Number FL0001538 that was issued on November 17, 1997. This Specific Condition reads, in part:

20. The permittee, in so far as required to comply with Tasks 25 and 251 of the U.S. Fish and Wildlife Service (USFWS) "Florida Manatee Recovery Plan," shall develop a plan and procedures addressing potential manatee impacts. ...All plans, if required, shall include an implementation schedule and address, at a minimum:

    (a) Plans to minimize disruption to warm-water outflows during the winter and response procedures in case of disruptions.

    (b) Strategy to maintain discharge temperatures that will sustain manatees during cold events.

    (c) Plan to monitor ambient and discharge temperatures.

    (d) Precautions to minimize hazards to manatees at intake and outfall areas.

    (e) Timely communication to manatee recovery program personnel of any long term changes in the availability of warm water.

Compliance with Specific Condition 20:

1. This Manatee Protection Plan will be in effect during the term of the permit. In order for the plant's warm water discharge to provide a safe, warm water refuge for the manatees and to comply with Specific Condition 20, FPL will take the following actions:

    a) In the case of an unplanned shutdown or plant failure that will affect the warm water refuge from November 15 through March 31, when the ambient water temperature is below 61°F, the Florida Wildlife Conservation Commission (FWCC) and USFWS will be notified no later than four (4) hours after the event has occurred. The following agency representatives shall be notified in the above referenced event or if any distressed manatees are observed at any time:

    FWCC - Florida Marine Research Institute - Marine Mammal Pathobiology Lab: ~~(813)~~ 727-893-2904
    USFWS - Jacksonville Field Office: (904) 232-2580

    The FWCC, Bureau of Protected Species Management (BPSM) shall be provided a schedule of any anticipated in-water work within the discharge canal or work that will affect the warm water refuge during the period of November 15 through March 31 each year. No routine in-water maintenance work shall occur in the discharge canal from November 15 through March 31, unless it is considered essential by FPL and approved by BPSM prior to the start of work. If emergency in-water work is needed, the BPSM will be notified and consulted no later than two weeks following the commencement of the activity. All vessels used in the operation or associated with the activity shall be operated pursuant to the attached standard manatee construction conditions

b) From November 15 through March 31 each year, to coincide with the time of greatest manatee abundance, if the ambient water temperature falls below 61°F, the FPL Port Everglades plant shall endeavor to operate in a manner that maintains the water temperature in an adequate portion of the discharge canal at or above 68°F, until such time as the ambient water temperature reaches 61°F, unless otherwise authorized by BPSM and the USFWS, or unless safety or reliability of the plant would be compromised.

c) The FPL Port Everglades power plant will provide personnel from the BPSM, USFWS, Florida Marine Research Institute, USGS-Sirenia Project, or a designee of these agencies, access to FPL Port Everglades power plant property to conduct manatee research and monitoring activities which may include, placing, maintaining and downloading data from temperature data loggers. (These temperature data loggers will be used to collect air and water temperature data in an ongoing research effort to better understand manatee behavior patterns in response to artificial warm water refugia and environmental variables. The temperature data loggers will be placed in the discharge canal and at ambient water and air locations). Access would be limited to normal business hours (8:00am - 5:00pm) unless arrangements are made in advance with the FPL Port Everglades power plant.

d) Intake Area: The plant environmental specialist, or an alternate designee, will survey the intake canal, at a minimum, three times per week (year round) to determine the presence or absence of manatees. In addition, all plant personnel will be instructed to report to the environmental specialist (or designee) immediately upon the sighting of a manatee in the intake canal. If a manatee is sighted in the intake canal, the following action plan will be implemented:

1. Sightings will be logged. FPL will maintain a log of manatee sightings in the intake canal, which will include the following information.

   - Approximate date entered canal
   - Approximate date departed canal
   - Maximum days in canal
   - Description of animal(s)
   - Other appropriate comments

2. The intake canal will be observed daily to determine the continued presence or absence of the manatee(s).

3. If a manatee is present for seven consecutive days, or if any distressed (i.e.; injured, orphaned) manatees are observed at any time, the FWCC and USFWS should be notified at the aforementioned numbers. See condition "1.a)".

Discharge Area: No special surveys will be required for the discharge canal.

e) Should FPL decide to retire these units, notice will be provided to FWCC and USFWS as soon as practical after a definite decision is made or, if possible, at least five years prior to the date of retirement.

f) To assist in documenting long-term use patterns of this facility, FPL should conduct periodic aerial surveys of manatees at the Port Everglades facility. The continuation of the ongoing statewide aerial survey that FPL has funded in the past years meets these criteria.

g) The FPL Port Everglades Power Plant will provide phone numbers for weekday and weekend notification of appropriate plant personnel for the purpose of allowing FWCC or USFWS to coordinate manatee rescue operations as necessary.

2) FPL actions, pursuant to this plan, that will be conducted on a one-time basis unless there are significant physical or operational changes to the FPL Port Everglades power plant.

a) Provide a site map of the facility as a part of the plan that includes the following information;

1. The location of the intake pipes and outfall pipes.
2. Proximate streams, rivers, bays, etc.
3. The location of the condenser inlet and outlet temperature monitoring stations.
4. The location of any fuel barge docking facilities in relation to the discharge canal.
5. The delineation of the no-entry boundary at the discharge canal.

b) In order to evaluate and determine what portions of the thermal discharge will provide a sufficient warm water refuge for manatees under potential cold stress water conditions; the FPL Port Everglades power plant will, within two (2) years of the effective date of this plan, provide a profile of the thermal gradient (either actual or calculated) of the discharge canal waters, as well as its gross bathymetry, at the mean rate of discharge when the ambient water temperature reaches a seasonal low.

FLORIDA POWER & LIGHT – PORT EVERGLADES PLANT
MANATEE PROTECTION PLAN

1a) STANDARD MANATEE CONSTRUCTION CONDITIONS FOR ARTIFICIAL WARM WATER REFUGIA DURING THE PERIOD OF NOVEMBER 15 THROUGH MARCH 31.

The permittee shall comply with the following manatee protection conditions:

a. The permittee shall instruct all personnel associated with in-water work within the discharge canal and/or the warm water refuge of the potential presence of manatees and the need to avoid collisions with manatees. All vessels used in the operation or in association with the in-water work shall have an observer on board responsible for identifying the presence and location of manatee(s).

b. The permittee shall advise all construction personnel that there are civil and criminal penalties for harming, harassing, or killing manatees which are protected under the Marine Mammal Protection Act of 1972, The Endangered Species Act of 1973, and the Florida Manatee Sanctuary Act.

c. All vessels associated with in-water work associated with the discharge canal and/or warm water refuge shall operate at "no wake/idle" speeds at all times while in the manatee warm water refuge area. All vessels will follow routes of deep water whenever possible.

d. If manatee(s) are seen within the discharge canal and/or warm water refuge area all appropriate precautions shall be implemented to ensure protection of the manatee(s). These precautions shall include the immediate shutdown of equipment if necessary. Activities will not resume until the manatee(s) has departed to a safe distance on its own volition.

e. Any collision with and/or injury to a manatee shall be reported immediately to the Florida Fish & Wildlife Conservation Commission at (1-800-342-5367). Collision and/or injury should also be reported to the U.S. Fish and Wildlife Service in Jacksonville (1-904-232-2580)

FLORIDA POWER & LIGHT COMPANY

U.S. FISH AND WILDLIFE SERVICE ("FWS") LETTER TO FPL REGARDING MANATEE PROTECTION AT PPE

RRL-4
DOCKET NO. 120007-EI
EXHIBIT _____
PAGES 1 OF 4

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	**EXHIBIT**	6
PARTY	Florida Power & Light Co.		
DESCRIPTION	R.R. BaBauve (RRL-4); U.S. Fish and Wildlife letters to FPL in re manatee protection at PPE.		

United States Department of the Interior

FISH AND WILDLIFE SERVICE
South Florida Ecological Services Office
1339 20th Street
Vero Beach, Florida 32960

December 16, 2011

Randall LaBauve
Florida Power and Light Company
700 Universe Blvd.
Juno Beach, Florida 33408

Service Federal Activity Code: 04EF2000-2012-CPA-0061
Service Consultation Code: 04EF2000-2012- TA-0047
Date Received: November 1, 2011
Applicant: Florida Power & Light Co.
County: Broward

Dear Mr. LaBauve:

The U.S. Fish and Wildlife Service (Service) appreciates Florida Power and Light Company's (FPL) efforts to coordinate with our agency regarding the company's plans to repower the Port Everglades Power Plant in Fort Lauderdale, Broward County, Florida. The following represents our understanding of your request for technical assistance.

The Service met with FPL representatives on September 13, 2011, to discuss FPL's proposed repowering efforts for Port Everglades which include the demolition of the existing facility in 2013 and construction of the new power plant (scheduled to be operational in 2016). The power plant's deconstruction and reconstruction phases will eliminate the plant's warm water discharge, which is used by manatees during the winter months (November 15-March 31). Typically, manatees seek warm water sites when temperatures drop below 68°F. When manatees experience prolonged exposure to water temperatures below 68°F, they often develop a condition called cold stress syndrome, which can be fatal.

During the meeting, FPL provided information about the extent of warm water habitat currently used by manatees in the plant's discharge canal, including the area of warm water, discharge temperatures and discharge volumes. According to FPL's Manatee Protection Plan for Port Everglades, if the ambient water temperature decreases to 61°F, the power plant is required to operate the plant in a manner that maintains the water temperature in the discharge canal at or above 68°F. FPL presented temperature data from November 15 to March 31 for the past 13 years (1998-2011) in which the ambient water temperature never decreased to 61°F.

According to the Service's 2007 status review of the Florida manatee, FPL's Port Everglades Power Plant is one of two protected primary warm water refuge sites for manatees in Broward County. The other warm water site is FPL's Lauderdale Power Plant located inland approximately 4.7 miles west southwest of the Port Everglades plant.

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Since 1977-78, annual aerial surveys have documented manatee use of the Port Everglades plant's discharge canal as a source of warm water during the winter months with numbers of individuals ranging from 35 in 1983-84 to 454 in 2008-09. For the same time period, documented manatee use of the Lauderdale plant's discharge site ranged from 0 manatees in 1992-93 to 463 in 2009-10. During the 2010-11 survey, 391 and 335 manatees were recorded at the Port Everglades and Lauderdale plants, respectively.

Cold stress mortality is low in Broward County. Since 1977-78, 21 manatees have died in Broward County as a result of cold stress; however, most of these deaths were more recent with 13 manatees dying from February 2009 to December 2010, with 2010 having the coldest water temperatures on record in parts of south Florida. Collier County and Palm Beach County had water temperatures at or below 45°F.

According to your staff, FPL proposes to protect manatees during the winter months while the Port Everglades plant is offline by providing warm water from a temporary heat source. FPL intends to install and operate a heater that will pump warm water into the plant's discharge canal should the need arise. The availability of warm water during the winter months minimizes the potential for cold stress effects on manatees at this location.

In coordination with the Florida Fish and Wildlife Conservation Commission (FWC), the Service is willing to consider an alternative operational approach for the Port Everglades site than the one used at FPL's Cape Canaveral and Riviera Beach sites, two other plants currently being repowered. This alternative would require a temporary heater, but the size and operation of the heating system could be different at this site because of its southern location and proximity to the warm water site at FPL's Lauderdale plant. To minimize the effects of cold stress on manatees, we recommend the following conditions as the operational trigger to turn on the temporary heater: (1) the ambient water temperature at the Port Everglades site is 65°F or lower and (2) the Lauderdale power plant is not operational. The 65°F trigger is the same temperature threshold for the temporary heaters operating at the Cape Canaveral and Riviera Beach sites.

While the plant is offline and being rebuilt, FPL also agreed to monitor the movement of manatees from the Port Everglades plant site to the Lauderdale plant site during the winter season. Broward County, in accordance with their Manatee Protection Plan, currently conducts aerial surveys of manatees in county waterways during the winter months. The Service has determined that Broward County's aerial survey results are an acceptable substitute to FPL's commitment to monitor manatee movement. If Broward County is unable to perform their aerial surveys for any reason, FPL has agreed to monitor manatees in the county and, particularly, those traveling between the two plant sites from November 15 to March 31.

In addition, the Service would like FPL to consider tagging a number of manatees while the Port Everglades plant is offline to determine where manatees go and to monitor their health status when there is no warm water at the plant's discharge site. The details of this effort should be worked out in coordination with our office and FWC during the state site certification permitting process. All of the actions described above must be acceptable to FWC.

At present, there are no authorizations in place under either the Marine Mammal Protection Act of 1972 or the Endangered Species Act of 1973 for the incidental take of manatees and their critical habitat. Wintering habitat is the most important biological factor limiting manatee populations and is integral to the recovery of the species. Your proposal to provide a temporary heat source when needed while the Port Everglades plant is offline during the repowering process minimizes the potential effect of cold stress to manatees. In addition, manatees have the nearby Lauderdale plant as an alternative warm water site available to them during this period. As such, the Port Everglades repowering process is unlikely to result in the take of manatees as long as FPL's Lauderdale plant is operating normally.

FPL is a valued partner in the conservation and recovery of the manatee and we are confident that you will make every effort to provide for manatees as you move ahead with repowering the Port Everglades plant. We look forward to maintaining the consistent level of coordination and cooperation with you on this important issue.

If you have any questions, please contact Kalani Cairns at 772-469-4240.

Sincerely yours,

Craig Aubrey

for Larry Williams
Field Supervisor
South Florida Ecological Services Office

cc: electronic only
Corps, West Palm Beach, Florida (Leah Oberlin)
FWC, Tallahassee, Florida (Carol Knox, CPS)

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1A THROUGH 42-9A

JANUARY 2011 - DECEMBER 2011
FINAL TRUE-UP

TJK-1
DOCKET NO. 120007-EI
EXHIBIT_____
PAGES 1-70

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 7
PARTY Florida Power & Light Co.
DESCRIPTION T.J. Keith (TJK-1), Appendix I Env. cost)
Final True up 1-12/11, CF 42-1A-9A

Form 42-1A

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up
For the Period January 2011 through December 2011

Line No.			
1	Over/(Under) Recovery for the Current Period (Form 42-2A Page 2 of 2, Line 5)	$9,632,723	
2	Interest Provision (Form 42-2A Page 2 of 2, Line 6)	$52,862	
3	Total		$9,685,585
4	Actual/Estimated Over/(Under) Recovery for the Same Period *	$8,647,633	
5	Interest Provision	61,040	
6	Total		$8,708,673
7	Net True-Up for the period		$976,912

*Approved in FPSC Order No. PSC-11-0553-FOF-EI dated December 7, 2011

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2011 through December 2011

Line No.		January	February	March	April	May	June
1	ECRC Revenues (net of Revenue Taxes)	$13,775,033	$11,515,412	$9,034,033	$10,645,090	$11,348,251	$12,797,516
2	True-up Provision (Order No. PSC-11-0083-FOF-EI)	3,351,777	3,351,777	3,351,777	3,351,777	3,351,777	3,351,777
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	17,126,810	14,867,189	12,385,810	13,996,867	14,700,028	16,149,293
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5A, Line 9)	1,587,230	1,236,474	1,914,752	2,054,131	1,665,532	5,283,874
	b - Capital Investment Projects (Form 42-7A, Line 9)	12,091,790	12,123,969	11,906,334	11,949,389	12,203,667	12,375,493
	c - Total Jurisdictional ECRC Costs	13,679,021	13,360,443	13,821,086	14,003,520	13,869,199	17,659,367
5	Over/(Under) Recovery (Line 3 - Line 4c)	3,447,789	1,506,746	(1,435,276)	(6,653)	830,830	(1,510,075)
6	Interest Provision (Form 42-3A, Line 10)	9,437	9,257	7,713	6,024	4,978	4,060
7	Prior Periods True-Up to be (Collected)/Refunded in 2011	40,221,324	40,326,773	38,491,000	33,711,660	30,359,254	27,843,285
	a - Deferred True-Up from 2010 (Form 42-1A, Line 7)	5,036,425	5,036,425	5,036,425	5,036,425	5,036,425	5,036,425
8	True-Up Collected /(Refunded) (See Line 2)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)
9	End of Period True-Up (Lines 5+6+7+7a+8)	45,363,199	43,527,425	38,748,085	35,395,680	32,879,710	28,021,918
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$45,363,199	$43,527,425	$38,748,085	$35,395,680	$32,879,710	$28,021,918

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2011 through December 2011

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$12,842,140	$13,414,446	$13,736,149	$11,529,675	$9,485,841	$9,576,152	$139,699,738
2	True-up Provision (Order No. PSC-11-0083-FOF-EI)	3,351,777	3,351,777	3,351,777	3,351,777	3,351,777	3,351,777	40,221,324
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	16,193,917	16,766,223	17,087,926	14,881,452	12,837,618	12,927,929	179,921,062
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5A, Line 9)	2,513,327	(2,611,825)	7,268,419	2,166,883	1,902,480	(2,108,540)	22,872,738
	b - Capital Investment Projects (Form 42-7A, Line 9)	12,368,726	12,407,188	12,436,539	12,467,870	12,491,978	12,592,658	147,415,602
	c - Total Jurisdictional ECRC Costs	14,882,053	9,795,364	19,704,958	14,634,753	14,394,458	10,484,118	170,288,340
5	Over/(Under) Recovery (Line 3 - Line 4c)	1,311,864	6,970,859	(2,617,032)	246,698	(1,556,840)	2,443,811	9,632,723
6	Interest Provision (Form 42-3A, Line 10)	3,150	2,664	1,886	1,565	1,432	696	52,862
7	Prior Periods True-Up to be (Collected)/Refunded in 2011	22,985,493	20,948,730	24,570,476	18,603,554	15,500,040	10,592,855	40,221,324
	a - Deferred True-Up from 2010 (Form 42-1A, Line 7)	5,036,425	5,036,425	5,036,425	5,036,425	5,036,425	5,036,425	
8	True-Up Collected /(Refunded) (See Line 2)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(40,221,324)
9	End of Period True-Up (Lines 5+6+7+7a+8)	25,985,156	29,606,902	23,639,979	20,536,466	15,629,280	14,722,011	9,685,585
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$25,985,156	$29,606,902	$23,639,979	$20,536,466	$15,629,280	$14,722,011	$9,685,585

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2011 through December 2011

Interest Provision (in Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$45,257,749	$45,363,199	$43,527,425	$38,748,085	$35,395,680	$32,879,710
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	45,353,762	43,518,168	38,740,372	35,389,656	32,874,732	28,017,859
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$90,611,511	$88,881,367	$82,267,798	$74,137,741	$68,270,412	$60,897,569
4	Average True-Up Amount (Line 3 x 1/2)	$45,305,756	$44,440,684	$41,133,899	$37,068,871	$34,135,206	$30,448,784
5	Interest Rate (First Day of Reporting Month)	0.25000%	0.25000%	0.25000%	0.20000%	0.19000%	0.16000%
6	Interest Rate (First Day of Subsequent Month)	0.25000%	0.25000%	0.20000%	0.19000%	0.16000%	0.16000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.50000%	0.50000%	0.45000%	0.39000%	0.35000%	0.32000%
8	Average Interest Rate (Line 7 x 1/2)	0.25000%	0.25000%	0.22500%	0.19500%	0.17500%	0.16000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.02083%	0.02083%	0.01875%	0.01625%	0.01458%	0.01333%
10	Interest Provision for the Month (Line 4 x Line 9)	$9,437	$9,257	$7,713	$6,024	$4,978	$4,060

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2011 through December 2011

Interest Provision (in Dollars)

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$28,021,918	$25,985,156	$29,606,902	$23,639,979	$20,536,466	$15,629,280	N/A
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	25,982,006	29,604,238	23,638,093	20,534,901	15,627,848	14,721,315	N/A
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$54,003,924	$55,589,393	$53,244,995	$44,174,880	$36,164,314	$30,350,595	N/A
4	Average True-Up Amount (Line 3 x 1/2)	$27,001,962	$27,794,697	$26,622,498	$22,087,440	$18,082,157	$15,175,297	N/A
5	Interest Rate (First Day of Reporting Month)	0.16000%	0.12000%	0.11000%	0.06000%	0.11000%	0.08000%	N/A
6	Interest Rate (First Day of Subsequent Month)	0.12000%	0.11000%	0.06000%	0.11000%	0.08000%	0.03000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.28000%	0.23000%	0.17000%	0.17000%	0.19000%	0.11000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	0.14000%	0.11500%	0.08500%	0.08500%	0.09500%	0.05500%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.01167%	0.00958%	0.00708%	0.00708%	0.00792%	0.00458%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$3,150	$2,664	$1,886	$1,565	$1,432	$696	$52,862

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2011 - December 2011

Variance Report of O&M Activities
(in Dollars)

Line		(1) Actual	(2) Actual Estimated	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
1	Air Operating Permit Fees	$743,295	$1,183,121	($439,826)	-37.2%
3a	Continuous Emission Monitoring Systems	$780,836	$866,057	($85,222)	-9.8%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks	$893,972	$1,666,131	($772,159)	-46.3%
8a	Oil Spill Cleanup/Response Equipment	$203,682	$218,477	($14,795)	-6.8%
13	RCRA Corrective Action	$25,888	$92,127	($66,239)	-71.9%
14	NPDES Permit Fees	$153,148	$124,400	$28,748	23.1%
17a	Disposal of Noncontainerized Liquid Waste	$42,519	$65,000	($22,481)	-34.6%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution	$2,016,006	$2,823,488	($807,482)	-28.6%
19b	Substation Poilutant Discharge Prevention & Removal - Transmission	$1,637,031	$1,513,458	$123,573	8.2%
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($560,232)	($560,232)	$0	0.0%
NA	Amortization of Gains on Sales of Emissions Allowances	($279,502)	($279,501)	($1)	0.0%
22	Pipeline Integrity Management	$111,676	$235,392	($123,716)	-52.6%
23	SPCC-Spill Prevention, Control & Countermeasures	$939,017	$1,069,671	($130,654)	-12.2%
24	Manatee Reburn	$594,569	$602,856	($8,287)	-1.4%
25	Port Everglades ESP	$321,932	$649,118	($327,186)	-50.4%
27	Lowest Quality Water Source	$312,765	$315,621	($2,857)	-0.9%
28	CWA 316(b) Phase II Rule	$133,674	$122,329	$11,345	9.3%
29	SCR Consumables	$425,093	$383,263	$41,830	10.9%
30	HBMP	$45,789	$30,541	$15,249	49.9%
31	CAIR Compliance	$1,782,857	$1,617,761	$165,096	10.2%
33	CAMR Compliance	$1,960,884	$2,335,558	($374,674)	-16.0%
34	St. Lucie Cooling Water System Inspection & Maintenance	$728,120	$671,676	$56,444	8.4%
35	Martin Plant Drinking Water System Compliance	$52,096	$22,174	$29,922	134.9%
37	DeSoto Next Generation Solar Energy Center	$902,831	$970,099	($67,268)	-6.9%
38	Space Coast Next Generation Solar Energy Center	$451,893	$530,047	($78,154)	-14.7%
39	Martin Next Generation Solar Energy Center	$4,741,970	$2,422,554	$2,319,416	95.7%
40	Greenhouse Gas Reduction Program	$48,556	$55,000	($6,444)	-11.7%
41	Manatee Temporary Heating System Project	$1,299,801	$1,339,480	($39,679)	-3.0%
42	Turkey Point Cooling Canal Monitoring Plan	$2,618,300	$2,721,497	($103,197)	-3.8%
43	NESHAP Information Collection Request Project	$25,903	$8,385	$17,518	208.9%
46	St. Lucie Cooling Water Discharge Monitoring Project	$123,675	$240,677	($117,003)	-48.6%
47	NPDES Industrial Waste Water Permits	$19,658	$33,000	($13,342)	-40.4%
2	Total O&M Activities	$23,297,701	$24,089,224	($791,523)	-3.3%
3	Recoverable Costs Allocated to Energy	$ 10,673,102	$ 11,860,944	($1,187,842)	-10.0%
4a	Recoverable Costs Allocated to CP Demand	$ 10,888,709	$ 9,684,908	$1,203,801	12.4%
4b	Recoverable Costs Allocated to GCP Demand	$ 1,735,890	$ 2,543,372	($807,482)	-31.7%

Notes:
Column(1) is the 12-Month Totals on Form 42-5A
Column(2) is the approved actual/estimated amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2011 - December 2011

O&M Activities
(in Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of O&M Activities							
	1 Air Operating Permit Fees	$ 106,665	$ 116,415	$ 106,415	$ 106,415	$ 106,415	$ 91,539	$633,865
	3a Continuous Emission Monitoring Systems	183,180	17,050	14,048	92,001	22,205	30,754	359,238
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks	2,214	402	0	17,459	240,021	364,421	624,516
	8a Oil Spill Cleanup/Response Equipment	2,690	16,917	14,876	12,350	11,448	18,790	77,071
	13 RCRA Corrective Action	0	4,048	0	0	0	6,479	10,527
	14 NPDES Permit Fees	124,400	0	0	0	0	0	124,400
	17a Disposal of Noncontainerized Liquid Waste	0	0	0	0	0	0	0
	18a Substation Pollutant Discharge Prevention & Removal - Distribution	36,700	162,058	132,624	87,810	84,628	184,668	688,488
	19b Substation Pollutant Discharge Prevention & Removal - Transmission	(77,980)	229,128	232,364	106,537	219,803	43,105	752,958
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
	NA Amortization of Gains on Sales of Emissions Allowances	(21,426)	(21,426)	(21,426)	(21,426)	(23,500)	(38,921)	(148,125)
	22 Pipeline Integrity Management	15,417	(32,511)	(4,859)	794	144	13,193	(7,823)
	23 SPCC - Spill Prevention, Control & Countermeasures	67,139	53,624	105,614	69,482	94,930	116,608	507,397
	24 Manatee Rebum	31,753	78,062	130,909	34,388	2,916	12,813	290,841
	25 Pt. Everglades ESP Technology	28,009	20,131	26,957	26,729	10,166	20,542	132,535
	27 Lowest Quality Water Source	26,276	24,130	25,777	26,483	25,128	26,072	153,866
	28 CWA 316(b) Phase II Rule	3,514	5,284	10,745	6,476	6,108	4,201	36,328
	29 SCR Consumables	25,384	29,452	63,490	26,668	30,127	22,826	197,947
	30 HBMP	1,712	1,720	5,088	5,088	1,712	1,720	17,041
	31 CAIR Compliance	119,009	116,133	151,065	131,710	162,859	118,730	799,505
	33 CAMR Compliance	197,212	42,966	197,100	121,199	126,838	180,037	865,151
	34 St. Lucie Cooling Water System Inspection & Maintenance	164,795	14,350	148,697	225,430	94,139	12,265	659,676
	35 Martin Plant Drinking Water System Compliance	0	0	3,696	1,848	1,848	3,695	11,086
	37 DeSoto Next Generation Solar Energy Center	90,487	66,075	70,956	80,084	81,984	107,630	497,215
	38 Space Coast Next Generation Solar Energy Center	43,491	33,597	30,610	41,941	32,054	38,264	219,957
	39 Martin Next Generation Solar Energy Center	84,777	117,122	90,212	478,202	77,766	3,460,674	4,308,754
	40 Greenhouse Gas Reduction Program	0	2,500	1,056		0	0	3,556
	41 Manatee Temporary Heating System Project	281,268	118,324	131,693	124,395	76,149	147,890	879,718
	42 Turkey Point Cooling Canal Monitoring Plan	128,886	89,681	327,657	328,495	253,580	433,198	1,561,497
	43 NESHAP Information Collection Request Project	0	0	2,385	0	0	0	2,385
	46 St. Lucie Cooling Water Discharge Monitoring Project	0	0	0	10,263	5,203	12,297	27,763
	47 NPDES Industrial Waste Water Permits	0	0	0	0	0	0	0
2	Total of O&M Activities	$ 1,618,885	$ 1,258,548	$ 1,951,062	$ 2,094,133	$ 1,697,785	$ 5,386,803	$ 14,007,216
3	Recoverable Costs Allocated to Energy	$ 1,074,836	$ 642,036	$ 1,162,303	$ 989,323	$ 794,114	$ 1,039,719	$ 5,702,330
4a	Recoverable Costs Allocated to CP Demand	$ 530,692	$ 477,798	$ 679,478	$ 1,040,343	$ 842,386	$ 4,185,758	$ 7,756,456
4b	Recoverable Costs Allocated to GCP Demand	$ 13,357	$ 138,715	$ 109,281	$ 64,467	$ 61,285	$ 161,325	$ 548,430
5	Retail Energy Jurisdictional Factor	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	
6a	Retail CP Demand Jurisdictional Factor	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 1,053,630	$ 629,369	$ 1,139,372	$ 969,804	$ 778,447	$ 1,019,207	$ 5,589,829
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 520,243	$ 468,390	$ 666,099	$ 1,019,860	$ 825,800	$ 4,103,343	$ 7,603,735
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 13,357	$ 138,715	$ 109,281	$ 64,467	$ 61,285	$ 161,325	$ 548,430
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 1,587,230	$ 1,236,474	$ 1,914,752	$ 2,054,131	$ 1,665,532	$ 5,283,874	$ 13,741,994

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2011 - December 2011

O&M Activities
(in Dollars)

Line #	Project #	Actual JUL	Actual AUG	Actual SEP	Actual OCT	Actual NOV	Actual DEC	6-Month Sub-Total	12-Month Total	Method of Classification: CP Demand	Method of Classification: GCP Demand	Method of Classification: Energy
1	Description of O&M Activities											
	1 Air Operating Permit Fees	$ 56,537	$ 93,825	$ 124,455	$ (111,369)	$ (72,352)	$ 18,534	$109,430	$743,295			$743,295
	3a Continuous Emission Monitoring Systems	181,498	132,267	5,828	(18,827)	108,975	33,856	421,597	780,836			780,836
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks	(17,423)	38,738	(2,862)	174,437	35,709	40,857	269,457	893,972	893,972		
	8a Oil Spill Cleanup/Response Equipment	430	11,599	12,876	12,099	5,585	84,222	126,811	203,682			203,682
	13 RCRA Corrective Action	0	0	861	0	3,000	11,500	15,361	25,888	25,888		
	14 NPDES Permit Fees	0	302	8,434	0	4,670	15,342	28,748	153,148	153,148		
	17a Disposal of Noncontainerized Liquid Waste	0	21,364	20,218	784	0	153	42,519	42,519			42,519
	19a Substation Pollutant Discharge Prevention & Removal - Distribution	69,245	216,838	213,432	115,914	361,134	350,955	1,327,518	2,016,006		2,016,006	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission	7,638	22,077	200,847	116,815	109,383	427,513	884,073	1,637,031	1,511,106		125,925
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,666)	(46,666)	(46,666)	(46,666)	(46,666)	(46,666)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
	NA Amortization of Gains on Sales of Emissions Allowances	(21,896)	(21,896)	(21,896)	(21,896)	(21,896)	(21,897)	(131,376)	(279,502)			(279,502)
	22 Pipeline Integrity Management	27,011	14,063	18,266	4,119	26,752	29,280	119,499	111,676	111,676		
	23 SPCC - Spill Prevention, Control & Countermeasures	81,292	72,857	63,136	45,279	79,858	89,198	431,620	939,017	939,017		
	24 Manatee Reburn	45,028	29,617	0	181,785	6,920	40,377	303,727	594,569			594,569
	25 Pt. Everglades ESP Technology	41,789	53,493	42,588	27,966	9,870	13,890	189,397	321,932			321,932
	27 Lowest Quality Water Source	26,157	27,035	26,366	26,355	26,093	26,893	158,899	312,765	312,765		
	28 CWA 316(b) Phase II Rule	7,473	66,811	7,904	22,106	(9,965)	3,017	97,346	133,674	133,674		
	29 SCR Consumables	34,827	26,199	24,821	40,237	37,122	63,940	227,146	425,093			425,093
	30 HBMP	1,712	1,720	1,973	4,892	7,199	11,452	28,749	45,789	45,789		
	31 CAIR Compliance	97,040	174,784	124,975	311,506	130,904	144,143	983,352	1,782,857			1,782,857
	33 CAMR Compliance	390,535	58,960	195,204	170,221	158,682	122,131	1,095,733	1,960,884			1,960,884
	34 St. Lucie Cooling Water System Inspection & Maintenance	600	(22,269)	80,000	(5,879)	(2,488)	18,480	68,445	728,120	728,120		
	35 Martin Plant Drinking Water System Compliance	0	1,848	6,838	3,696	3,696	24,935	41,010	52,096	52,096		
	37 DeSoto Next Generation Solar Energy Center	65,751	68,048	65,256	63,514	66,184	74,862	405,616	902,831	902,831		
	38 Space Coast Next Generation Solar Energy Center	32,665	38,215	37,364	34,316	34,408	54,969	231,936	451,893	451,893		
	39 Martin Next Generation Solar Energy Center	1,462,433	(4,370,565)	5,903,279	951,592	626,586	(4,140,110)	433,216	4,741,970	4,741,970		
	40 Greenhouse Gas Reduction Program	0	0	36,500	8,500	0	0	45,000	48,556			48,556
	41 Manatee Temporary Heating System Project	13,851	123,478	38,971	83,476	61,435	98,873	420,083	1,299,801			1,299,801
	42 Turkey Point Cooling Canal Monitoring Plan	25,211	482,919	186,153	7,135	149,426	205,958	1,056,803	2,818,300			2,818,300
	43 NESHAP Information Collection Request Project	0	16,440	0	8,480	598	0	23,518	25,903			25,903
	46 St. Lucie Cooling Water Discharge Monitoring Project	0	0	35,920	0	33,329	26,663	95,912	123,675	123,675		
	47 NPDES Industrial Waste Water Permits	0		0	405	0	19,254	19,658	19,658	19,658		
2	Total of O&M Activities	$ 2,582,919	$ (2,668,121)	$ 7,410,620	$ 2,208,574	$ 1,933,930	$ (2,157,436)	$ 9,290,485	$ 23,297,701	$ 10,888,709	$ 1,735,890	$ 10,673,102
3	Recoverable Costs Allocated to Energy	$ 843,658	$ 1,202,750	$ 804,132	$ 705,273	$ 579,668	$ 835,271	$ 4,970,772	$ 10,673,102			
4a	Recoverable Costs Allocated to CP Demand	$ 1,673,359	$ (4,064,366)	$ 6,418,398	$ 1,410,729	$ 1,018,451	$ (3,320,319)	$ 3,132,253	$ 10,888,709			
4b	Recoverable Costs Allocated to GCP Demand	$ 45,902	$ 193,495	$ 190,089	$ 92,571	$ 337,791	$ 327,612	$ 1,187,460	$ 1,735,890			
5	Retail Energy Jurisdictional Factor	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%					
6a	Retail CP Demand Jurisdictional Factor	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 827,013	$ 1,179,021	$ 788,267	$ 691,359	$ 568,251	$ 818,792	$ 4,872,703	$ 10,462,532			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 1,640,411	$ (3,984,341)	$ 6,290,063	$ 1,382,953	$ 996,436	$ (3,254,943)	$ 3,070,581	$ 10,674,316			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 45,902	$ 193,495	$ 190,089	$ 92,571	$ 337,791	$ 327,612	$ 1,187,460	$ 1,735,890			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 2,513,327	$ (2,611,825)	$ 7,268,419	$ 2,166,883	$ 1,902,480	$ (2,108,540)	$ 9,130,744	$ 22,872,738			

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
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Variance Report of Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		(1) Actual	(2) Actual Estimated	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
2	Low NOx Burner Technology	$329,955	$329,955	$0	0.0%
3b	Continuous Emission Monitoring Systems	$676,243	$676,243	$0	0.0%
4b	Clean Closure Equivalency	$2,092	$2,092	$0	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,037,356	$1,037,943	($588)	-0.1%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,610	$1,610	($0)	0.0%
8b	Oil Spill Cleanup/Response Equipment	$108,301	$125,621	($17,320)	-13.8%
10	Relocate Storm Water Runoff	$8,422	$8,422	$0	0.0%
NA	SO2 Allowances-Negative Return on Investment	($185,051)	($185,051)	($0)	0.0%
12	Scherer Discharge Pipeline	$57,309	$57,309	$0	0.0%
20	Wastewater Discharge Elimination & Reuse	$131,895	$134,676	($2,781)	-2.1%
21	St. Lucie Turtle Net	$106,449	$106,246	$204	0.2%
22	Pipeline Integrity Management	$0	$5,991	($5,991)	-100.0%
23	SPCC-Spill Prevention, Control & Countermeasures	$2,070,253	$2,052,033	$18,220	0.9%
24	Manatee Reburn	$3,371,252	$3,371,252	$0	0.0%
25	Pt. Everglades ESP Technology	$8,230,136	$8,230,136	$0	0.0%
26	UST Replacement/Removal	$32,717	$32,723	($5)	0.0%
31	CAIR Compliance	$45,265,319	$45,557,242	($291,923)	-0.6%
33	CAMR Compliance	$12,678,863	$12,693,336	($14,474)	-0.1%
35	Martin Plant Drinking Water System Compliance	$32,435	$27,781	$4,654	16.8%
36	Low-Level Radioactive Waste Storage	$436,411	$465,504	($29,093)	-6.2%
37	DeSoto Next Generation Solar Energy Center	$17,896,024	$17,909,444	($13,420)	-0.1%
38	Space Coast Next Generation Solar Energy Center	$8,484,552	$8,484,479	$73	0.0%
39	Martin Next Generation Solar Energy Center	$48,350,476	$48,388,726	($38,250)	-0.1%
41	Manatee Temporary Heating System Project	$842,513	$853,668	($11,155)	-1.3%
42	Turkey Point Cooling Canal Monitoring Plan	$407,704	$407,704	$0	0.0%
44	Martin Plant Barley Barber Swamp Iron Mitigation Project	$4,130	$8,002	($3,872)	-48.4%
2	Total Investment Projects-Recoverable Costs	$ 150,377,367	$ 150,783,087	$ (405,720)	-0.3%
3	Recoverable Costs Allocated to Energy	$ 23,034,128	$ 23,065,040	$ (30,913)	-0.1%
4	Recoverable Costs Allocated to Demand	$ 127,343,239	$ 127,718,046	$ (374,807)	-0.3%

Notes:
Column(1) is the 12-Month Totals on Form 42-7A
Column(2) is the approved actual/estimated amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2011 - December 2011

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of Investment Projects (A)							
	2 Low NOx Burner Technology	$28,367	$28,208	$28,050	$27,892	$27,734	$ 27,575	$ 167,826
	3b Continuous Emission Monitoring Systems	57,428	57,232	57,037	56,842	56,646	56,451	341,636
	4b Clean Closure Equivalency	177	177	176	176	175	175	1,056
	5b Maintenance of Stationary Above Ground Fuel Storage Tanks	87,520	87,332	87,144	86,956	86,768	86,543	522,262
	7 Relocate Turbine Lube Oil Underground Piping to Above Ground	137	136	136	135	135	134	814
	8b Oil Spill Cleanup/Response Equipment	8,839	8,809	8,773	8,740	8,666	8,612	52,439
	10 Relocate Storm Water Runoff	710	708	707	705	704	703	4,236
	NA SO2 Allowances-Negative Return on Investment	(16,354)	(16,182)	(16,011)	(15,839)	(15,681)	(15,522)	(95,589)
	12 Scherer Discharge Pipeline	4,848	4,835	4,821	4,808	4,795	4,782	28,890
	20 Wastewater Discharge Elimination & Reuse	12,778	12,774	12,761	11,626	10,485	10,464	70,887
	21 St. Lucie Turtle Net	8,877	8,873	8,869	8,864	8,860	8,856	53,199
	22 Pipeline Integrity Management	0	0	0	0	0	0	0
	23 SPCC - Spill Prevention, Control & Countermeasures	170,158	170,803	171,329	171,247	171,233	172,976	1,027,746
	24 Manatee Reburn	283,965	283,415	282,864	282,314	281,763	281,213	1,695,534
	25 Pt. Everglades ESP Technology	692,526	691,311	690,097	688,882	687,667	686,452	4,136,935
	26 UST Removal / Replacement	4,485	4,478	4,472	4,136	3,802	3,801	25,174
	31 CAIR Compliance	3,568,582	3,599,441	3,381,151	3,433,307	3,674,055	3,828,900	21,485,437
	33 CAMR Compliance	1,060,802	1,059,868	1,060,084	1,060,457	1,061,018	1,058,774	6,361,002
	35 Martin Plant Drinking Water System Compliance	2,224	2,221	2,218	2,214	2,211	2,927	14,015
	36 Low-Level Radioactive Waste Storage	0	0	0	0	25,951	53,508	79,459
	37 DeSoto Next Generation Solar Energy Center	1,503,930	1,502,257	1,500,408	1,498,720	1,497,265	1,495,084	8,997,663
	38 Space Coast Next Generation Solar Energy Center	715,904	714,232	712,740	711,299	709,628	707,933	4,271,737
	39 Martin Next Generation Solar Energy Center	4,037,210	4,042,747	4,043,397	4,042,278	4,041,408	4,040,339	24,247,380
	41 Manatee Temporary Heating System Project	66,968	68,714	69,749	69,787	69,741	69,670	414,630
	42 Turkey Point Cooling Canal Monitoring Plan	34,650	35,166	34,577	33,921	33,824	33,781	205,920
	44 Barley Barber Swamp Iron Mitigation	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 12,334,731	$ 12,367,555	$ 12,145,549	$ 12,189,468	$ 12,448,854	$ 12,624,132	$ 74,110,289
3	Recoverable Costs Allocated to Energy	$ 1,914,301	$ 1,915,028	$ 1,896,153	$ 1,897,734	$ 1,915,878	$ 1,927,551	$ 11,466,646
4	Recoverable Costs Allocated to Demand	$ 10,420,430	$ 10,452,527	$ 10,249,395	$ 10,291,734	$ 10,532,977	$ 10,696,581	$ 62,643,643
5	Retail Energy Jurisdictional Factor	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	
6	Retail Demand Jurisdictional Factor	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,876,534	$ 1,877,247	$ 1,858,744	$ 1,860,294	$ 1,878,079	$ 1,889,523	$ 11,240,421
8	Jurisdictional Demand Recoverable Costs (C)	$ 10,215,257	$ 10,246,722	$ 10,047,590	$ 10,089,095	$ 10,325,588	$ 10,485,970	$ 61,410,222
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 12,091,790	$ 12,123,969	$ 11,906,334	$ 11,949,389	$ 12,203,667	$ 12,375,493	$ 72,650,643

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Totals may not add due to rounding.

Florida Power & Light Company
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Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Actual JUL	Actual AUG	Actual SEP	Actual OCT	Actual NOV	Actual DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)										
2	Low NOx Burner Technology	$ 27,417	$ 27,259	$ 27,101	$ 26,942	$ 26,784	$ 26,626	$ 162,129	$ 329,955		$ 329,955
3b	Continuous Emission Monitoring Systems	56,256	56,061	55,865	55,670	55,475	55,280	334,607	676,243		676,243
4b	Clean Closure Equivalency	174	174	173	172	172	171	1,036	2,092	1,931	161
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks	86,319	86,131	85,943	85,755	85,567	85,379	515,094	1,037,356	957,559	79,797
7	Relocate Turbine Lube Oil Underground Piping to Above Ground	134	133	133	132	132	131	796	1,610	1,486	124
8b	Oil Spill Cleanup/Response Equipment	8,520	8,361	9,228	9,339	9,292	11,122	55,862	108,301	99,970	8,331
10	Relocate Storm Water Runoff	701	700	698	697	695	694	4,186	8,422	7,774	648
NA	SO2 Allowances-Negative Return on Investment	(15,348)	(15,173)	(14,998)	(14,823)	(14,648)	(14,472)	(89,463)	(185,051)		(185,051)
12	Scherer Discharge Pipeline	4,769	4,756	4,743	4,730	4,717	4,704	28,420	57,309	52,901	4,408
20	Wastewater Discharge Elimination &Reuse	8,969	10,442	10,428	10,409	10,390	10,370	61,008	131,895	121,750	10,145
21	St. Lucie Turtle Net	8,852	8,848	8,855	8,872	8,899	8,926	53,250	106,449	98,261	8,188
22	Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	174,421	174,106	173,787	173,611	173,445	173,136	1,042,507	2,070,253	1,911,002	159,251
24	Manatee Reburn	280,662	280,112	279,562	279,011	278,461	277,910	1,675,718	3,371,252		3,371,252
25	Pt. Everglades ESP Technology	685,237	684,022	682,808	681,593	680,378	679,163	4,093,202	8,230,136		8,230,136
26	UST Removal / Replacement	2,415	1,030	1,028	1,027	1,023	1,020	7,543	32,717	30,201	2,516
31	CAIR Compliance	3,835,108	3,888,487	3,934,973	3,980,118	4,015,237	4,125,958	23,779,882	45,265,319	41,783,371	3,481,948
33	CAMR Compliance	1,055,897	1,054,867	1,053,754	1,052,502	1,050,947	1,049,893	6,317,860	12,678,863	11,703,565	975,298
35	Martin Plant Drinking Water System Compliance	3,658	3,736	3,798	2,850	2,191	2,188	18,420	32,435	29,940	2,495
36	Low-Level Radioactive Waste Storage	57,029	58,858	59,081	59,524	60,962	61,498	356,952	436,411	402,841	33,570
37	DeSoto Next Generation Solar Energy Center	1,491,577	1,488,040	1,484,421	1,481,060	1,477,130	1,476,132	8,898,361	17,896,024	16,519,407	1,376,617
38	Space Coast Next Generation Solar Energy Center	706,310	704,683	703,057	702,080	699,734	696,951	4,212,815	8,484,552	7,831,894	652,658
39	Martin Next Generation Solar Energy Center	4,034,832	4,027,615	4,018,850	4,010,961	4,006,977	4,003,861	24,103,096	48,350,476	44,631,208	3,719,268
41	Manatee Temporary Heating System Project	69,581	69,521	69,464	71,581	73,834	73,901	427,883	842,513	777,704	64,809
42	Turkey Point Cooling Canal Monitoring Plar	33,738	33,695	33,652	33,609	33,566	33,523	201,784	407,704	376,342	31,362
44	Barley Barber Swamp Iron Mitigation	0	0	0	942	1,595	1,593	4,130	4,130	4,130	
2	Total Investment Projects - Recoverable Costs	$ 12,617,229	$ 12,656,464	$ 12,686,404	$ 12,718,365	$ 12,742,957	$ 12,845,659	$ 76,267,078	$ 150,377,367	$ 127,343,239	$ 23,034,128
3	Recoverable Costs Allocated to Energy	$ 1,925,225	$ 1,926,449	$ 1,926,958	$ 1,927,550	$ 1,927,597	$ 1,933,704	$ 11,567,482	$ 23,034,128		
4	Recoverable Costs Allocated to Demand	$ 10,692,005	$ 10,730,015	$ 10,759,446	$ 10,790,815	$ 10,815,359	$ 10,911,955	$ 64,699,596	$ 127,343,239		
5	Retail Energy Jurisdictional Factor	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%				
6	Retail Demand Jurisdictional Factor	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%				
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,887,242	$ 1,888,442	$ 1,888,941	$ 1,889,521	$ 1,889,568	$ 1,895,554	$ 11,339,268	$ 22,579,688		
8	Jurisdictional Demand Recoverable Costs (C)	$ 10,481,484	$ 10,518,747	$ 10,547,598	$ 10,578,349	$ 10,602,410	$ 10,697,105	$ 63,425,693	$ 124,835,914		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 12,368,726	$ 12,407,188	$ 12,436,539	$ 12,467,870	$ 12,491,978	$ 12,592,658	$ 74,764,961	$ 147,415,602		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	n/a
3.	Less: Accumulated Depreciation	$8,813,243	8,833,019	8,852,794	8,872,569	8,892,345	8,912,120	8,931,895	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,083,559	$1,063,784	$1,044,009	$1,024,234	$1,004,458	$984,683	$964,908	n/a
6.	Average Net Investment		1,073,672	1,053,897	1,034,121	1,014,346	994,571	974,795	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,849	6,723	6,597	6,471	6,344	6,218	$39,202
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,742	1,710	1,678	1,646	1,614	1,582	$9,973
8.	Investment Expenses								
	a. Depreciation (E)		19,775	19,775	19,775	19,775	19,775	19,775	$118,652
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$28,367	$28,208	$28,050	$27,892	$27,734	$27,575	$167,826

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	n/a
3.	Less: Accumulated Depreciation	$8,931,895	8,951,670	8,971,446	8,991,221	9,010,996	9,030,772	9,050,547	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$964,908	$945,132	$925,357	$905,582	$885,807	$866,031	$846,256	n/a
6.	Average Net Investment		955,020	935,245	915,469	895,694	875,919	856,144	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,092	5,966	5,840	5,714	5,587	5,461	73,862
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,550	1,518	1,486	1,454	1,421	1,389	18,790
8.	Investment Expenses								
	a. Depreciation (E)		19,775	19,775	19,775	19,775	19,775	19,775	237,303
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$27,417	$27,259	$27,101	$26,942	$26,784	$26,626	$329,955

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	n/a
3.	Less: Accumulated Depreciation	$6,092,959	6,117,360	6,141,762	6,166,163	6,190,565	6,214,966	6,239,368	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,139,517	$4,115,115	$4,090,713	$4,066,312	$4,041,910	$4,017,509	$3,993,107	n/a
6.	Average Net Investment		4,127,316	4,102,914	4,078,513	4,054,111	4,029,710	4,005,308	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		26,328	26,172	26,017	25,861	25,706	25,550	$155,634
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,698	6,658	6,619	6,579	6,539	6,500	$39,593
8.	Investment Expenses								
	a. Depreciation (E)		24,402	24,402	24,402	24,402	24,402	24,402	$146,409
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$57,428	$57,232	$57,037	$56,842	$56,646	$56,451	$341,636

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	n/a
3.	Less: Accumulated Depreciation	$6,239,368	6,263,770	6,288,171	6,312,573	6,336,974	6,361,376	6,385,777	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,993,107	$3,968,706	$3,944,304	$3,919,902	$3,895,501	$3,871,099	$3,846,698	n/a
6.	Average Net Investment		3,980,906	3,956,505	3,932,103	3,907,702	3,883,300	3,858,899	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		25,394	25,239	25,083	24,927	24,772	24,616	305,864
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,460	6,421	6,381	6,341	6,302	6,262	77,760
8.	Investment Expenses								
	a. Depreciation (E)		24,402	24,402	24,402	24,402	24,402	24,402	292,819
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$56,256	$56,061	$55,865	$55,670	$55,475	$55,280	$676,243

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$41,612	41,612	41,612	41,612	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$28,091	28,161	28,230	28,300	28,369	28,439	28,508	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$13,520	$13,451	$13,381	$13,312	$13,242	$13,173	$13,103	n/a
6.	Average Net Investment		13,486	13,416	13,347	13,277	13,208	13,138	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		86	86	85	85	84	84	$510
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		22	22	22	22	21	21	$130
8.	Investment Expenses								
	a. Depreciation (E)		70	70	70	70	70	70	$417
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$177	$177	$176	$176	$175	$175	$1,056

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.
(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$41,612	41,612	41,612	41,612	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$28,508	28,578	28,647	28,717	28,786	28,856	28,925	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$13,103	$13,034	$12,964	$12,895	$12,825	$12,756	$12,686	n/a
6.	Average Net Investment		13,069	12,999	12,930	12,860	12,791	12,721	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		83	83	82	82	82	81	1,003
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		21	21	21	21	21	21	255
8.	Investment Expenses								
	a. Depreciation (E)		70	70	70	70	70	70	834
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$174	$174	$173	$172	$172	$171	$2,092

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	($7,176)	($7,176)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$11,733,316	11,733,316	11,733,316	11,733,316	11,733,316	11,733,316	11,726,140	n/a
3.	Less: Accumulated Depreciation	$3,719,660	3,743,150	3,766,640	3,790,130	3,813,620	3,837,110	3,860,592	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,013,656	$7,990,166	$7,966,676	$7,943,186	$7,919,696	$7,896,206	$7,865,548	n/a
6.	Average Net Investment		8,001,911	7,978,421	7,954,931	7,931,441	7,907,951	7,880,877	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		51,044	50,894	50,744	50,595	50,445	50,272	$303,995
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,986	12,947	12,909	12,871	12,833	12,789	$77,335
8.	Investment Expenses								
	a. Depreciation (E)		23,490	23,490	23,490	23,490	23,490	23,482	$140,932
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$87,520	$87,332	$87,144	$86,956	$86,768	$86,543	$522,262

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($7,176)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$11,726,140	11,726,140	11,726,140	11,726,140	11,726,140	11,726,140	11,726,140	n/a
3.	Less: Accumulated Depreciation	$3,860,592	3,884,066	3,907,540	3,931,014	3,954,488	3,977,962	4,001,436	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,865,548	$7,842,074	$7,818,600	$7,795,126	$7,771,652	$7,748,178	$7,724,705	n/a
6.	Average Net Investment		7,853,811	7,830,337	7,806,863	7,783,389	7,759,915	7,736,441	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		50,099	49,950	49,800	49,650	49,500	49,351	602,345
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,745	12,707	12,669	12,631	12,593	12,555	153,235
8.	Investment Expenses								
	a. Depreciation (E)		23,474	23,474	23,474	23,474	23,474	23,474	281,775
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$86,319	$86,131	$85,943	$85,755	$85,567	$85,379	$1,037,356

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation	$21,643	21,705	21,768	21,830	21,892	21,954	22,016	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,387	$9,325	$9,262	$9,200	$9,138	$9,076	$9,014	n/a
6.	Average Net Investment		9,356	9,293	9,231	9,169	9,107	9,045	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		60	59	59	58	58	58	$352
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		15	15	15	15	15	15	$90
8.	Investment Expenses								
	a. Depreciation (E)		62	62	62	62	62	62	$372
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$137	$136	$136	$135	$135	$134	$814

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation	$22,016	22,078	22,140	22,202	22,264	22,326	22,388	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,014	$8,952	$8,890	$8,828	$8,766	$8,704	$8,642	n/a
6.	Average Net Investment		8,983	8,921	8,859	8,797	8,735	8,673	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		57	57	57	56	56	55	690
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		15	14	14	14	14	14	176
8.	Investment Expenses								
	a. Depreciation (E)		62	62	62	62	62	62	745
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$134	$133	$133	$132	$132	$131	$1,610

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 6b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($1,682)	$4,413	$0	$0	$0	$0	$2,731
	c. Retirements		($1,682)	$41	$0	$0	$0	$0	($1,641)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$540,143	538,461	542,874	542,874	542,874	542,874	542,874	n/a
3.	Less: Accumulated Depreciation	$269,677	274,697	281,446	288,154	294,883	301,591	308,299	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$270,466	$263,764	$261,428	$254,720	$247,991	$241,283	$234,575	n/a
6.	Average Net Investment		267,115	262,596	258,074	251,355	244,637	237,929	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,704	1,675	1,646	1,603	1,561	1,518	$9,707
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		433	426	419	408	397	386	$2,469
8.	Investment Expenses								
	a. Depreciation (E)		6,702	6,708	6,708	6,729	6,708	6,708	$40,263
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,839	$8,809	$8,773	$8,740	$8,666	$8,612	$52,439

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	($12,013)	$78,692	($37)	$12	$354,914	$424,298
	c. Retirements		$0	($12,052)	$0	$0	($2,345)	($72,449)	($88,487)
	d. Other								0
2.	Plant-In-Service/Depreciation Base (A)	$542,874	542,874	530,861	609,553	609,515	609,528	964,442	n/a
3.	Less: Accumulated Depreciation	$308,299	314,969	309,481	316,651	323,675	328,352	263,094	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$234,575	$227,905	$221,380	$292,901	$285,841	$281,175	$701,348	n/a
6.	Average Net Investment		231,240	224,642	257,141	289,371	283,508	491,262	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,475	1,433	1,640	1,848	1,808	3,134	21,043
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		375	365	417	470	460	797	5,353
8.	Investment Expenses								
	a. Depreciation (E)		6,670	6,564	7,171	7,023	7,023	7,191	81,904
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,520	$8,361	$9,228	$9,339	$9,292	$11,122	$108,301

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3. Less: Accumulated Depreciation	$51,106	51,282	51,459	51,636	51,812	51,989	52,166	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$66,688	$66,512	$66,335	$66,158	$65,981	$65,805	$65,628	n/a
6. Average Net Investment		66,600	66,423	66,248	66,070	65,893	65,716	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		425	424	423	421	420	419	$2,532
b. Debt Component (Line 6 x debt rate x 1/12) (C)		108	108	108	107	107	107	$644
8. Investment Expenses								
a. Depreciation (E)		177	177	177	177	177	177	$1,060
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$710	$708	$707	$705	$704	$703	$4,236

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation	$52,166	52,342	52,519	52,696	52,873	53,049	53,226	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$65,628	$65,451	$65,275	$65,098	$64,921	$64,745	$64,568	n/a
6.	Average Net Investment		65,540	65,363	65,186	65,010	64,833	64,656	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		418	417	416	415	414	412	5,024
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		106	106	106	105	105	105	1,278
8.	Investment Expenses								
	a. Depreciation (E)		177	177	177	177	177	177	2,120
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$701	$700	$698	$697	$695	$694	$8,422

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation	$461,625	463,257	464,889	466,522	468,154	469,786	471,419	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$402,636	$401,003	$399,371	$397,739	$396,107	$394,474	$392,842	n/a
6.	Average Net Investment		401,820	400,187	398,555	396,923	395,290	393,658	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,563	2,553	2,542	2,532	2,522	2,511	$15,223
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		652	649	647	644	641	639	$3,873
8.	Investment Expenses								
	a. Depreciation (E)		1,632	1,632	1,632	1,632	1,632	1,632	$9,794
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,848	$4,836	$4,821	$4,808	$4,795	$4,782	$28,890

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	($9,937)	($9,937)
	c. Retirements		$0	$0	$0	$0	$0	($9,937)	($9,937)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$864,260	864,260	864,260	864,260	864,260	864,260	854,324	n/a
3.	Less: Accumulated Depreciation	$471,419	473,051	474,683	476,316	477,948	479,580	471,276	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$392,842	$391,210	$389,577	$387,945	$386,313	$384,680	$383,048	n/a
6.	Average Net Investment		392,026	390,393	388,761	387,129	385,496	383,864	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,501	2,490	2,480	2,469	2,459	2,449	30,071
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		636	634	631	628	626	623	7,650
8.	Investment Expenses								
	a. Depreciation (E)		1,632	1,632	1,632	1,632	1,632	1,632	19,588
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,769	$4,756	$4,743	$4,730	$4,717	$4,704	$57,309

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$3,364	$484	$1,498	($233,856)	$0	($245)	($228,754)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,462,862	1,466,226	1,466,710	1,468,208	1,234,352	1,234,352	1,234,108	n/a
3.	Less: Accumulated Depreciation	$214,251	217,036	219,823	222,612	225,216	227,636	230,056	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,248,611	$1,249,191	$1,246,887	$1,245,596	$1,009,136	$1,006,716	$1,004,052	n/a
6.	Average Net Investment		1,248,901	1,248,039	1,246,242	1,127,366	1,007,926	1,005,384	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		7,967	7,961	7,950	7,191	6,430	6,413	$43,912
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		2,027	2,025	2,022	1,829	1,636	1,632	$11,171
8.	Investment Expenses								
	a. Depreciation (E)		2,784	2,787	2,789	2,605	2,420	2,420	$15,804
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$12,778	$12,774	$12,761	$11,626	$10,485	$10,464	$70,887

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$964	($1)	$0	$0	$0	($227,792)
	c. Retirements		$0	($267)	$0	$0	$0	$0	($267)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,234,108	1,234,108	1,235,071	1,235,070	1,235,070	1,235,070	1,235,070	n/a
3.	Less: Accumulated Depreciation	$230,058	230,994	233,147	235,568	237,988	240,409	242,830	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,004,052	$1,003,114	$1,001,925	$999,503	$997,082	$994,661	$992,240	n/a
6.	Average Net Investment		1,003,583	1,002,519	1,000,714	998,292	995,872	993,451	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,402	6,395	6,384	6,368	6,353	6,337	82,151
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,629	1,627	1,624	1,620	1,616	1,612	20,899
8.	Investment Expenses								
	a. Depreciation (E)		938	2,420	2,421	2,421	2,421	2,421	28,846
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,969	$10,442	$10,428	$10,409	$10,390	$10,370	$131,895

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$352,942	352,942	352,942	352,942	352,942	352,942	352,942	n/a
3.	Less: Accumulated Depreciation	($690,552)	(690,023)	(689,494)	(688,964)	(688,435)	(687,905)	(687,376)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,043,495	$1,042,965	$1,042,436	$1,041,907	$1,041,377	$1,040,848	$1,040,318	n/a
6.	Average Net Investment		1,043,230	1,042,701	1,042,171	1,041,642	1,041,112	1,040,583	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,655	6,651	6,648	6,645	6,641	6,638	$39,878
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,693	1,692	1,691	1,690	1,690	1,689	$10,145
8.	Investment Expenses								
	a. Depreciation (E)		529	529	529	529	529	529	$3,176
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,877	$8,873	$8,869	$8,864	$8,860	$8,856	$53,199

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	($109)	($2,650)	($2,659)	($5,125)	($2,663)	($13,207)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$352,942	352,942	352,942	352,942	352,942	352,942	352,942	n/a
3.	Less: Accumulated Depreciation	($687,376)	(686,847)	(686,426)	(688,547)	(690,677)	(695,273)	(697,407)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,040,318	$1,039,789	$1,039,369	$1,041,490	$1,043,619	$1,048,215	$1,050,349	n/a
6.	Average Net Investment		1,040,054	1,039,579	1,040,429	1,042,555	1,045,917	1,049,282	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,635	6,631	6,637	6,650	6,672	6,693	79,797
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,688	1,687	1,688	1,692	1,697	1,703	20,300
8.	Investment Expenses								
	a. Depreciation (E)		529	529	529	529	529	529	6,353
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,852	$8,848	$8,855	$8,872	$8,899	$8,926	$106,449

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
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	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
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	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$30,438	$150,212	$17,847	$14	$50,365	$367,059	$625,732
	c. Retirements		$0	$4,216	($34,021)	$0	$0	$0	($29,805)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$19,346,601	19,377,037	19,527,249	19,544,896	19,544,909	19,605,274	19,972,333	n/a
3.	Less: Accumulated Depreciation	$2,881,354	2,919,793	2,962,694	2,967,405	3,006,157	3,044,964	3,084,115	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,465,247	$16,457,244	$16,564,555	$16,577,491	$16,538,752	$16,560,310	$16,888,217	n/a
6.	Average Net Investment		16,461,246	16,510,899	16,571,023	16,558,122	16,549,531	16,724,264	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		105,006	105,323	105,707	105,624	105,569	106,684	$633,914
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		26,713	26,794	26,891	26,871	26,857	27,140	$161,266
8.	Investment Expenses								
	a. Depreciation (E)		38,439	38,686	38,731	38,753	38,807	39,151	$232,567
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$170,158	$170,803	$171,329	$171,247	$171,233	$172,976	$1,027,746

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$178	$0	($3,037)	$29,779	$1,561	($2)	$854,211
	c. Retirements		$0	$0	($3,037)	$0	$0	$0	($32,842)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$19,972,333	19,972,511	19,972,511	19,969,474	19,999,252	20,000,814	20,000,812	n/a
3.	Less: Accumulated Depreciation	$3,084,115	3,123,557	3,163,000	3,199,402	3,238,860	3,278,343	3,317,828	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,888,217	$16,848,953	$16,809,511	$16,770,072	$16,760,392	$16,722,471	$16,682,984	n/a
6.	Average Net Investment		16,868,585	16,829,232	16,789,792	16,765,232	16,741,431	16,702,727	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		107,605	107,354	107,102	106,945	106,794	106,547	1,276,260
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		27,374	27,310	27,246	27,207	27,168	27,105	324,677
8.	Investment Expenses								
	a. Depreciation (E)		39,442	39,442	39,439	39,459	39,483	39,484	469,316
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$174,421	$174,106	$173,787	$173,611	$173,445	$173,136	$2,070,253

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	n/a
3.	Less: Accumulated Depreciation	$4,824,395	4,893,186	4,961,977	5,030,767	5,099,558	5,168,349	5,237,140	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$26,925,151	$26,856,361	$26,787,570	$26,718,779	$26,649,989	$26,581,198	$26,512,407	n/a
6.	Average Net Investment		26,890,756	26,821,965	26,753,175	26,684,384	26,615,593	26,546,802	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		171,536	171,097	170,658	170,220	169,781	169,342	$1,022,634
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		43,638	43,527	43,415	43,303	43,192	43,080	$260,155
8.	Investment Expenses								
	a. Depreciation (E)		68,791	68,791	68,791	68,791	68,791	68,791	$412,744
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$283,965	$283,415	$282,864	$282,314	$281,763	$281,213	$1,695,534

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	n/a
3.	Less: Accumulated Depreciation	$5,237,140	5,305,930	5,374,721	5,443,512	5,512,302	5,581,093	5,649,884	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$26,512,407	$26,443,616	$26,374,826	$26,306,035	$26,237,244	$26,168,454	$26,099,663	n/a
6.	Average Net Investment		26,478,012	26,409,221	26,340,430	26,271,640	26,202,849	26,134,058	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		168,903	168,464	168,026	167,587	167,148	166,709	2,029,471
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		42,969	42,857	42,745	42,634	42,522	42,410	516,292
8.	Investment Expenses								
	a. Depreciation (E)		68,791	68,791	68,791	68,791	68,791	68,791	825,488
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$280,662	$280,112	$279,562	$279,011	$278,461	$277,910	$3,371,252

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.
(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$14,251,762	14,403,579	14,555,396	14,707,212	14,859,029	15,010,845	15,162,662	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$67,649,407	$67,497,590	$67,345,774	$67,193,957	$67,042,141	$66,890,324	$66,738,507	n/a
6.	Average Net Investment		67,573,499	67,421,682	67,269,866	67,118,049	66,966,232	66,814,416	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		431,051	430,083	429,114	428,146	427,178	426,209	$2,571,781
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		109,658	109,412	109,166	108,919	108,673	108,426	$654,254
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	$910,900
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$692,526	$691,311	$690,097	$688,882	$687,667	$686,452	$4,136,935

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$15,162,662	15,314,479	15,466,295	15,618,112	15,769,928	15,921,745	16,073,562	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$66,738,507	$66,586,691	$66,434,874	$66,283,058	$66,131,241	$65,979,424	$65,827,608	n/a
6.	Average Net Investment		66,662,599	66,510,783	66,358,966	66,207,149	66,055,333	65,903,516	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		425,241	424,272	423,304	422,335	421,367	420,398	5,108,698
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		108,180	107,934	107,687	107,441	107,195	106,948	1,299,639
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	1,821,799
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$685,237	$684,022	$682,808	$681,593	$680,378	$679,163	$8,230,136

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	($377,470)	$0	$0	($377,470)
	c. Retirements		$0	$0	$0	($377,470)	$0	$0	($377,470)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$492,916	492,916	492,916	492,916	115,447	115,447	115,447	n/a
3.	Less: Accumulated Depreciation	$39,741	40,604	41,467	42,329	(334,608)	(334,406)	(334,204)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$453,175	$452,312	$451,450	$450,587	$450,055	$449,853	$449,651	n/a
6.	Average Net Investment		452,744	451,881	451,018	450,321	449,954	449,752	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,888	2,883	2,877	2,873	2,870	2,869	$17,259
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		735	733	732	731	730	730	$4,391
8.	Investment Expenses								
	a. Depreciation (E)		863	863	863	532	202	202	$3,524
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,485	$4,478	$4,472	$4,136	$3,802	$3,801	$25,174

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($377,470)
	c. Retirements		$345,901	$0	$0	$0	$427	$0	($31,142)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$115,447	115,447	115,447	115,447	115,447	115,447	115,447	n/a
3.	Less: Accumulated Depreciation	($334,204)	11,899	12,101	12,303	12,505	13,134	13,336	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$449,651	$103,548	$103,346	$103,144	$102,942	$102,313	$102,111	n/a
6.	Average Net Investment		276,599	103,447	103,245	103,043	102,628	102,212	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,764	660	659	657	655	652	22,306
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		449	168	168	167	167	166	5,675
8.	Investment Expenses								
	a. Depreciation (E)		202	202	202	202	202	202	4,736
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,415	$1,030	$1,028	$1,027	$1,023	$1,020	$32,717

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$430,045	$5,719,099	$6,805,898	$4,893,543	$4,511,190	$6,001,791	$28,361,566
	b. Clearings to Plant		$4,817,580	$419,697	($52,658,030)	$38,063,064	$15,395,820	$4,034,816	$10,072,947
	c. Retirements		$0	$6,970	$4,413	$0	$0	$0	$11,384
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$154,714,081	159,531,661	159,951,358	107,293,328	145,356,392	160,752,212	164,787,028	n/a
3.	Less: Accumulated Depreciation	$4,936,729	5,278,356	5,633,487	5,929,265	6,286,984	6,636,771	7,040,735	n/a
4.	CWIP - Non Interest Bearing	$253,353,253	249,173,523	254,892,622	261,698,521	266,592,063	271,103,253	273,076,754	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$403,130,605	$403,426,828	$409,210,493	$363,062,584	$405,661,471	$425,218,694	$430,823,047	n/a
6.	Average Net Investment		403,278,717	406,318,661	386,136,538	384,362,027	415,440,083	428,020,871	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,572,514	2,591,906	2,463,185	2,451,845	2,650,092	2,730,345	$15,459,886
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		654,441	659,374	628,622	623,743	674,176	694,592	$3,932,948
8.	Investment Expenses								
	a. Depreciation (E)		341,627	348,161	291,364	357,720	349,787	403,963	$2,092,623
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,568,582	$3,599,441	$3,381,151	$3,433,307	$3,674,055	$3,828,900	$21,485,437

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Jan & Feb 2010 - Debt component is 1.8767% reflects an 11.75% ROE. From March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$7,540,593	$8,402,647	$5,917,060	$6,037,398	$3,451,826	$25,008,623	$82,719,713
	b. Clearings to Plant		$518,275	$0	$0	$0	$0	$100,015	$10,691,237
	c. Retirements		($113)	($0)	$0	($22,255)	$6,483	$897	($3,825)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$164,787,028	165,305,303	165,305,303	165,305,303	165,305,303	165,305,303	165,405,318	n/a
3.	Less: Accumulated Depreciation	$7,040,735	7,399,713	7,759,365	8,119,017	8,456,415	8,822,529	9,183,187	n/a
4.	CWIP - Non Interest Bearing	$273,076,754	280,080,411	286,478,325	292,418,780	298,459,034	301,900,087	326,732,729	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$430,823,047	$437,986,001	$444,024,263	$449,605,065	$455,307,923	$458,382,860	$482,954,860	n/a
6.	Average Net Investment		434,404,524	441,005,132	446,814,664	452,456,494	456,845,391	470,668,860	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,771,066	2,813,171	2,850,230	2,886,219	2,914,216	3,002,396	32,897,166
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		704,952	715,663	725,091	734,246	741,369	763,801	8,318,070
8.	Investment Expenses								
	a. Depreciation (E)		359,091	359,652	359,652	359,652	359,652	359,761	4,250,083
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,835,108	$3,888,487	$3,934,973	$3,980,118	$4,015,237	$4,125,958	$45,265,319

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Jan & Feb 2010 - Debt component is 1.8767% reflects an 11.75% ROE. From March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($21,691)	$199,294	$204,880	$231,090	$242,381	($320,135)	$535,818
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$105,905,052	105,883,361	106,082,655	106,287,535	106,518,624	106,761,006	106,440,871	n/a
3.	Less: Accumulated Depreciation	$1,882,324	2,111,762	2,341,392	2,571,459	2,801,999	3,033,052	3,264,021	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$104,022,728	$103,771,600	$103,741,263	$103,716,075	$103,716,625	$103,727,954	$103,176,850	n/a
6.	Average Net Investment		103,897,164	103,756,432	103,728,669	103,716,350	103,722,289	103,452,402	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		662,760	661,862	661,685	661,606	661,644	659,923	$3,969,481
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		168,604	168,376	168,331	168,311	168,321	167,883	$1,009,825
8.	Investment Expenses								
	a. Depreciation (E)		229,437	229,630	230,068	230,540	231,053	230,969	$1,381,697
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,060,802	$1,059,868	$1,060,084	$1,060,457	$1,061,018	$1,058,774	$6,361,002

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$117,697	$43,389	$102,691	$18,098	$42,694	$115,670	$974,039
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$106,440,871	106,558,568	106,601,937	106,704,628	106,720,726	106,763,421	106,879,091	n/a
3.	Less: Accumulated Depreciation	$3,264,021	3,494,770	3,725,692	3,956,764	4,187,959	4,419,214	4,650,632	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$103,176,850	$103,063,797	$102,876,245	$102,747,864	$102,532,768	$102,344,207	$102,228,459	n/a
6.	Average Net Investment		103,120,324	102,970,021	102,812,054	102,640,316	102,438,487	102,286,333	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		657,804	656,846	655,838	654,742	653,455	652,484	7,900,651
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		167,344	167,100	166,843	166,565	166,237	165,990	2,009,904
8.	Investment Expenses								
	a. Depreciation (E)		230,749	230,922	231,072	231,195	231,255	231,418	2,788,308
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,055,897	$1,054,867	$1,053,754	$1,052,502	$1,050,947	$1,049,893	$12,678,863

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$147,578	$147,578
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$235,391	235,391	235,391	235,391	235,391	235,391	382,969	n/a
3.	Less: Accumulated Depreciation	$8,710	9,122	9,534	9,946	10,358	10,770	11,311	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$226,681	$226,269	$225,857	$225,445	$225,033	$224,621	$371,658	n/a
6.	Average Net Investment		226,475	226,063	225,651	225,239	224,827	298,140	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,445	1,442	1,439	1,437	1,434	1,902	$9,099
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		368	367	366	366	365	484	$2,315
8.	Investment Expenses								
	a. Depreciation (E)		412	412	412	412	412	541	$2,601
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,224	$2,221	$2,218	$2,214	$2,211	$2,927	$14,015

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$3,385	$13,759	($14)	($164,709)	$0	$0	$0
	c. Retirements		$0	$0	$0	($955)	$0	$0	($955)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$382,969	386,355	400,114	400,100	235,391	235,391	235,391	n/a
3.	Less: Accumulated Depreciation	$11,311	11,984	12,672	13,373	12,830	13,242	13,654	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$371,658	$374,371	$387,442	$386,727	$222,562	$222,150	$221,738	n/a
6.	Average Net Investment		373,015	380,906	387,084	304,644	222,356	221,944	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,379	2,430	2,469	1,943	1,418	1,416	21,155
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		605	618	628	494	361	360	5,382
8.	Investment Expenses								
	a. Depreciation (E)		673	688	700	412	412	412	5,898
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,658	$3,736	$3,798	$2,850	$2,191	$2,188	$32,435

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$5,465,817	$345,053	$5,810,871
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	5,465,817	5,810,871	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	0	4,099	12,557	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$5,461,718	$5,798,314	n/a
6.	Average Net Investment		0	0	0	0	2,730,859	5,630,016	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	17,420	35,914	$53,334
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	4,432	9,136	$13,568
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	4,099	8,458	$12,557
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$25,951	$53,508	$79,459

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$410,784	($10,312)	$72,919	$36,318	$282,540	($153,426)	$6,449,693
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$5,810,871	6,221,654	6,211,342	6,284,261	6,320,579	6,603,119	6,449,693	n/a
3.	Less: Accumulated Depreciation	$12,557	21,581	30,906	40,278	49,731	59,424	69,214	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,798,314	$6,200,073	$6,180,436	$6,243,984	$6,270,848	$6,543,695	$6,380,480	n/a
6.	Average Net Investment		5,999,193	6,190,255	6,212,210	6,257,416	6,407,271	6,462,087	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		38,269	39,488	39,628	39,916	40,872	41,222	292,728
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		9,735	10,046	10,081	10,155	10,398	10,487	74,469
8.	Investment Expenses								
	a. Depreciation (E)		9,024	9,325	9,372	9,454	9,693	9,790	69,214
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$57,029	$58,858	$59,081	$59,524	$60,962	$61,498	$436,411

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.
(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions		$164,005	$125,045	$263,198	$211,038	$0	$0	$763,285
b.	Clearings to Plant		$132,320	$10,675	$13,719	$1,549	$827,101	$3,937	$989,301
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$151,221,418	151,353,738	151,364,413	151,378,132	151,379,681	152,206,782	152,210,719	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$5,939,454	6,359,233	6,779,208	7,199,283	7,619,317	8,040,478	8,462,880	n/a
4.	CWIP - Non Interest Bearing	$21,109	185,114	310,159	573,357	782,845	(0)	(0)	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$145,303,073	$145,179,619	$144,895,364	$144,752,208	$144,543,209	$144,166,304	$143,747,839	n/a
6.	Average Net Investment		145,241,346	145,037,491	144,823,785	144,647,707	144,354,757	143,957,071	n/a
a.	Average ITC Balance		42,173,913	42,051,847	41,929,781	41,807,715	41,685,649	41,563,583	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		999,616	998,104	996,530	995,195	993,114	990,366	$5,972,925
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		244,930	244,572	244,198	243,886	243,384	242,712	$1,463,682
8.	Investment Expenses								
a.	Depreciation (E)		413,720	413,916	414,016	413,975	415,102	416,343	$2,487,072
b.	Amortization (F)								
c.	Dismantlement (G)		6,059	6,059	6,059	6,059	6,059	6,059	$36,354
d.	Property Expenses								
e.	Amortization ITC Solar		(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	($962,370)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,503,930	$1,502,257	$1,500,408	$1,498,720	$1,497,265	$1,495,084	$8,997,863

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions		($635)	$11,921	$19,845	$0	$0	$0	$794,417
b.	Clearings to Plant		$15,928	($629)	$625	$36,834	($88,368)	$571,742	$1,525,434
c.	Retirements		$0	$0	$636	$0	$0	$0	$636
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$152,210,719	152,226,647	152,226,018	152,226,644	152,263,478	152,175,110	152,746,852	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$8,462,880	8,885,316	9,307,772	9,730,865	10,153,432	10,575,894	10,999,047	n/a
4.	CWIP - Non Interest Bearing	($0)	(636)	(0)	(0)	(0)	(0)	(0)	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$143,747,839	$143,340,696	$142,918,245	$142,495,779	$142,110,046	$141,599,215	$141,747,805	n/a
6.	Average Net Investment	143,957,071	143,544,267	143,129,471	142,707,012	142,302,912	141,854,631	141,673,510	n/a
a.	Average ITC Balance	41,563,583	41,441,517	41,319,451	41,197,385	41,075,319	40,953,253	40,831,187	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		987,521	984,663	981,757	978,967	975,896	974,529	11,856,259
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		242,015	241,315	240,603	239,921	239,166	238,846	2,905,548
8.	Investment Expenses								
a.	Depreciation (E)		416,377	416,398	416,398	416,508	416,404	417,093	4,986,249
b.	Amortization (F)								
c.	Dismantlement (G)		6,059	6,059	6,059	6,059	6,059	6,059	$72,708
d.	Property Expenses								
e.	Amortization ITC Solar		(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	($1,924,740)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,491,577	$1,488,040	$1,484,421	$1,481,060	$1,477,130	$1,476,132	$17,896,024

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$1,929	($283)	$33,216	$3,301	($2)	$903	$39,065
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$70,583,766	70,585,695	70,585,412	70,618,629	70,621,929	70,621,928	70,622,831	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$1,678,307	1,875,804	2,073,303	2,270,859	2,468,508	2,666,155	2,863,785	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$68,905,459	$68,709,891	$68,512,110	$68,347,770	$68,153,422	$67,955,773	$67,759,047	n/a
6.	Average Net Investment		68,807,675	68,611,000	68,429,940	68,250,596	68,054,597	67,857,410	n/a
a.	Average ITC Balance		17,967,207	17,916,018	17,864,829	17,813,640	17,762,451	17,711,262	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		470,076	468,733	467,489	466,256	464,917	463,571	$2,801,041
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		115,594	115,264	114,959	114,656	114,327	113,996	$688,796
8.	Investment Expenses								
a.	Depreciation (E)		194,585	194,587	194,644	194,737	194,735	194,718	$1,168,005
b.	Amortization (F)								
c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	$17,472
d.	Property Expenses								
e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	($403,578)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$715,904	$714,232	$712,740	$711,299	$709,628	$707,933	$4,271,737

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1. Investments									
a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$5,130	$3	$5,393	$0	$0	$0	$49,591
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2. Plant-In-Service/Depreciation Base (A)		$70,622,831	70,627,961	70,627,964	70,633,358	70,633,358	70,633,358	70,633,358	n/a
3. Less: Accumulated Depreciation & Dismantlement		$2,863,785	3,061,448	3,259,146	3,456,878	3,655,297	3,853,056	4,049,709	n/a
4. CWIP - Non Interest Bearing		$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)		$67,759,047	$67,566,513	$67,368,818	$67,176,480	$66,978,060	$66,780,302	$66,583,649	n/a
6. Average Net Investment			67,662,780	67,467,666	67,272,649	67,077,270	66,879,181	66,681,976	n/a
a.	Average ITC Balance	$17,711,262	17,660,073	17,608,884	17,557,695	17,506,506	17,455,317	17,404,128	
7. Return on Average Net Investment									
a.	Equity Component grossed up for taxes (B)		462,240	460,907	459,574	458,239	456,887	455,540	5,554,428
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		113,669	113,341	113,013	112,685	112,353	112,021	1,365,879
8. Investment Expenses									
a.	Depreciation (E)		194,752	194,788	194,820	195,507	194,846	193,741	2,336,458
b.	Amortization (F)								
c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	34,944
d.	Property Expenses								
e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(807,156)
9. Total System Recoverable Expenses (Lines 7 & 8)			$706,310	$704,683	$703,057	$702,080	$699,734	$696,951	$8,484,552

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(in Dollars)

Line			Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments									
	a.	Expenditures/Additions		$72,288	$16,250	$33,500	$47,708	4,655.61	7,243.14	$181,645
	b.	Clearings to Plant		$2,059,295	$687,522	$1,310,311	$315,220	$1,307,060	$311,605	$5,991,013
	c.	Retirements		$0	$759	$0	$0	$0	$0	$759
	d.	Other								
2.	Plant-In-Service/Depreciation Base (A)		$392,125,689	394,184,983	394,872,505	396,182,816	396,498,036	397,805,096	398,116,702	n/a
3.	Less: Accumulated Depreciation & Dismantlement		$858,379	1,968,380	3,082,905	4,200,130	5,320,430	6,442,994	7,567,817	n/a
4.	CWIP - Non Interest Bearing		$394,809	467,097	483,348	166,902	214,610	171,974	179,217	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$391,662,119	$392,683,701	$392,272,947	$392,149,588	$391,392,216	$391,534,076	$390,728,102	n/a
6.	Average Net Investment			392,172,910	392,478,324	392,211,268	391,770,902	391,463,146	391,131,089	n/a
	a.	Average ITC Balance		123,351,385	123,007,587	122,663,789	122,319,991	121,976,193	121,632,395	
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		2,715,540	2,716,892	2,714,592	2,711,187	2,708,628	2,705,914	$16,272,753
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		663,420	663,840	663,332	662,542	661,967	661,353	$3,978,453
8.	Investment Expenses									
	a.	Depreciation (E)		1,081,154	1,084,919	1,088,377	1,091,454	1,093,717	1,095,978	$6,535,598
	b.	Amortization (F)								
	c.	Dismantlement (G)		28,847	28,847	28,847	28,847	28,847	28,847	$173,082
	d.	Property Expenses								
	e.	Amortization ITC Solar		(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	($2,710,506)
9.	Total System Recoverable Expenses (Lines 7 & 8)			$4,037,210	$4,042,747	$4,043,397	$4,042,278	$4,041,408	$4,040,339	$24,247,380

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1. Investments									
a.	Expenditures/Additions		$4,913	$180,279	$532,715	$325,302	$325,079	$120,790	$1,670,723
b.	Clearings to Plant		$458,610	$0	$0	$0	$731,886	$236,074	$7,417,584
c.	Retirements		$0	$0	$0	$0	$0	$0	$759
d.	Other								
2. Plant-In-Service/Depreciation Base (A)		$398,116,702	398,575,312	398,575,312	398,575,312	398,575,312	399,307,198	399,543,272	n/a
3. Less: Accumulated Depreciation & Dismantlement		$7,567,817	8,693,699	9,820,211	10,946,723	12,073,235	13,200,753	14,329,802	n/a
4. CWIP - Non Interest Bearing		$179,217	179,217	179,612	409,342	628,489	851,958	973,287	n/a
5. Net Investment (Lines 2 - 3 + 4)		$390,728,102	$390,060,830	$388,934,713	$388,037,931	$387,130,566	$386,958,403	$386,186,957	n/a
6. Average Net Investment			390,394,466	389,497,771	388,486,322	387,584,248	387,044,484	386,572,680	n/a
a.	Average ITC Balance	$121,632,395	121,288,597	120,944,799	120,601,001	120,257,203	119,913,405	119,569,607	
7. Return on Average Net Investment									
a.	Equity Component grossed up for taxes (B)		2,700,819	2,694,303	2,687,254	2,680,904	2,676,865	2,673,259	32,385,958
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		660,082	658,552	656,835	655,296	654,345	653,504	7,915,067
8. Investment Expenses									
a.	Depreciation (E)		1,097,035	1,097,665	1,097,665	1,097,665	1,098,671	1,100,002	13,124,300
b.	Amortization (F)								
c.	Dismantlement (G)		28,847	28,847	28,847	28,847	28,847	28,847	346,164
d.	Property Expenses								
e.	Amortization ITC Solar		(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(5,421,012)
9. Total System Recoverable Expenses (Lines 7 & 8)			$4,034,832	$4,027,615	$4,018,850	$4,010,961	$4,006,977	$4,003,861	$48,350,476

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$203,250	$194,579	$35,286	$206	$3,003	($3,025)	$433,299
	c. Retirements		$2,061	$8,490	$10,609	$0	$0	$0	$21,160
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$7,412,851	7,616,101	7,810,680	7,845,966	7,846,172	7,849,175	7,846,151	n/a
3.	Less: Accumulated Depreciation	$44,776	54,071	70,051	88,401	96,144	103,890	111,628	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,368,075	$7,562,030	$7,740,629	$7,757,565	$7,750,028	$7,745,285	$7,734,523	n/a
6.	Average Net Investment		7,465,053	7,651,330	7,749,097	7,753,796	7,747,656	7,739,904	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		47,820	48,808	49,431	49,461	49,422	49,373	$294,115
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,114	12,417	12,575	12,583	12,573	12,560	$74,822
8.	Investment Expenses								
	a. Depreciation (E)		7,235	7,489	7,742	7,743	7,746	7,737	$45,692
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$66,968	$68,714	$69,749	$69,787	$69,741	$69,870	$414,630

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($6,013)	$4,654	($1)	$507,696	$32,038	($1,300)	$970,374
	c. Retirements		($6,893)	$4,654	$0	$0	$0	$1	$18,922
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$7,846,151	7,840,138	7,844,792	7,844,791	8,352,487	8,384,525	8,383,225	n/a
3.	Less: Accumulated Depreciation	$111,628	112,454	124,824	132,545	140,415	148,442	156,478	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,734,523	$7,727,684	$7,719,968	$7,712,246	$8,212,072	$8,236,083	$8,226,747	n/a
6.	Average Net Investment		7,731,103	7,723,826	7,716,107	7,962,159	8,224,078	8,231,415	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		49,317	49,270	49,221	50,791	52,461	52,508	597,684
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,546	12,534	12,522	12,921	13,346	13,358	152,049
8.	Investment Expenses								
	a. Depreciation (E)		7,719	7,716	7,722	7,870	8,027	8,035	92,780
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$69,581	$69,521	$69,464	$71,581	$73,834	$73,901	$842,513

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PTN Cooling Canal Monitoring System (Project No. 42)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$115,328	$2,766	($117,518)	($11,364)	$0	$0	($10,788)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$3,593,541	3,708,869	3,711,634	3,594,116	3,582,753	3,582,753	3,582,753	n/a
3.	Less: Accumulated Depreciation	$2,695	8,172	13,737	19,217	24,599	29,973	35,348	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,590,846	$3,700,697	$3,697,897	$3,574,900	$3,558,154	$3,552,779	$3,547,405	n/a
6.	Average Net Investment		3,645,771	3,699,297	3,636,398	3,566,527	3,555,467	3,550,092	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		23,256	23,598	23,197	22,751	22,680	22,646	$138,128
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		5,916	6,003	5,901	5,788	5,770	5,761	$35,139
8.	Investment Expenses								
	a. Depreciation (E)		5,477	5,565	5,479	5,383	5,374	5,374	$32,652
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$34,650	$35,166	$34,577	$33,921	$33,824	$33,781	$205,920

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PTN Cooling Canal Monitoring System (Project No. 42)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($10,788)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	n/a
3.	Less: Accumulated Depreciation	$35,348	40,722	46,096	51,470	56,844	62,218	67,592	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,547,405	$3,542,031	$3,536,657	$3,531,283	$3,525,909	$3,520,535	$3,515,161	n/a
6.	Average Net Investment		3,544,718	3,539,344	3,533,970	3,528,596	3,523,222	3,517,848	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		22,612	22,577	22,543	22,509	22,475	22,440	273,284
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		5,752	5,744	5,735	5,726	5,717	5,709	69,523
8.	Investment Expenses								
	a. Depreciation (E)		5,374	5,374	5,374	5,374	5,374	5,374	64,897
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$33,738	$33,695	$33,652	$33,609	$33,566	$33,523	$407,704

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Barley Barber Swamp Iron Mitigation (Project No. 44)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
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	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Barley Barber Swamp Iron Mitigation (Project No. 44)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$164,703	$2	($1)	$164,704
	c. Retirements		$0	$0	$0	$955	$0	$0	$955
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	164,703	164,705	164,704	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	1,243	1,531	1,820	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$163,460	$163,174	$162,885	n/a
6.	Average Net Investment		0	0	0	81,730	163,317	163,029	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	521	1,042	1,040	2,603
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	133	265	265	662
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	288	288	288	865
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$942	$1,595	$1,593	$4,130

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 53-57.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 53-57.

(F) Applicable amortization period(s). See Form 42-8A, pages 53-57.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line			Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount	
1	Working Capital Dr (Cr)										
	a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b	158.200 Allowances Withheld	0	0	0	0	0	0	0		
	c	182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
	d	254.900 Other Regulatory Liabilities-Gains	(2,054,468)	(2,033,042)	(2,011,616)	(1,990,190)	(1,968,764)	(1,950,542)	(1,929,071)		
2	Total Working Capital		($2,054,468)	($2,033,042)	($2,011,616)	($1,990,190)	($1,968,764)	($1,950,542)	($1,929,071)		
3	Average Net Working Capital Balance			(2,043,755)	(2,022,329)	(2,000,903)	(1,979,477)	(1,959,653)	(1,939,807)		
4	Return on Average Net Working Capital Balance										
	a	Equity Component grossed up for taxes (A)		(13,037)	(12,900)	(12,764)	(12,627)	(12,501)	(12,374)		
	b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,317)	(3,282)	(3,247)	(3,212)	(3,180)	(3,148)		
5	Total Return Component			($16,354)	($16,182)	($16,011)	($15,839)	($15,681)	($15,522)	($95,589)	(D)
6	Expense Dr (Cr)										
	a	411.800 Gains from Dispositions of Allowances		(21,426)	(21,426)	(21,426)	(21,426)	(23,500)	(38,921)		
	b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
	c	509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)			($21,426)	($21,426)	($21,426)	($21,426)	($23,500)	($38,921)	($148,125)	(E)
8	Total System Recoverable Expenses (Lines 5+7)			(37,780)	(37,608)	(37,437)	(37,265)	(39,181)	(54,443)		
	a	Recoverable Costs Allocated to Energy		(37,780)	(37,608)	(37,437)	(37,265)	(39,181)	(54,443)		
	b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9		Energy Jurisdictional Factor		98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%		
10		Demand Jurisdictional Factor		98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%		
11		Retail Energy-Related Recoverable Costs (B)		(37,034)	(36,866)	(36,698)	(36,530)	(38,408)	(53,368)		
12		Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)			($37,034)	($36,866)	($36,698)	($36,530)	($38,408)	($53,368)		

Notes:

(A) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(B) Line 8a times Line 9

(C) Line 8b times Line 10

(D) Line 5 is reported on Capital Schedule

(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability

Totals may not add due to rounding.

Form 42-8A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line			Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount	
1	Working Capital Dr (Cr)										
	a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b	158.200 Allowances Withheld	$0	0	0	0	0	0	0		
	c	182.300 Other Regulatory Assets-Losses	$0	0	0	0	0	0	0		
	d	254.900 Other Regulatory Liabilities-Gains	($1,929,071)	(1,907,175)	(1,885,279)	(1,863,384)	(1,841,488)	(1,819,592)	(1,797,695)		
2	Total Working Capital		($1,929,071)	($1,907,175)	($1,885,279)	($1,863,384)	($1,841,488)	($1,819,592)	($1,797,695)		
3	Average Net Working Capital Balance			(1,918,123)	(1,896,227)	(1,874,331)	(1,852,436)	(1,830,540)	(1,808,643)		
4	Return on Average Net Working Capital Balance										
	a	Equity Component grossed up for taxes (A)		(12,236)	(12,096)	(11,956)	(11,817)	(11,677)	(11,537)		
	b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,113)	(3,077)	(3,042)	(3,006)	(2,971)	(2,935)		
5	Total Return Component			($15,348)	($15,173)	($14,998)	($14,823)	($14,648)	($14,472)	($185,051)	(D)
6	Expense Dr (Cr)										
	a	411.800 Gains from Dispositions of Allowances		(21,896)	(21,896)	(21,896)	(21,896)	(21,896)	(21,897)		
	b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
	c	509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)			($21,896)	($21,896)	($21,896)	($21,896)	($21,896)	($21,897)	($279,502)	(E)
8	Total System Recoverable Expenses (Lines 5+7)			(37,244)	(37,069)	(36,894)	(36,719)	(36,544)	(36,369)		
	a	Recoverable Costs Allocated to Energy		(37,244)	(37,069)	(36,894)	(36,719)	(36,544)	(36,369)		
	b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9		Energy Jurisdictional Factor		98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%		
10		Demand Jurisdictional Factor		98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%		
11		Retail Energy-Related Recoverable Costs (B)		(36,510)	(36,338)	(36,166)	(35,994)	(35,823)	(35,652)		
12		Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)			($36,510)	($36,338)	($36,166)	($35,994)	($35,823)	($35,652)		

Notes:

(A) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Actual Balance December 2011
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	2,689,232.57	2,689,232.57
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.50%	2,563,376.41	2,563,376.41
	02 - Steam Generation Plant	Turkey Pt U2	31200	2.50%	2,275,221.65	2,275,221.65
02 - Low NOX Burner Technology Total					**9,896,802.90**	**9,896,802.90**
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	Cutler Comm	31100	1.70%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	2.20%	36,276.52	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	2.20%	310,454.41	310,454.41
	02 - Steam Generation Plant	Cutler U6	31200	2.20%	311,861.95	311,861.95
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	2.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	477,896.88	477,896.88
	02 - Steam Generation Plant	Manatee U2	31100	2.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	508,552.43	508,552.43
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	2.10%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	2.60%	529,318.55	529,318.55
	02 - Steam Generation Plant	Martin U2	31100	2.10%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	2.60%	525,201.70	525,201.70
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.30%	67,787.69	67,787.69
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	458,060.74	458,060.74
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	480,321.84	480,321.84
	02 - Steam Generation Plant	PtEverglades U3	31200	2.30%	507,658.33	507,658.33
	02 - Steam Generation Plant	PtEverglades U4	31200	2.30%	517,303.41	517,303.41
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	434,357.43	434,357.43
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	779.50	779.50
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	779.51	779.51
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.10%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm	31200	2.50%	37,954.50	37,954.50
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.50%	545,584.31	545,584.31
	02 - Steam Generation Plant	Turkey Pt U2	31200	2.50%	504,688.53	504,688.53
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	3.40%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	4.30%	462,254.20	462,254.20
	05 - Other Generation Plant	FtLauderdale U5	34300	4.20%	473,359.99	473,359.99
	05 - Other Generation Plant	FtMyers U2	34300	4.20%	23,619.18	23,619.18
	05 - Other Generation Plant	FtMyers U3	34300	5.20%	2,282.97	2,282.97
	05 - Other Generation Plant	Martin U3	34300	4.20%	416,872.29	416,872.29
	05 - Other Generation Plant	Martin U4	34300	4.20%	409,474.06	409,474.06
	05 - Other Generation Plant	Martin U8	34300	4.30%	13,693.21	13,693.21
	05 - Other Generation Plant	Putnam Comm	34100	2.60%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	4.20%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	4.00%	346,616.08	346,616.08
	05 - Other Generation Plant	Putnam U2	34300	3.30%	380,355.07	380,355.07
	05 - Other Generation Plant	Sanford U4	34300	4.80%	98,339.95	98,339.95
	05 - Other Generation Plant	Sanford U5	34300	4.20%	56,521.05	56,521.05
03 - Continuous Emission Monitoring Total					**10,232,475.17**	**10,232,475.17**
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.10%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					**41,611.58**	**41,611.58**

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Actual Balance December 2011
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	94,329.22	94,329.22
	02 - Steam Generation Plant	Martin U1	31100	2.10%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.60%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.10%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	140,654.89	133,478.89
	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	2.90%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					**11,733,316.29**	**11,726,140.29**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	0.00	47,081.78
	02 - Steam Generation Plant	Martin Comm	31600	2.40%	23,107.32	23,107.32
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	0.00	(38.54)
	02 - Steam Generation Plant	Amortizable	31650	5-Year	86,360.48	86,360.48
	02 - Steam Generation Plant	Amortizable	31670	7-Year	364,984.05	394,958.99
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	0.00	354,919.37
	05 - Other Generation Plant	Amortizable	34650	5-Year	22,458.48	22,458.48
	05 - Other Generation Plant	Amortizable	34670	7-Year	43,232.74	31,180.89
	08 - General Plant		39000	2.10%	0.00	4,412.76
08 - Oil Spill Clean-up/Response Equipment Total					**540,143.07**	**964,441.53**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	0.00
	02 - Steam Generation Plant	Scherer Comm	31100	2.10%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	2.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	2.60%	689.11	689.11
12 - Scherer Discharge Pipline Total					**864,260.42**	**854,323.70**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	Martin U1	31200	2.60%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	2.60%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	665,195.32	437,403.66
20 - Wastewater/Stormwater Discharge Elimination Total					**1,462,862.01**	**1,235,070.35**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	352,942.34	352,942.34
21 - St. Lucie Turtle Nets Total					**352,942.34**	**352,942.34**

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Actual Balance December 2011
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	Cutler Comm	31400	2.20%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	2.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	749,862.61	807,718.60
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	33,272.38	33,272.38
	02 - Steam Generation Plant	Manatee Comm	31500	2.40%	26,325.43	26,325.43
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	45,749.52	45,749.52
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	37,431.45	37,431.45
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	343,785.10	343,785.10
	02 - Steam Generation Plant	Martin Comm	31500	2.40%	34,754.74	34,754.74
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	2,967,754.07	3,333,894.85
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.30%	159,113.30	159,754.32
	02 - Steam Generation Plant	PtEverglades Comm	31500	2.00%	7,782.85	7,782.85
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	850,530.75	850,530.75
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.10%	92,013.09	92,013.09
	02 - Steam Generation Plant	Turkey Pt Comm	31500	2.20%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	1,019,294.68	1,019,614.24
	03 - Nuclear Generation Plant	StLucie U1	32400	1.80%	437,945.38	437,945.38
	03 - Nuclear Generation Plant	StLucie U2	32300	2.40%	552,389.64	552,389.64
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	6.00%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.30%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.20%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2	34300	4.20%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3	34500	3.40%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.50%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34200	3.80%	84,868.00	84,868.00
	05 - Other Generation Plant	PtEverglades GTs	34100	2.20%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	1,836,482.98	1,835,189.50
	05 - Other Generation Plant	PtEverglades GTs	34500	2.10%	7,782.85	7,782.85
	05 - Other Generation Plant	Putnam Comm	34100	2.60%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	2.90%	1,713,191.94	1,730,934.74
	05 - Other Generation Plant	Putnam Comm	34500	2.50%	60,746.93	60,746.93
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	7,065.10
	06 - Transmission Plant - Electric		35200	1.90%	1,042,156.83	1,042,156.83
	06 - Transmission Plant - Electric		35300	2.60%	177,981.88	177,981.88
	06 - Transmission Plant - Electric		35800	1.80%	0.00	65,655.25
	07 - Distribution Plant - Electric		36100	1.90%	2,931,887.67	2,961,658.64
	07 - Distribution Plant - Electric		36670	2.00%	0.00	70,499.45
	08 - General Plant		39000	2.10%	99,812.99	146,691.32
23 - Spill Prevention Clean-Up & Countermeasures Total					**19,346,600.86**	**20,000,811.53**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	16,687,067.37	16,687,067.37
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	15,062,479.29	15,062,479.29
24 - Manatee Reburn Total					**31,749,546.66**	**31,749,546.66**
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31100	1.90%	298,709.93	298,709.93
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	10,404,603.15	10,404,603.15
	02 - Steam Generation Plant	PtEverglades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	PtEverglades U1	31600	2.10%	307,032.30	307,032.30
	02 - Steam Generation Plant	PtEverglades U2	31100	1.90%	184,084.01	184,084.01
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	11,979,735.29	11,979,735.29
	02 - Steam Generation Plant	PtEverglades U2	31500	2.00%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	PtEverglades U2	31600	2.10%	324,086.94	324,086.94
	02 - Steam Generation Plant	PtEverglades U3	31100	1.90%	713,693.44	713,693.44
	02 - Steam Generation Plant	PtEverglades U3	31200	2.30%	18,160,533.65	18,160,533.65
	02 - Steam Generation Plant	PtEverglades U3	31500	2.00%	4,304,056.69	4,304,056.69
	02 - Steam Generation Plant	PtEverglades U3	31600	2.10%	528,541.18	528,541.18
	02 - Steam Generation Plant	PtEverglades U4	31100	1.90%	313,275.79	313,275.79
	02 - Steam Generation Plant	PtEverglades U4	31200	2.30%	20,646,501.29	20,646,501.29
	02 - Steam Generation Plant	PtEverglades U4	31500	2.00%	6,729,950.05	6,729,950.05
	02 - Steam Generation Plant	PtEverglades U4	31600	2.10%	551,535.30	551,535.30
25 - PPE ESP Technology Total					**81,901,169.49**	**81,901,169.49**

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Actual Balance December 2011
26 - UST Remove/Replace						
	08 - General Plant		39000	2.10%	492,916.42	115,446.69
26 - UST Remove/Replace Total					**492,916.42**	**115,446.69**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	102,052.47	102,052.47
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	19,794,254.26	20,059,060.47
	02 - Steam Generation Plant	Manatee U1	31400	2.60%	6,219,701.47	7,168,979.87
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	13,163,149.00	17,191,439.24
	02 - Steam Generation Plant	Manatee U2	31400	2.60%	7,918,302.41	7,918,302.41
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	0.00	518,274.99
	02 - Steam Generation Plant	Martin Comm	31400	2.60%	287,257.77	287,257.77
	02 - Steam Generation Plant	Martin U1	31200	2.60%	14,651,505.23	20,695,251.33
	02 - Steam Generation Plant	Martin U1	31400	2.60%	7,694,692.34	7,794,707.32
	02 - Steam Generation Plant	Martin U2	31200	2.60%	20,683,349.06	19,057,799.99
	02 - Steam Generation Plant	Martin U2	31400	2.60%	7,385,556.36	7,385,556.36
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	28,172,582.67	27,708,298.93
	02 - Steam Generation Plant	SJRPP U1	31500	2.40%	0.00	455,145.91
	02 - Steam Generation Plant	SJRPP U1	31600	2.40%	0.00	9,137.83
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	27,066,114.22	26,630,303.07
	02 - Steam Generation Plant	SJRPP U2	31500	2.40%	0.00	426,219.91
	02 - Steam Generation Plant	SJRPP U2	31600	2.40%	0.00	9,591.24
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.90%	110,241.57	110,241.57
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	57,855.19	57,855.19
	05 - Other Generation Plant	Martin Comm	34100	3.50%	762,997.86	763,350.13
	05 - Other Generation Plant	Martin Comm	34300	4.30%	244,230.62	244,343.38
	05 - Other Generation Plant	Martin Comm	34500	3.40%	292,363.70	292,498.67
	05 - Other Generation Plant	PtEverglades GTs	34300	3.40%	107,874.44	107,874.44
	07 - Distribution Plant - Electric		36500	3.90%	0.00	411,775.23
31 - Clean Air Interstate Rule (CAIR) Total					**154,714,080.64**	**165,405,317.72**
33 - Clean Air Mercury Rule (CAMR)						
	02 - Steam Generation Plant	Scherer U4	31100	2.10%	0.00	67,478.60
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	105,905,052.28	106,777,872.99
	02 - Steam Generation Plant	Scherer U4	31500	2.40%	0.00	33,739.30
33 - Clean Air Mercury Rule (CAMR) Total					**105,905,052.28**	**106,879,090.89**
35 - Martin Drinking Water System						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	235,391.32	235,391.32
35 - Martin Drinking Water System Total					**235,391.32**	**235,391.32**
36 - Low Level Waste Storage (LLW)						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	0.00	6,449,693.36
36 - Low Level Waste Storage (LLW) Total					**0.00**	**6,449,693.36**
37 - DeSoto Solar Energy Center						
	05 - Other Generation Plant	Desoto Solar	34000	0.00%	255,507.00	255,507.00
	05 - Other Generation Plant	Desoto Solar	34100	3.30%	3,249,119.87	4,521,406.52
	05 - Other Generation Plant	Desoto Solar	34300	3.30%	141,636,734.40	115,754,063.29
	05 - Other Generation Plant	Desoto Solar	34500	3.30%	0.00	26,239,255.03
	05 - Other Generation Plant	Amortizable	34630	3-Year	12,102.91	12,102.91
	05 - Other Generation Plant	Amortizable	34650	5-Year	21,934.62	21,934.62
	05 - Other Generation Plant	Amortizable	34670	7-Year	50,094.94	59,592.09
	06 - Transmission Plant - Electric		35200	1.90%	2,603.27	6,543.06
	06 - Transmission Plant - Electric		35300	2.60%	797,283.55	704,626.32
	06 - Transmission Plant - Electric		35310	2.90%	1,712,305.00	1,712,305.00
	06 - Transmission Plant - Electric		35500	3.40%	394,417.57	394,417.57
	06 - Transmission Plant - Electric		35600	3.20%	191,357.87	191,357.87
	07 - Distribution Plant - Electric		36100	1.90%	608,237.66	608,244.37
	07 - Distribution Plant - Electric		36200	2.60%	2,238,948.26	2,214,956.51
	08 - General Plant		39220	9.40%	28,426.16	28,426.16
	08 - General Plant	Amortizable	39720	7-Year	22,344.95	22,114.04
37 - DeSoto Solar Energy Center Total					**151,221,418.03**	**152,746,852.36**

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Actual Balance December 2011
38 - Spacecoast Solar Energy Center						
	01 - Intangible Plant	Amortizable	30300	30-Year	6,359,027.00	6,359,027.00
	05 - Other Generation Plant	Space Coast Solar	34100	3.30%	1,208,355.56	3,838,725.58
	05 - Other Generation Plant	Space Coast Solar	34300	3.30%	60,328,241.78	51,606,083.22
	05 - Other Generation Plant	Space Coast Solar	34500	3.30%	0.00	6,126,698.76
	05 - Other Generation Plant	Amortizable	34630	3-Year	7,271.71	7,271.71
	05 - Other Generation Plant	Amortizable	34650	5-Year	9,438.49	9,438.49
	05 - Other Generation Plant	Amortizable	34670	7-Year	37,454.78	51,560.44
	06 - Transmission Plant - Electric		35300	2.60%	139,390.84	139,390.84
	07 - Distribution Plant - Electric		36100	1.90%	269,763.87	269,805.86
	07 - Distribution Plant - Electric		36200	2.60%	2,186,607.33	2,187,146.99
	08 - General Plant		39220	9.40%	31,858.14	31,858.14
	08 - General Plant	Amortizable	39720	7-Year	6,356.95	6,350.66
38 - Spacecoast Solar Energy Center Total					**70,583,766.45**	**70,633,357.69**
39 - Martin Solar Energy Center						
	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844.31	216,844.31
	05 - Other Generation Plant	Martin Solar	34100	3.30%	90.55	184,125.52
	05 - Other Generation Plant	Martin Solar	34300	3.30%	390,586,865.63	397,293,384.66
	05 - Other Generation Plant	Martin Solar	34500	3.30%	0.00	21,636.52
	05 - Other Generation Plant	Martin Solar	34600	3.30%	1,152.33	1,299.31
	05 - Other Generation Plant	Martin U8	34300	4.30%	300,334.49	379,929.68
	05 - Other Generation Plant	Amortizable	34650	5-Year	21,384.00	21,384.00
	06 - Transmission Plant - Electric		35500	3.40%	618,700.98	603,691.67
	06 - Transmission Plant - Electric		35600	3.20%	368,305.53	364,159.38
	07 - Distribution Plant - Electric		36400	4.10%	9,282.42	9,282.42
	07 - Distribution Plant - Electric		36660	1.50%	0.00	94,476.14
	07 - Distribution Plant - Electric		36760	2.60%	2,728.36	2,728.36
	08 - General Plant		39220	9.40%	0.00	25,193.18
	08 - General Plant		39240	11.10%	0.00	205,307.14
	08 - General Plant		39290	3.50%	0.00	97,633.07
	08 - General Plant	Amortizable	39420	7-Year	0.00	18,992.89
	08 - General Plant	Amortizable	39720	7-Year	0.00	3,203.99
39 - Martin Solar Energy Center Total					**392,125,688.60**	**399,543,272.24**
41 - Manatee Heaters						
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	3,502,299.42	4,043,057.47
	02 - Steam Generation Plant	Riviera Comm	31400	0.60%	2,605,268.34	2,605,268.34
	06 - Transmission Plant - Electric		35300	2.60%	282,951.11	276,404.06
	07 - Distribution Plant - Electric		36100	1.90%	9,669.19	29,779.49
	07 - Distribution Plant - Electric		36200	2.60%	322,202.56	488,424.42
	07 - Distribution Plant - Electric		36400	4.10%	186,148.51	223,459.91
	07 - Distribution Plant - Electric		36500	3.90%	271,244.89	302,616.24
	07 - Distribution Plant - Electric		36660	1.50%	119,589.43	221,325.50
	07 - Distribution Plant - Electric		36760	2.60%	105,249.65	168,995.42
	07 - Distribution Plant - Electric		36910	3.90%	607.49	607.06
	08 - General Plant	Amortizable	39720	7-Year	7,620.86	23,287.46
41 - Manatee Heaters Total					**7,412,851.45**	**8,383,225.37**
42 - Turkey Point Cooling Canal Monitoring						
	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	1.80%	3,593,540.81	3,582,752.89
42 - Turkey Point Cooling Canal Monitoring Total					**3,593,540.81**	**3,582,752.89**
44 - Martin Plant Barley Barber Swamp Iron Mitigation Project						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	0.00	164,704.22
44 - Martin Plant Barley Barber Swamp Iron Mitigation Project Total					**0.00**	**164,704.22**
Grand Total					**1,054,555,260.62**	**1,083,243,264.12**

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

Equity @ 10.00%

CAPITAL STRUCTURE AND COST RATES PER 2009 RATE CASE (a)
Docket No 080677-EI Order No PSC-10-0153-FOF-EI

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	5,298,960,654	31.565%	5.49%	1.73%	1.73%
SHORT TERM DEBT	156,113,805	0.930%	2.11%	0.02%	0.02%
PREFERRED STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER DEPOSITS	544,711,775	3.245%	5.98%	0.19%	0.19%
COMMON EQUITY	7,889,967,199	46.999%	10.00%	4.70%	7.65%
DEFERRED INCOME TAX	2,892,247,084	17.229%	0.00%	0.00%	0.00%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	5,429,401	0.032%	8.19%	0.00%	
			0		
TOTAL	$16,787,429,918	100.00%		6.65%	9.60%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (b)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$5,298,960,654	40.18%	5.49%	2.21%	2.21%
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	7,889,967,199	59.82%	10.00%	5.98%	9.74%
TOTAL	$13,188,927,853	100.00%		8.19%	11.94%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.7329%
SHORT TERM DEBT	0.0196%
CUSTOMER DEPOSITS	0.1940%
TAX CREDITS -WEIGHTED	0.0007%
TOTAL DEBT	**1.9473%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.6999%
TAX CREDITS -WEIGHTED	0.0019%
TOTAL EQUITY	**4.7019%**
TOTAL	6.6492%
PRE-TAX EQUITY	7.6546%
PRE-TAX TOTAL	9.6019%

Note:

(a) Reflects approved capital structure and ROE reflected in Docket 080677-EI which ended in Order No. PSC-10-0153-FOF-EI. The above capital structure started effective March 2010.

(b) This capital structure applies only to Convertible Investment Tax Credit (C-ITC).

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	EXHIBIT	8
PARTY	Florida Power & Light Co.		
DESCRIPTION	R.R. LaBauve (RRL-5A), Supp. CAIR/ CAMR/CAVR Filing		

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 120007-EI
ENVIRONMENTAL COST RECOVERY CLAUSE
FPL SUPPLEMENTAL CAIR/CAMR/CAVR FILING
APRIL 2, 2012

Per Order No. PSC-11-0553-FOF-EI, issued on December 7, 2011, the discussion below provides FPL's current estimates of project activities and associated costs related to its Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR)/ Best Available Retrofit Technology (BART) Projects.

CAIR Compliance Project Update:

Status of CAIR Rule Revision – On July 11, 2008 the United States Circuit Court of Appeals for the District of Columbia (the Court) issued an opinion vacating the United States Environmental Protection Agency's (EPA) CAIR. On December 23, 2008, the Court issued an opinion on rehearing of the July 11 decision and remanded CAIR to the EPA without vacatur, instructing EPA to remedy the CAIR flaws in accordance with the Court's July 11 opinion. This results in CAIR remaining in effect in its current form until it is revised for the July 11 opinion. On July 6, 2010 EPA published a proposed Clean Air Transport Rule (CATR) to replace the CAIR rule that had been remanded to EPA by the Court. EPA subsequently withdrew the proposed CATR and on July 6, 2011 EPA made public its Cross State Air Pollution Rule (CSAPR) as the replacement to CAIR. Interested parties filed petitions for reconsideration with EPA and also filed petitions for judicial review of CSAPR. FPL joined the Florida Coordinating Group in its petition to EPA for reconsideration of several issues through which the affected Florida generating units would receive additional emission allowances under CSAPR. On December 30, 2011 the DC Circuit Court of Appeals issued a stay on the rule and set an abbreviated schedule for submittal of briefs and oral argument to assess the merits of a stay and remand of the rule to EPA. All parties have filed briefs and oral argument is set for April 2012. In the Court's decision to stay the rule, the CAIR requirements are now in effect for all affected states. FPL anticipates that the court's decision could come early this summer but we cannot know the outcome of their decision. In accordance with the December 23, 2008 Court decision, CAIR remains in effect until a replacement rule is finalized by EPA.

St. Johns River Power Park (SJRPP) Selective Catalytic Reduction Systems (SCR) and Ammonia Injection Systems – The construction and installation of SCR and Ammonia Injection Systems on SJRPP was accomplished in 2009 with the controls on both units being placed into service in 2010. The total CAIR capital cost for installation of the SCR and Ammonia Injection System for FPL's ownership share of SJRPP is $55.3 million.

Estimated CAIR O&M expenses for 2012 are $0.6 million and estimated annual O&M expenses beginning 2013 are approximately $0.6 million (FPL 20% ownership). Ongoing

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O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment.

Scherer SCR and Wet Flue Gas Desulfurization (FGD) - Current capital cost estimates for FPL's share of the installation of the FGD, Scrubber and SCR with Ammonia Injection System on Scherer Unit 4 is $363.9 million. The planned construction activities in 2012 include the installation of instrumentation for the FGD and SCR controls on Unit 4, by-product and reagent facility common storage, and final tie-in of controls during the spring planned outage.

Unit specific engineering and design work on the FGD and SCR for Unit 4 was completed in 2008 and procurement of materials needed for the construction of the equipment began in 2009. Foundation work for the FGD and SCR and for the new chimney at the output from the FGD was completed in 2008. Project work accomplished in 2009 included: delivery and initial installation of SCR structural steel; delivery and installation of SCR ammonia storage facility; initial construction of FGD chimney liner and absorber foundation activities; Scherer common FGD facility work including limestone handling prep equipment, tanks, piping, and electrical; and initial construction activities for FGD gypsum waste disposal facility. The 2010 project work included the erection of the scrubber vessel and stack/liner. Unanticipated, persistent inclement weather increased the original planned construction schedule. Project work in 2010 also included the SCR support structure and Unit 4 FGD absorber vessel. Additionally, construction was substantially completed in 2010 for SCR and FGD project common facilities (e.g., unloading and storage facilities for ammonia and limestone and limestone grinding facilities). Construction activities completed in 2011 included the completion of FGD absorber fill, recycle pump alignments, SCR damper completion, SCR ash system, and CEMS sample lines. FPL estimates its share of the Scherer Unit 4 CAIR capital costs to be $29.7 million in 2012 and $7.4 million in 2013. FPL has preliminarily estimated annual O&M for operation of the SCR, FGD, and common plant facilities supporting the controls at $3.4 million for 2012 when the FGD and SCR are projected to be in-service and $5.6 million in 2013 for the first full year of controls operation. O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment. O&M activities for the FGD include limestone consumption, limestone and by-product handling operation, FGD operations, FGD tower and auxiliary equipment maintenance.

800 MW unit cycling project –FPL witness Randall R. LaBauve introduced this project in his September 1, 2006 testimony and subsequently provided an estimate for implementation of the projects with a total capital cost of $104.8 million. FPL had originally planned completion of the 800 MW unit cycling project in 2010 at the Martin and Manatee Plants utilizing existing planned outage windows to complete project work. As a result of changes to the Manatee Unit 2 outage schedule to accommodate system load requirements, completion of remaining boiler and associated drain work was accomplished in 2011.

Total capital costs for the 800 MW unit cycling project are $115.2 million and total O&M expenses to date are $4.1 million. Completed work in 2011 included the Super Heat (SH) Spray Upgrade, Extraction Control/Mass Blowdown on Manatee Unit 2, the implementation

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of rotor stress monitors on all four 800 MW units, and the remaining boiler work at Manatee Unit 2. Projected O&M expenses for 2012 are $0.540 million and 0.549 million in 2013 for treatment of condenser tube fouling.

Continuous Emissions Monitoring System (CEMS) Plan for Gas Turbines (GT) - The Low Mass Emitting (LME) CEMS under 40 CFR Part 75 have been installed, tested, and are now in operation at the Fort Myers, Port Everglades, and Fort Lauderdale Gas Turbine Parks, as required by the CAIR and by the CSAPR.

FPL has projected O&M expenses of $5,000 per year that will be required for routine maintenance of these CEMS systems. It should be noted that the LME option is available for a GT only if its emissions remain under EPA-prescribed thresholds. If any GT emits more than 50 tons of NOx or 25 tons of SO2 in a given calendar year, the testing for that GT will be required every year, instead of every five years. That would increase the testing costs for non-qualifying GTs to $65,000 per year, along with $5,000 per year for maintenance. FPL has not projected operation of any GT to exceed the LME limits.

Purchases of allowances – To comply with the CAIR Ozone Season NOx program requirements, FPL purchased CAIR allowances that were needed for compliance at a total cost of $98,325 for compliance year 2009. The 855 CAIR Ozone season allowances, in addition to the 12,418 allowances allocated to FPL by the EPA, were needed to comply with CAIR requirements for fossil generating unit emissions during the May through September 2009 Ozone Season. As a result of the lower than previously projected system load, and changes in FPL's generation plan mentioned above, FPL had sufficient allowances for compliance with the 2010 and 2011 CAIR NOx Ozone Season and had sufficient allowances for compliance with the CAIR 2010 and 2011 NOx Annual programs without purchasing additional allowances. Future purchases of allowances will be made as needed for compliance with the annual and ozone season NOx requirements under CAIR and the CSAPR. While FPL has received allocations to its existing CAIR fossil generating units, FPL has projected, but does not know precisely, the number of allowances it will be allocated under the CAIR NOx Annual and Ozone Season new source set-aside program for the West County Energy Center generating units.

FPL has evaluated the proposed allowance allocations under CSAPR and has projected that it will have sufficient allocated allowances to cover projected emissions in 2012 and 2013 and has not projected a need to purchase allowances under CSAPR or CAIR.

Actual CAIR capital costs through 2011 were $949.0 million.

CAIR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	0.0	0.0	55.3
Scherer-SCR/FGD	29.7	7.4	363.9
800 MW Unit Cycling - Martin	0.0	0.0	58.3
800 MW Unit Cycling - Manatee	0.0	0.0	56.9
CEMS at GTs	Capital project completed	Capital project completed	Capital project completed
Allowances	N/A	N/A	N/A

Actual CAIR O&M expenses through 2011 are $6.6 million.

CAIR O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	0.6	0.6	0.6 (2012+ annual operating costs are on-going)
Scherer-SCR/FGD	3.4	5.6	3.4 (2012+ annual operating costs are on-going)
800 MW Unit Cycling – Martin	0.300	0.300	0.305 (2012+ annual operating costs are on-going
800 MW Unit Cycling – Manatee	0.240	0.249	0.249 (2012+ annual operating costs are on-going
CEMS at GTs	0.005	0.005	0.005 (2012+ annual operating costs are on-going)
Allowances	0	0	N/A

CAMR Compliance Project Update:

On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury (Hg) emissions from coal-fired power plants for the first time. In response to the EPA CAMR, the Georgia Environmental Protection Division (EPD) promulgated two major rules to implement Hg reductions within Georgia: a rule to adopt the CAMR federal Hg cap and trade program: Rule 391-3-1-.02(15) – "*Georgia Mercury Trading Rule*" and a Georgia state specific Multipollutant Rule: Rule 391-3-1-.02(2)(sss) – " *Multipollutant Control for Electric Utility Steam Generating Units*" which became effective June 1, 2008. The Multipollutant Rule was promulgated to specify the implementation of specific air pollution control equipment for reductions in Hg, sulfur dioxide (SO2), and nitrogen oxides (NOx) emissions from identified coal-fired Electric Generating Units (EGUs) within Georgia. Section 4(i) of the Multipollutant Rule requires that Scherer Unit 4 may not be operated after April 30, 2010, unless it is equipped and operated with sorbent injection and a baghouse for the control of Hg emissions.

Installation of the Hg controls, and associated continuous Hg emission monitoring that would have been needed to comply with the CAMR requirements remain necessary to comply with the requirements of the Georgia Multipollutant Rule; therefore installation of Hg controls on Plant Scherer Unit 4 must continue. The vacatur of CAMR does not change the compliance obligations at Plant Scherer, including FPL's share of Unit 4. In addition, on December 16, 2011 EPA published its final Mercury and Air Toxics Standards (MATS) Rule as a replacement for CAMR. EPA's MATS Rule sets limits on emissions of Toxic Metal Hazardous Air Pollutants (HAPs), including Hg, limits on emissions of acid gasses, and work practice standards for emissions of Organic HAPs. FPL has reviewed the compliance requirements of the MATS rule and believes that controls installed on Scherer Unit 4 for compliance with CAIR, CAMR, and the Georgia Multi-Pollutant Rule, will allow the unit to meet the rule's emission specifications for Hazardous Air Pollutants. Specifically, FPL is complying with the Hg reduction requirements of the Georgia Multipollutant Rule and EPA's MATS Rule by using the following projects identified previously under CAMR:

1. Installation of Fabric Filter Baghouse and Mercury Sorbent Injection System on Scherer Unit 4 (completed 2010).
2. Installation of HgCEMS on Scherer Unit 4 (completed 2009).
3. Installation of HgCEMS on SJRPP Units 1 & 2 (completed in 2008 prior to the vacatur of CAMR). Hg CEMS are required to comply with MATS Rule.

Total capital costs to date for the CAMR project are $107.3million. Projected annual O&M associated with operation of the Hg controls includes purchase of new sorbent, disposal of spent sorbent, replacement of filter bags, and maintenance activities associated with the baghouse and sorbent injection system, and the maintenance costs associated with FPL's share of the Scherer Unit 4 Hg CEMS. Projected CAMR capital expenses for plant Scherer are $0.133 million for 2012 and $0.111 million for 2013 for anticipated capital equipment component replacements. Projected CAMR O&M expenses for plant Scherer are $3.3 million for 2012 and $4.2 million for 2013 primarily for purchase and disposal of sorbents and replacement of bags.

FPL's cost associated with the installation of Hg CEMS at SJRPP represented a total capital cost of $0.4 million. FPL does not yet know whether SJRPP will meet all applicable emission specifications of the MATS rule. FPL and JEA have recently initiated a study of the potential impacts of MATS and other proposed rules on the SJRPP units to develop the appropriate compliance strategy.

Actual CAMR capital costs through 2011 are $107.3million.

CAMR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT**
SJRPP-Mercury CEMS	0.0	0.0	0.40
Scherer-Sorbent Injection/Baghouse/ Mercury CEMS	0.133	0.111	106.9

Actual CAMR O&M expenses through 2011 are $3.5 million.

CAMR O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT**
SJRPP-Mercury CEMS	0	0	0.0
Scherer-Sorbent Injection/Baghouse/ HgCEMS	3.31	4.15	(2012+ annual operating costs are on-going)

CAVR / BART Project Update:

FPL successfully concluded negotiations with the Florida Department of Environmental Protection (FDEP or the Department) regarding Turkey Point Units 1 & 2 in February 2009, with the Department accepting FPL's proposed plan to comply with the BART requirements under the Regional Haze program. In 2011 FPL negotiated with FDEP changes to its compliance plan at Turkey Point to address changes to the state's plan as a result of the CSAPR impact on the regional haze State Implementation Plan (SIP). FPL proposed to remove the requirement to install new multi-cyclone dust collectors and instead proposed to reduce emissions of SO2 through use of 0.7% Sulfur residual fuel oil and to commit to no longer burning fossil fuels in the Unit 2 boiler and to take a significant reduction in fuel oil firing in Unit 1 boiler beginning in 2013. FPL projects that there will be no associated capital costs or increased O&M for compliance with the BART permit at Turkey Point. In 2011 FDEP identified that there were concerns with the analysis of the Putnam units which they were projecting exceedances of the criteria. FPL retained a consultant in 2012 to prepare

modeling required by the state to demonstrate that the Putnam plant does not exceed the criteria thresholds. FPL will recover those costs through the CAVR ECRC project.

EPA has told FDEP that it will not approve Florida's Draft CAVR SIP, primarily due to the FDEP Reasonable Progress Control Technology (RPCT) Rule which uses a permit application process that EPA finds unacceptable. FDEP has indicated that it will withdraw the RPCT Rule from the Florida Administrative Code (FAC) and delete the RPCT provision from the SIP. FDEP contends that visibility improvements at Florida's Class 1 Areas will meet the Reasonable Progress glide slope in 2018 by way of existing air rules promulgated previously. At this time, FDEP has determined that no additional rulemaking will be needed. Until EPA rules on the FDEP CAVR SIP, FPL cannot know if controls will be required beyond 2018.

When EPA issued its CSAPR, Florida was no longer included in the particulate matter portion of the rule removing previously affected units from the annual NOx and SO2 requirements. Because of the regulatory uncertainty from the status of CSAPR and CAIR, FPL must undergo a full 5-factor BART Determination for SO2 and NOx. Turkey Point Units 1&2, Manatee Units 1&2, and Martin Units 1&2 are affected by this change. Consultant costs for BART Determinations for these facilities are estimated to be $30,000.

Actual CAVR capital costs through 2011 are $0.

Actual CAVR O&M expenses through 2011 are $0.041 million. FPL has projected a preliminary estimated O&M total cost of $0.030 million in 2012 for the required modeling of the Putnam facility.

CAVR/BART O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT***
Reasonable Process Control Technology	.030	0	0.071

* *Through 2012*

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-9E

JANUARY 2012 - DECEMBER 2012
ACTUAL/ESTIMATED TRUE-UP

TJK-2
DOCKET NO. 120007-EI
EXHIBIT_____
PAGES 1-72

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 9
PARTY Florida Power & Light Co.
DESCRIPTION T.J. Keith (TJK-2) Appendix I, Enviromental
True up 1/-12/12, Forms 42-1E - 42-9E

Form 42-1E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up
for the period January 2012 through December 2012

Line No.			
1	Over/(Under) Recovery for the Current Period (Form 42-2E Page 2 of 2, Line 5)	$	(397)
2	Interest Provision (Form 42-2E Page 2 of 2, Line 6)	$	8,018
3	Sum of Current Period Adjustments (Form 42-2E, Page 2 of 2, Line 10)	$	-
4	Actual/Estimated True-up to be refunded/(recovered) in January 2013 through December 2013	$	7,620

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up Amount for the Period
January 2012 through December 2012

Line No.		ACTUAL January	ACTUAL February	ACTUAL March	ACTUAL April	ACTUAL May	ACTUAL June
1	ECRC Revenues (net of Revenue Taxes)	$13,222,460	$11,667,373	$12,547,706	$13,594,989	$13,868,057	$16,281,152
2	True-up Provision (Order No. PSC-11-0553-FOF-EI)	1,145,425	1,145,425	1,145,425	1,145,425	1,145,425	1,145,425
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	14,367,885	12,812,798	13,693,131	14,740,414	15,013,482	17,426,577
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5E, Line 9)	2,043,067	1,417,788	1,475,729	2,029,427	1,978,052	2,069,485
	b - Capital Investment Projects (Form 42-7E, Line 9)	12,824,620	12,993,914	13,029,463	13,040,002	13,065,653	13,269,899
	c - Total Jurisdictional ECRC Costs	14,867,687	14,411,702	14,505,191	15,069,429	15,043,705	15,339,384
5	Over/(Under) Recovery (Line 3 - Line 4c)	(499,802)	(1,598,904)	(812,060)	(329,015)	(30,223)	2,087,193
6	Interest Provision (Form 42-3E, Line 10)	869	1,121	780	669	658	594
7	Prior Periods True-Up to be (Collected)/Refunded in 2011	13,745,099	12,100,740	9,357,533	7,400,828	5,927,057	4,752,067
	a - Deferred True-Up from 2011 (Form 42-1A, Line 7) Final True-up filed April 1, 2012	976,912	976,912	976,912	976,912	976,912	976,912
8	True-Up Collected /(Refunded) (See Line 2)	(1,145,425)	(1,145,425)	(1,145,425)	(1,145,425)	(1,145,425)	(1,145,425)
9	End of Period True-Up (Lines 5+6+7+7a+8)	13,077,652	10,334,445	8,377,740	6,903,969	5,728,979	6,671,341
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$13,077,652	$10,334,445	$8,377,740	$6,903,969	$5,728,979	$6,671,341

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up Amount for the Period
January 2012 through December 2012

Line No.		ESTIMATED July	ESTIMATED August	ESTIMATED September	ESTIMATED October	ESTIMATED November	ESTIMATED December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$16,878,102	$16,811,288	$16,160,531	$15,127,976	$13,557,576	$13,288,310	$173,005,520
2	True-up Provision (Order No. PSC-11-0553-FOF-EI)	1,145,425	1,145,425	1,145,425	1,145,425	1,145,425	1,145,425	13,745,099
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	18,023,527	17,956,713	17,305,956	16,273,401	14,703,001	14,433,735	186,750,619
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5E, Line 9)	2,523,403	1,978,187	2,075,633	2,235,653	2,292,878	2,343,093	24,462,397
	b - Capital Investment Projects (Form 42-7E, Line 9)	13,515,627	13,816,212	14,093,335	14,175,210	14,203,232	14,261,454	162,288,620
	c - Total Jurisdictional ECRC Costs	16,039,030	15,794,398	16,168,968	16,410,863	16,496,110	16,604,547	186,751,017
5	Over/(Under) Recovery (Line 3 - Line 4c)	1,984,497	2,162,315	1,136,988	(137,462)	(1,793,109)	(2,170,812)	(397)
6	Interest Provision (Form 42-3E, Line 10)	591	668	710	657	481	220	8,018
7	Prior Periods True-Up to be (Collected)/Refunded in 2011	5,694,429	6,534,093	7,551,651	7,543,924	6,261,694	3,323,641	13,745,099
	a - Deferred True-Up from 2011 (Form 42-1A, Line 7) Final True-up filed April 1, 2012	976,912	976,912	976,912	976,912	976,912	976,912	
8	True-Up Collected /(Refunded) (See Line 2)	(1,145,425)	(1,145,425)	(1,145,425)	(1,145,425)	(1,145,425)	(1,145,425)	(13,745,099)
9	End of Period True-Up (Lines 5+6+7+7a+8)	7,511,005	8,528,563	8,520,835	7,238,606	4,300,553	984,536	7,620
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$7,511,005	$8,528,563	$8,520,835	$7,238,606	$4,300,553	$984,536	$7,620

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up Amount for the Period
January 2012 through December 2012

Interest Provision (In Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$14,722,011	$13,077,652	$10,334,445	$8,377,740	$6,903,969	$5,728,979
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	13,076,784	10,333,324	8,376,960	6,903,300	5,728,321	6,670,747
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$27,798,795	$23,410,976	$18,711,405	$15,281,040	$12,632,290	$12,399,727
4	Average True-Up Amount (Line 3 x 1/2)	$13,899,397	$11,705,488	$9,355,702	$7,640,520	$6,316,145	$6,199,863
5	Interest Rate (First Day of Reporting Month)	0.03000%	0.12000%	0.11000%	0.09000%	0.12000%	0.13000%
6	Interest Rate (First Day of Subsequent Month)	0.12000%	0.11000%	0.09000%	0.12000%	0.13000%	0.10000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.15000%	0.23000%	0.20000%	0.21000%	0.25000%	0.23000%
8	Average Interest Rate (Line 7 x 1/2)	0.07500%	0.11500%	0.10000%	0.10500%	0.12500%	0.11500%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.00625%	0.00958%	0.00833%	0.00875%	0.01042%	0.00958%
10	Interest Provision for the Month (Line 4 x Line 9)	$869	$1,121	$780	$669	$658	$594

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up Amount for the Period
January 2012 through December 2012

Interest Provision (in Dollars)

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$6,671,341	$7,511,005	$8,528,563	$8,520,835	$7,238,606	$4,300,553	N/A
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	7,510,414	8,527,895	8,520,125	7,237,949	4,300,072	984,316	N/A
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$14,181,755	$16,038,899	$17,048,688	$15,758,784	$11,538,678	$5,284,870	N/A
4	Average True-Up Amount (Line 3 x 1/2)	$7,090,878	$8,019,450	$8,524,344	$7,879,392	$5,769,339	$2,642,435	N/A
5	Interest Rate (First Day of Reporting Month)	0.10000%	0.10000%	0.10000%	0.10000%	0.10000%	0.10000%	N/A
6	Interest Rate (First Day of Subsequent Month)	0.10000%	0.10000%	0.10000%	0.10000%	0.10000%	0.10000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.20000%	0.20000%	0.20000%	0.20000%	0.20000%	0.20000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	0.10000%	0.10000%	0.10000%	0.10000%	0.10000%	0.10000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.00833%	0.00833%	0.00833%	0.00833%	0.00833%	0.00833%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$591	$668	$710	$657	$481	$220	$8,018

Form 42-4E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-Up Amount for the Period
January 2012 - December 2012

Variance Report of O&M Activities
(in Dollars)

Line		(1) Actual Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
1	Air Operating Permit Fees	$506,168	$1,290,000	($783,832)	-60.8%
3a	Continuous Emission Monitoring Systems	$606,214	$754,456	($148,242)	-19.6%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,726,273	$2,192,743	($466,470)	-21.3%
8a	Oil Spill Cleanup/Response Equipment	$403,061	$212,600	$190,461	89.6%
13	RCRA Corrective Action	$24,000	$100,000	($76,000)	-76.0%
14	NPDES Permit Fees	$74,325	$115,200	($40,875)	-35.5%
17a	Disposal of Noncontainerized Liquid Waste	$161,252	$221,000	($59,748)	-27.0%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution	$1,550,490	$2,819,714	($1,269,224)	-45.0%
19b	Substation Pollutant Discharge Prevention & Removal-Transmission	$962,338	$985,429	($23,091)	-2.3%
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($560,232)	($560,232)	$0	0.0%
NA	Amortization of Gains on Sales of Emissions Allowances	($598,910)	($603,113)	$4,202	-0.7%
22	Pipeline Integrity Management	$429,792	$476,500	($46,708)	-9.8%
23	SPCC-Spill Prevention, Control & Countermeasures	$1,133,775	$953,190	$180,585	18.9%
24	Manatee Reburn	$1,158,659	$900,000	$258,659	28.7%
25	Port Everglades ESP	$331,251	$640,000	($308,749)	-48.2%
27	Lowest Quality Water Source	$322,942	$329,710	($6,768)	-2.1%
28	CWA 316(b) Phase II Rule	$72,018	$1,183,091	($1,111,073)	-93.9%
29	SCR Consumables	$494,143	$350,000	$144,143	41.2%
30	HBMP	$35,653	$35,652	$1	0.0%
31	CAIR Compliance	$3,531,009	$4,652,000	($1,120,991)	-24.1%
32	BART Compliance	$15,900	$0	$15,900	NA
33	MATS Project	$3,339,903	$3,291,000	$48,903	1.5%
34	St. Lucie Cooling Water System Inspection & Maintenance	($0)	$0	($0)	NA
35	Martin Plant Drinking Water System Compliance	$20,001	$20,000	$1	0.0%
36	Low-Level Radioactive Waste Storage	$0	$0	$0	NA
37	DeSoto Next Generation Solar Energy Center	$981,097	$1,108,836	($127,739)	-11.5%
38	Space Coast Next Generatino Solar Energy Center	$291,520	$597,856	($306,336)	-51.2%
39	Martin Next Generation Solar Energy Center	$3,539,059	$2,479,444	$1,059,615	42.7%
40	Greenhouse Gas Reduction Program	$1,500	$60,000	($58,500)	-97.5%
41	Manatee Temporary Heating System Project	$629,999	$1,335,073	($705,074)	-52.8%
42	Turkey Point Cooling Canal Monitoring Plan	$2,565,000	$1,320,000	$1,245,000	94.3%
43	NESHAP Information Collection Request Project	$0	$0	$0	NA
44	Martin Plant Barley Barber Swamp Iron Mitigation Project	$100	$2,250	($2,150)	-95.6%
45	800 MW Unit ESP Project	$433,504	$0	$433,504	NA
46	St. Lucie Cooling Water Discharge Monitoring Project	$421,990	$998,185	($576,195)	-57.7%
47	NPDES Permit Renewal Requirements	$100,676	$73,600	$27,076	36.8%
48	Industrial Boiler MACT Project	$1,000	$41,453	($40,453)	-97.6%
49	Thermal Discharge Standards	$175,000	$0	$175,000	NA
50	Steam Electric Effluent Guidelines Revised Rule Project	$5,000	$0	$5,000	NA
51	Gopher Tortoise Relocations	$37,500	$0	$37,500	NA
2	Total O&M Activities	$24,922,971	$28,375,637	($3,452,666)	-12.2%
3	Recoverable Costs Allocated to Energy	$13,631,132	$14,477,271	($846,139)	-5.8%
4a	Recoverable Costs Allocated to CP Demand	$10,021,465	$11,358,768	($1,337,304)	-11.8%
4b	Recoverable Costs Allocated to GCP Demand	$1,270,374	$2,539,598	($1,269,224)	-50.0%

Notes:
Column(1) is the 12-Month Totals on Form 42-5E
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual / Estimated Amount for the Period
January 2012 - December 2012

O&M Activities
(in Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of O&M Activities							
	1 Air Operating Permit Fees	$ 67,322	$ (10,997)	$ 64,001	$ 64,001	$ 63,999	$ 5,921	$ 254,247
	3a Continuous Emission Monitoring Systems	131,595	7,889	36,178	40,342	24,062	37,871	279,737
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks	336	(803)	200,601	196,834	603,605	241,999	1,242,572
	8a Oil Spill Cleanup/Response Equipment	8,358	10,563	15,222	14,687	13,113	14,772	76,914
	13 RCRA Corrective Action	0	0	0	0	0	0	0
	14 NPDES Permit Fees	101,800	(15,262)	2,319	(5,342)	(375)	(8,636)	74,484
	17a Disposal of Noncontainerized Liquid Waste	818	285	825	123	0	0	2,051
	19a Substation Pollutant Discharge Prevention & Removal - Distribution	58,824	204,124	77,949	66,522	197,900	89,171	694,490
	19b Substation Pollutant Discharge Prevention & Removal - Transmission	(57,709)	109,084	52,676	142,329	259,885	53,077	559,342
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
	NA Amortization of Gains on Sales of Emissions Allowances	(49,790)	(49,790)	(49,790)	(50,223)	(49,953)	(49,909)	(299,455)
	22 Pipeline Integrity Management	44,959	0	16,000	52,906	823	6,578	131,267
	23 SPCC - Spill Prevention, Control & Countermeasures	46,506	103,254	130,464	337,980	(246,182)	141,058	513,180
	24 Manatee Reburn	206,824	19,375	76,819	123,400	75,841	36,721	538,979
	25 Pt. Everglades ESP Technology	30,753	32,216	14,028	20,474	19,161	26,982	143,633
	27 Lowest Quality Water Source	26,392	25,769	25,784	24,673	25,202	25,500	153,320
	28 CWA 316(b) Phase II Rule	2,005	2,006	51,968	2,330	2,382	5,326	66,019
	29 SCR Consumables	79,045	72,868	70,689	55,881	47,278	35,791	361,551
	30 HBMP	5,645	1,802	1,802	1,802	1,802	3,083	15,934
	31 CAIR Compliance	145,959	99,280	94,126	100,484	131,311	131,305	702,466
	32 BART Compliance	0	0	0	0	0	6,468	6,468
	33 MATS Project	311,355	344,830	80,220	266,169	364,289	785,984	2,152,847
	34 St. Lucie Cooling Water System Inspection & Maintenance	(4,693)	17,573	(1,959)	592	(19,148)	(641)	(8,275)
	35 Martin Plant Drinking Water System Compliance	1,839	0	1,839	1,839	1,839	1,839	9,195
	36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
	37 DeSoto Next Generation Solar Energy Center	75,868	59,302	78,589	62,773	65,161	62,997	404,489
	38 Space Coast Next Generation Solar Energy Center	14,119	16,450	29,618	14,092	13,872	8,799	96,949
	39 Martin Next Generation Solar Energy Center	396,001	246,955	240,185	223,998	370,538	399,643	1,877,320
	40 Greenhouse Gas Reduction Program	1,500	0	0	0	0	0	1,500
	41 Manatee Temporary Heating System Project	69,586	64,200	14,924	2,263	32,869	14,348	228,190
	42 Turkey Point Cooling Canal Monitoring Plan	381,038	95,158	165,270	324,391	17,804	31,653	1,015,314
	43 NESHAP Information Collection Request Project	0	0	0	0	0	0	0
	44 Martin Plant Barley Barber Swamp Iron Mitigation Project	0	0	0	0	0	0	0
	45 800 MW Unit ESP Project	0	0	0	0	0	0	0
	46 St. Lucie Cooling Water Discharge Monitoring Project	33,329	0	41,140	6,896	29,015	39,718	150,098
	47 NPDES Permit Renewal Requirements	0	3,130	17,322	13,277	14,651	8,611	56,991
	48 Industrial Boiler MACT Project	0	0	0	0	0	0	0
	49 Thermal Discharge Standards	0	0	0	0	0	0	0
	50 Steam Electric Effluent Guidelines Revised Rule Project	0	0	0	0	0	0	0
	51 Gopher Tortoise Relocations	0	0	0	0	0	0	0
2	Total of O&M Activities	$ 2,082,800	$ 1,442,358	$ 1,504,122	$ 2,069,008	$ 2,014,076	$ 2,109,345	$ 11,221,704
3	Recoverable Costs Allocated to Energy	$ 1,378,126	$ 722,273	$ 586,769	$ 971,343	$ 757,990	$ 1,080,193	$ 5,496,696
4a	Recoverable Costs Allocated to CP Demand	$ 669,190	$ 539,303	$ 862,747	$ 1,054,484	$ 1,081,529	$ 963,322	$ 5,170,576
4b	Recoverable Costs Allocated to GCP Demand	$ 35,481	$ 180,781	$ 54,606	$ 43,179	$ 174,557	$ 65,828	$ 554,432
5	Retail Energy Jurisdictional Factor	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	
6a	Retail CP Demand Jurisdictional Factor	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 1,351,685	$ 708,415	$ 575,511	$ 952,708	$ 743,446	$ 1,059,487	$ 5,391,230
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 655,900	$ 528,592	$ 845,613	$ 1,033,541	$ 1,060,049	$ 944,190	$ 5,067,886
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 35,481	$ 180,781	$ 54,606	$ 43,179	$ 174,557	$ 65,828	$ 554,432
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 2,043,067	$ 1,417,788	$ 1,475,729	$ 2,029,427	$ 1,978,052	$ 2,069,485	$ 11,013,548

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual / Estimated Amount for the Period
January 2012 - December 2012

O&M Activities
(In Dollars)

Line #	Project #	Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification: CP Demand	GCP Demand	Energy
1	Description of O&M Activities											
	1 Air Operating Permit Fees	$ 40,577	$ 42,249	$ 42,249	$ 42,249	$ 42,248	$ 42,349	$ 251,921	$ 506,168			$ 506,168
	3a Continuous Emission Monitoring Systems	129,194	26,846	33,773	25,335	29,702	81,828	326,477	606,214			606,214
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks	351,400	200	200	70,200	60,200	1,501	483,701	1,726,273	1,726,273		
	8a Oil Spill Cleanup/Response Equipment	49,100	99,100	93,100	61,003	18,850	8,994	326,147	403,081			403,081
	13 RCRA Corrective Action	0	0	0	8,000	8,000	8,000	24,000	24,000	24,000		
	14 NPDES Permit Fees	(158)	0	0	0	0	0	(158)	74,325	74,325		
	17a Disposal of Noncontainerized Liquid Waste	0	36,000	33,201	30,000	60,000	0	159,201	161,252			161,252
	19a Substation Pollutant Discharge Prevention & Removal - Distribution	108,500	108,500	118,500	188,500	168,500	183,500	856,000	1,550,490		1,550,490	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission	54,666	54,666	54,668	74,666	89,666	74,666	402,998	962,338	888,312		74,026
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(48,666)	(48,666)	(48,666)	(48,666)	(48,666)	(48,666)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
	NA Amortization of Gains on Sales of Emissions Allowances	(49,909)	(49,909)	(49,909)	(49,909)	(49,909)	(49,909)	(299,455)	(598,910)			(598,910)
	22 Pipeline Integrity Management	25,000	9,826	122,000	141,866	0	0	298,526	429,792	429,792		
	23 SPCC - Spill Prevention, Control & Countermeasures	242,411	64,425	64,725	71,501	77,841	89,682	620,585	1,133,775	1,133,775		
	24 Manatee Reburn	61,614	41,667	35,000	41,667	250,251	189,481	619,680	1,158,659			1,158,659
	25 Pt. Everglades ESP Technology	22,855	32,469	32,468	32,468	32,378	34,981	187,617	331,251			331,251
	27 Lowest Quality Water Source	29,453	27,476	27,476	27,476	27,476	30,265	169,622	322,942	322,942		
	28 CWA 316(b) Phase II Rule	1,000	1,000	1,000	1,000	1,000	1,000	6,000	72,018	72,018		
	29 SCR Consumables	22,997	22,997	22,997	22,997	22,997	17,607	132,592	494,143			494,143
	30 HBMP	4,534	2,297	2,297	2,971	4,849	2,971	19,718	35,653	35,653		
	31 CAIR Compliance	462,805	462,980	462,980	462,980	462,256	434,802	2,828,543	3,531,009			3,531,009
	32 BART Compliance	0	4,532	0	4,900	0	0	9,432	15,900			15,900
	33 MATS Project	280,658	175,396	175,750	175,750	175,750	203,751	1,187,056	3,339,903			3,339,903
	34 St. Lucie Cooling Water System Inspection & Maintenance	8,276	0	0	0	0	0	8,276	(0)	(0)		
	35 Martin Plant Drinking Water System Compliance	1,805	1,800	1,800	1,800	1,800	1,800	10,805	20,001	20,001		
	36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0	0	0		0
	37 DeSoto Next Generation Solar Energy Center	113,410	98,275	112,475	61,742	86,842	83,863	576,607	981,097	981,097		
	38 Space Coast Next Generation Solar Energy Center	26,941	35,191	38,141	27,021	25,941	43,335	194,570	291,520	291,520		
	39 Martin Next Generation Solar Energy Center	336,104	261,104	261,104	261,104	261,104	261,218	1,661,738	3,539,059	3,539,059		
	40 Greenhouse Gas Reduction Program	0	0	0	0	0	0	0	1,500			1,500
	41 Manatee Temporary Heating System Project	5,752	1,060	40,395	89,976	106,804	157,622	401,609	629,999			629,999
	42 Turkey Point Cooling Canal Monitoring Plan	258,280	258,280	258,280	258,280	258,280	258,268	1,549,886	2,565,000			2,565,000
	43 NESHAP Information Collection Request Project	0	0	0	0	0	0	0	0			0
	44 Martin Plant Barley Barber Swamp Iron Mitigation Project	0	0	0	0	0	100	100	100	100		
	45 800 MW Unit ESP Project	0	86,701	86,701	86,701	86,701	86,700	433,504	433,504			433,504
	46 St. Lucie Cooling Water Discharge Monitoring Project	11,334	86,854	9,715	45,473	9,715	96,801	271,892	421,990	421,990		
	47 NPDES Permit Renewal Requirements	0	7,400	0	6,285	20,000	10,000	43,685	100,676	100,676		
	48 Industrial Boiler MACT Project	0	1,000	0	0	0	0	1,000	1,000	1,000		
	49 Thermal Discharge Standards	0	25,000	25,000	50,000	25,000	50,000	175,000	175,000	175,000		
	50 Steam Electric Effluent Guidelines Revised Rule Project	0	5,000	0	0	0	0	5,000	5,000	5,000		
	51 Gopher Tortoise Relocations	0	0	37,500	0	0	0	37,500	37,500	37,500		
2	Total of O&M Activities	$ 2,571,912	$ 2,015,678	$ 2,114,878	$ 2,277,128	$ 2,335,354	$ 2,386,317	$ 13,701,267	$ 24,922,971	$ 10,021,465	$ 1,270,374	$ 13,631,132
3	Recoverable Costs Allocated to Energy	$ 1,306,333	$ 1,262,757	$ 1,286,374	$ 1,288,325	$ 1,519,406	$ 1,468,239	$ 8,134,436	$ 13,631,132			
4a	Recoverable Costs Allocated to CP Demand	$ 1,180,422	$ 667,784	$ 730,347	$ 843,646	$ 670,789	$ 757,921	$ 4,850,889	$ 10,021,465			
4b	Recoverable Costs Allocated to GCP Demand	$ 85,157	$ 85,157	$ 95,157	$ 145,157	$ 145,157	$ 160,157	$ 715,942	$ 1,270,374			
5	Retail Energy Jurisdictional Factor	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%					
6a	Retail CP Demand Jurisdictional Factor	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 1,281,266	$ 1,238,529	$ 1,264,635	$ 1,263,605	$ 1,490,254	$ 1,440,068	$ 7,978,358	$ 13,369,589			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 1,156,978	$ 654,501	$ 715,841	$ 826,891	$ 657,467	$ 742,868	$ 4,754,546	$ 9,822,433			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 85,157	$ 85,157	$ 95,157	$ 145,157	$ 145,157	$ 160,157	$ 715,942	$ 1,270,374			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 2,523,403	$ 1,978,187	$ 2,075,633	$ 2,235,653	$ 2,292,878	$ 2,343,093	$ 13,448,847	$ 24,462,397			

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-Up Amount for the Period
January 2012 - December 2012

Variance Report of Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		(1) Actual Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
2	Low NOx Burner Technology	$ 307,169	$ 307,169	$ (0)	0.0%
3b	Continuous Emission Monitoring Systems	653,321	693,652	(40,331)	-5.8%
4b	Clean Closure Equivalency	2,012	2,012	(0)	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks	1,041,411	1,027,134	14,277	1.4%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground	1,539	1,539	0	0.0%
8b	Oil Spill Cleanup/Response Equipment	190,333	141,165	49,169	34.8%
10	Relocate Storm Water Runoff	8,218	8,218	(0)	0.0%
NA	SO2 Allowances-Negative Return on Investment	(143,983)	(144,054)	72	0.0%
12	Scherer Discharge Pipeline	55,428	55,428	(0)	0.0%
20	Wastewater Discharge Elimination & Reuse	122,932	122,512	420	0.3%
21	St. Lucie Turtle Net	107,594	117,077	(9,483)	-8.1%
22	Pipeline Integrity Management	146,324	146,193	132	0.1%
23	SPCC-Spill Prevention, Control & Countermeasures	2,008,679	2,032,074	(23,395)	-1.2%
24	Manatee Reburn	3,280,524	3,291,987	(11,463)	-0.3%
25	Pt. Everglades ESP Technology	8,055,204	8,055,204	(0)	0.0%
26	UST Replacement/Removal	11,680	12,154	(474)	-3.9%
31	CAIR Compliance	55,308,578	58,932,516	(3,623,938)	-6.1%
33	MATS Project	12,470,431	12,514,950	(44,519)	-0.4%
35	Martin Plant Drinking Water System Compliance	25,998	25,997	1	0.0%
36	Low-Level Radioactive Waste Storage	723,551	1,305,096	(581,545)	-44.6%
37	DeSoto Next Generation Solar Energy Center	17,408,852	17,511,856	(103,004)	-0.6%
38	Space Coast Next Generation Solar Energy Center	8,246,055	8,246,105	(50)	0.0%
39	Martin Next Generation Solar Energy Center	48,039,902	47,607,281	432,621	0.9%
41	Manatee Temporary Heating System Project	899,349	941,820	(42,470)	-4.5%
42	Turkey Point Cooling Canal Monitoring Plan	398,925	398,925	0	0.0%
44	Martin Plant Barley Barber Swamp Iron Mitigation Project	18,934	16,960	1,974	11.6%
45	800 MW Unit ESP Project	6,171,976	0	6,171,976	NA
2	Total Investment Projects-Recoverable Costs	$ 165,560,936	$ 163,370,970	$ 2,189,968	1.3%
3	Recoverable Costs Allocated to Energy	$ 23,476,680	$ 23,830,888	$ (354,208)	-1.5%
4	Recoverable Costs Allocated to Demand	$ 142,084,256	$ 139,540,082	$ 2,544,174	1.8%

Notes:
Column(1) is the 12-Month Totals on Form 42-7E
Column(2) is the approved projected amount in accordance with
FPSC Order No. PSC-11-0553-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual / Estimated Amount for the Period
January 2012 - December 2012

Capital Investment Projects-Recoverable Costs
(In Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of Investment Projects (A)							
2	Low NOx Burner Technology	$ 26,468	$ 26,310	$ 26,151	$ 25,993	$ 25,835	$ 25,677	$ 156,433
3b	Continuous Emission Monitoring Systems	55,084	54,890	54,700	54,509	54,318	55,073	328,575
4b	Clean Closure Equivalency	171	170	170	169	169	168	1,016
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks	85,192	85,004	86,959	88,913	88,720	88,526	523,314
7	Relocate Turbine Lube Oil Underground Piping to Above Ground	131	130	130	129	129	128	778
8b	Oil Spill Cleanup/Response Equipment	12,939	12,891	14,600	17,044	16,407	16,343	90,224
10	Relocate Storm Water Runoff	693	691	690	688	687	686	4,135
NA	SO2 Allowances-Negative Return on Investment	(14,186)	(13,787)	(13,389)	(12,995)	(12,601)	(12,202)	(79,159)
12	Scherer Discharge Pipeline	4,691	4,678	4,665	4,652	4,639	4,626	27,949
20	Wastewater Discharge Elimination & Reuse	10,351	10,331	10,312	10,293	10,273	10,254	61,815
21	St. Lucie Turtle Net	8,935	8,947	8,959	8,967	8,974	8,979	53,761
22	Pipeline Integrity Management	0	0	0	0	0	11,018	11,018
23	SPCC - Spill Prevention, Control & Countermeasures	172,820	172,504	170,435	168,368	168,059	167,750	1,019,936
24	Manatee Reburn	277,360	276,809	275,634	274,464	273,924	273,383	1,651,574
25	Pt. Everglades ESP Technology	677,948	676,734	675,519	674,304	673,089	671,874	4,049,469
26	UST Removal / Replacement	1,017	1,014	1,012	1,011	995	964	6,013
31	CAIR Compliance	4,223,136	4,220,903	4,219,930	4,225,424	4,243,665	4,424,207	25,557,265
33	MATS Project	1,048,623	1,046,772	1,044,974	1,043,268	1,041,583	1,039,926	6,265,146
35	Martin Plant Drinking Water System Compliance	2,185	2,181	2,178	2,175	2,171	2,168	13,058
36	Low-Level Radioactive Waste Storage	60,700	60,633	60,557	60,479	60,402	60,335	363,107
37	DeSoto Next Generation Solar Energy Center	1,475,800	1,471,460	1,467,240	1,463,953	1,456,920	1,449,912	8,785,284
38	Space Coast Next Generation Solar Energy Center	696,934	694,693	693,012	691,331	689,648	687,966	4,153,585
39	Martin Next Generation Solar Energy Center	3,999,460	3,997,500	3,999,704	4,003,340	4,003,549	3,999,460	24,003,013
41	Manatee Temporary Heating System Project	73,821	73,748	73,671	73,642	73,627	73,563	442,072
42	Turkey Point Cooling Canal Monitoring Plan	33,480	33,437	33,394	33,351	33,308	33,265	200,236
44	Martin Plant Barley Barber Swamp Iron Mitigation Project	1,590	1,588	1,586	1,584	1,581	1,579	9,508
45	800 MW Unit ESP Project	147,811	335,646	379,356	387,848	409,005	441,823	2,101,488
2	Total Investment Projects - Recoverable Costs	$ 13,083,152	$ 13,255,879	$ 13,292,150	$ 13,302,904	$ 13,329,076	$ 13,537,451	$ 79,800,612
3	Recoverable Costs Allocated to Energy	$ 1,938,911	$ 1,936,163	$ 1,933,431	$ 1,931,444	$ 1,930,252	$ 1,943,055	$ 11,613,255
4	Recoverable Costs Allocated to Demand	$ 11,144,241	$ 11,319,717	$ 11,358,719	$ 11,371,460	$ 11,398,825	$ 11,594,397	$ 68,187,357
5	Retail Energy Jurisdictional Factor	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	
6	Retail Demand Jurisdictional Factor	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,901,709	$ 1,899,013	$ 1,896,333	$ 1,894,385	$ 1,893,215	$ 1,905,773	$ 11,390,428
8	Jurisdictional Demand Recoverable Costs (C)	$ 10,922,911	$ 11,094,901	$ 11,133,129	$ 11,145,617	$ 11,172,438	$ 11,364,126	$ 66,833,122
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 12,824,620	$ 12,993,914	$ 13,029,463	$ 13,040,002	$ 13,065,653	$ 13,269,899	$ 78,223,550

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual / Estimated Amount for the Period
January 2012 - December 2012

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)										
2	Low NOx Burner Technology	$ 25,518	$ 25,360	$ 25,202	$ 25,044	$ 24,885	$ 24,727	$ 150,736	$ 307,169		$ 307,169
3b	Continuous Emission Monitoring Systems	55,964	55,908	55,709	56,680	52,024	48,460	324,745	653,321		653,321
4b	Clean Closure Equivalency	167	167	166	166	165	165	996	2,012	1,857	155
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks	88,332	88,137	87,941	87,746	84,140	81,800	518,097	1,041,411	961,302	80,109
7	Relocate Turbine Lube Oil Underground Piping to Above Ground	128	127	127	126	126	125	760	1,539	1,421	118
8b	Oil Spill Cleanup/Response Equipment	16,049	16,444	17,067	16,999	16,849	16,699	100,108	190,333	175,692	14,641
10	Relocate Storm Water Runoff	684	683	681	680	679	677	4,084	8,218	7,586	632
NA	SO2 Allowances-Negative Return on Investment	(11,802)	(11,403)	(11,004)	(10,604)	(10,205)	(9,806)	(64,824)	(143,983)		(143,983)
12	Scherer Discharge Pipeline	4,613	4,599	4,586	4,573	4,560	4,547	27,479	55,428	51,164	4,264
20	Wastewater Discharge Elimination &Reuse	10,235	10,215	10,196	10,177	10,157	10,138	61,117	122,932	113,476	9,456
21	St. Lucie Turtle Net	8,983	8,979	8,974	8,970	8,966	8,962	53,834	107,594	99,317	8,277
22	Pipeline Integrity Management	22,019	21,988	21,956	21,924	21,893	25,526	135,306	146,324	135,069	11,255
23	SPCC - Spill Prevention, Control & Countermeasures	167,503	167,300	167,119	166,958	161,663	158,201	988,743	2,008,679	1,854,165	154,514
24	Manatee Reburn	272,843	272,302	271,762	271,221	270,681	270,141	1,628,950	3,280,524		3,280,524
25	Pt. Everglades ESP Technology	670,660	669,445	668,230	667,015	665,800	664,586	4,005,736	8,055,204		8,055,204
26	UST Removal / Replacement	949	947	945	944	942	940	5,667	11,680	10,782	898
31	CAIR Compliance	4,589,619	4,831,793	5,064,415	5,075,480	5,084,208	5,105,799	29,751,313	55,308,578	51,054,072	4,254,506
33	MATS Project	1,038,256	1,036,585	1,034,975	1,033,363	1,031,753	1,030,354	6,205,285	12,470,431	11,511,167	959,264
35	Martin Plant Drinking Water System Compliance	2,165	2,162	2,158	2,155	2,152	2,148	12,939	25,998	23,998	2,000
36	Low-Level Radioactive Waste Storage	60,268	60,190	60,113	60,035	59,958	59,880	360,444	723,551	667,894	55,657
37	DeSoto Next Generation Solar Energy Center	1,446,316	1,442,702	1,439,087	1,435,551	1,431,847	1,426,065	8,623,567	17,408,852	16,069,710	1,339,142
38	Space Coast Next Generation Solar Energy Center	686,284	684,602	682,920	681,237	679,555	677,872	4,092,470	8,246,055	7,611,743	634,312
39	Martin Next Generation Solar Energy Center	4,005,206	4,011,311	4,007,628	4,005,754	4,003,071	4,003,919	24,036,889	48,039,902	44,344,525	3,695,376
41	Manatee Temporary Heating System Project	73,499	73,434	73,370	73,305	73,241	90,428	457,277	899,349	830,169	69,180
42	Turkey Point Cooling Canal Monitoring Plan	33,222	33,179	33,136	33,093	33,050	33,007	198,688	398,925	368,239	30,686
44	Martin Plant Barley Barber Swamp Iron Mitigation Project	1,577	1,574	1,572	1,570	1,568	1,565	9,426	18,934	18,934	
45	800 MW Unit ESP Project	518,894	586,083	648,509	730,912	775,943	810,147	4,070,488	6,171,976	6,171,976	
2	Total Investment Projects - Recoverable Costs	$ 13,788,149	$ 14,094,813	$ 14,377,542	$ 14,461,075	$ 14,489,670	$ 14,549,074	$ 85,760,324	$ 165,560,936	$ 142,084,256	$23,476,680
3	Recoverable Costs Allocated to Energy	$ 1,955,836	$ 1,972,808	$ 1,988,173	$ 1,987,758	$ 1,980,799	$ 1,978,050	$ 11,863,425	$ 23,476,680		
4	Recoverable Costs Allocated to Demand	$ 11,832,313	$ 12,122,005	$ 12,389,368	$ 12,473,317	$ 12,508,871	$ 12,571,024	$ 73,896,899	$ 142,084,256		
5	Retail Energy Jurisdictional Factor	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%				
6	Retail Demand Jurisdictional Factor	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%				
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,918,309	$ 1,934,955	$ 1,950,026	$ 1,949,619	$ 1,942,793	$ 1,940,097	$ 11,635,799	$ 23,026,229		
8	Jurisdictional Demand Recoverable Costs (C)	$ 11,597,317	$ 11,881,256	$ 12,143,309	$ 12,225,591	$ 12,260,439	$ 12,321,357	$ 72,429,269	$ 139,262,391		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 13,515,627	$ 13,816,212	$ 14,093,335	$ 14,175,210	$ 14,203,232	$ 14,261,454	$ 84,065,068	$ 162,288,620		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	n/a
3.	Less: Accumulated Depreciation	$9,050,547	9,070,322	9,090,098	9,109,873	9,129,648	9,149,423	9,169,199	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$846,256	$826,481	$806,705	$786,930	$767,155	$747,380	$727,604	n/a
6.	Average Net Investment		836,368	816,593	796,818	777,042	757,267	737,492	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		5,335	5,209	5,083	4,957	4,831	4,704	$30,119
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,357	1,325	1,293	1,261	1,229	1,197	$7,662
8.	Investment Expenses								
	a. Depreciation (E)		19,775	19,775	19,775	19,775	19,775	19,775	$118,652
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$26,468	$26,310	$26,151	$25,993	$25,835	$25,677	$156,433

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	n/a
3.	Less: Accumulated Depreciation	$9,169,199	9,188,974	9,208,749	9,228,525	9,248,300	9,268,075	9,287,850	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$727,604	$707,829	$688,054	$668,278	$648,503	$628,728	$608,952	n/a
6.	Average Net Investment		717,717	697,941	678,166	658,391	638,615	618,840	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		4,578	4,452	4,326	4,200	4,074	3,948	55,697
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,165	1,133	1,101	1,068	1,036	1,004	14,169
8.	Investment Expenses								
	a. Depreciation (E)		19,775	19,775	19,775	19,775	19,775	19,775	237,303
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$25,518	$25,360	$25,202	$25,044	$24,885	$24,727	$307,169

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$875	$115,536	$116,411
	c. Retirements		$0	$0	$0	$0	$0	($70,124)	($70,124)
	d. Other		$0	($319)	($959)	$0	($0)	($3)	($1,280)
2.	Plant-In-Service/Depreciation Base (A)	$10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,233,350	10,348,886	n/a
3.	Less: Accumulated Depreciation	$6,385,777	6,410,179	6,434,262	6,457,705	6,482,107	6,506,509	6,460,989	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,846,698	$3,822,296	$3,798,213	$3,774,770	$3,750,369	$3,726,841	$3,887,897	n/a
6.	Average Net Investment		3,834,497	3,810,255	3,786,492	3,762,569	3,738,605	3,807,369	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		24,460	24,306	24,154	24,001	23,849	24,287	$145,057
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,223	6,183	6,145	6,106	6,067	6,179	$36,902
8.	Investment Expenses								
	a. Depreciation (E)		24,402	24,402	24,402	24,402	24,403	24,607	$146,616
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$55,084	$54,890	$54,700	$54,509	$54,318	$55,073	$328,575

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$28,077	$0	$0	$203,561	($1,212,116)	$0	($884,067)
	c. Retirements		$0	$0	$0	$0	$0	$0	($70,124)
	d. Other		$0	$0	$0	$0	($367,869)	$0	($369,149)
2.	Plant-In-Service/Depreciation Base (A)	$10,348,886	10,376,963	10,376,963	10,376,963	10,580,524	9,368,408	9,368,408	n/a
3.	Less: Accumulated Depreciation	$6,460,989	6,485,830	6,510,702	6,535,574	6,560,802	6,216,263	6,239,593	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,887,897	$3,891,133	$3,866,261	$3,841,389	$4,019,722	$3,152,145	$3,128,815	n/a
6.	Average Net Investment		3,889,515	3,878,697	3,853,825	3,930,556	3,585,934	3,140,480	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		24,811	24,742	24,584	25,073	22,875	20,033	287,175
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,312	6,294	6,254	6,379	5,819	5,096	73,056
8.	Investment Expenses								
	a. Depreciation (E)		24,841	24,872	24,872	25,228	23,330	23,330	293,089
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$55,964	$55,908	$55,709	$56,680	$52,024	$48,460	$653,321

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$41,612	41,612	41,612	41,612	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$28,925	28,995	29,064	29,134	29,203	29,273	29,342	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$12,686	$12,617	$12,547	$12,478	$12,408	$12,339	$12,269	n/a
6.	Average Net Investment		12,652	12,582	12,513	12,443	12,374	12,304	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		81	80	80	79	79	78	$478
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		21	20	20	20	20	20	$121
8.	Investment Expenses								
	a. Depreciation (E)		70	70	70	70	70	70	$417
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$171	$170	$170	$169	$169	$168	$1,016

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$41,612	41,612	41,612	41,612	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$29,342	29,412	29,481	29,551	29,620	29,690	29,759	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$12,269	$12,200	$12,130	$12,061	$11,991	$11,922	$11,852	n/a
6.	Average Net Investment		12,235	12,165	12,096	12,026	11,956	11,887	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		78	78	77	77	76	76	939
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		20	20	20	20	19	19	239
8.	Investment Expenses								
	a. Depreciation (E)		70	70	70	70	70	70	834
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$167	$167	$166	$166	$165	$165	$2,012

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$421,985	$329	$41	$185	$422,540
	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)	$11,726,140	11,726,140	11,726,140	12,148,126	12,148,455	12,148,496	12,148,681	n/a
3.	Less: Accumulated Depreciation	$4,001,436	4,024,910	4,048,384	4,072,315	4,096,703	4,121,092	4,145,481	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,724,705	$7,701,231	$7,677,757	$8,075,811	$8,051,751	$8,027,404	$8,003,199	n/a
6.	Average Net Investment		7,712,968	7,689,494	7,876,784	8,063,781	8,039,577	8,015,301	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		49,201	49,051	50,246	51,439	51,284	51,130	$302,351
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,517	12,479	12,782	13,086	13,047	13,007	$76,917
8.	Investment Expenses								
	a. Depreciation (E)		23,474	23,474	23,931	24,389	24,389	24,389	$144,046
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,192	$85,004	$86,959	$88,913	$88,720	$88,526	$523,314

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	($796,754)	$0	($374,214)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	($258,212)	$0	($258,212)
2.	Plant-In-Service/Depreciation Base (A)	$12,148,681	12,148,681	12,148,681	12,148,681	12,148,681	11,351,926	11,351,926	n/a
3.	Less: Accumulated Depreciation	$4,145,481	4,169,871	4,194,260	4,218,650	4,243,039	4,007,955	4,031,083	n/a
4.	CWIP - *Non Interest Bearing*	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,003,199	$7,978,810	$7,954,420	$7,930,031	$7,905,642	$7,343,971	$7,320,843	n/a
6.	Average Net Investment		7,991,005	7,966,615	7,942,226	7,917,836	7,624,806	7,332,407	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		50,975	50,819	50,663	50,508	48,639	46,773	600,728
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,968	12,928	12,889	12,849	12,374	11,899	152,824
8.	Investment Expenses								
	a. Depreciation (E)		24,389	24,389	24,389	24,389	23,128	23,128	287,859
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$88,332	$88,137	$87,941	$87,746	$84,140	$81,800	$1,041,411

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation	$22,388	22,450	22,512	22,574	22,636	22,698	22,761	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,642	$8,580	$8,518	$8,456	$8,394	$8,332	$8,269	n/a
6.	Average Net Investment		8,611	8,549	8,487	8,425	8,363	8,301	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		55	55	54	54	53	53	$324
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		14	14	14	14	14	13	$82
8.	Investment Expenses								
	a. Depreciation (E)		62	62	62	62	62	62	$372
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$131	$130	$130	$129	$129	$128	$778

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation	$22,761	22,823	22,885	22,947	23,009	23,071	23,133	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,269	$8,207	$8,145	$8,083	$8,021	$7,959	$7,897	n/a
6.	Average Net Investment		8,238	8,176	8,114	8,052	7,990	7,928	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		53	52	52	51	51	51	633
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		13	13	13	13	13	13	161
8.	Investment Expenses								
	a. Depreciation (E)		62	62	62	62	62	62	745
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$128	$127	$127	$126	$126	$125	$1,539

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($57,638)	$449	$366,140	$9,273	$1	$0	$318,225
	c. Retirements		($58,779)	($1,621)	$0	$0	$0	$0	($60,400)
	d. Other		($285)	($567)	$0	$0	($0)	$0	($853)
2.	Plant-In-Service/Depreciation Base (A)	$964,442	906,804	907,253	1,273,393	1,282,666	1,282,666	1,282,666	n/a
3.	Less: Accumulated Depreciation	$263,094	211,380	216,538	224,176	232,822	240,861	248,900	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$701,348	$695,424	$690,715	$1,049,217	$1,049,844	$1,041,805	$1,033,767	n/a
6.	Average Net Investment		698,386	693,070	869,966	1,049,530	1,045,825	1,037,786	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		4,455	4,421	5,550	6,695	6,671	6,620	$34,412
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,133	1,125	1,412	1,703	1,697	1,684	$8,754
8.	Investment Expenses								
	a. Depreciation (E)		7,350	7,346	7,639	8,646	8,039	8,039	$47,058
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$12,939	$12,891	$14,600	$17,044	$16,407	$16,343	$90,224

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$18,383	($2,600)	$0	$0	($13,891)	$320,117
	c. Retirements		$0	($38,773)	($2,600)	$0	$0	($13,891)	($115,664)
	d. Other		$0	$0	$0	$0	$0	$0	($853)
2.	Plant-In-Service/Depreciation Base (A)	$1,282,666	1,282,666	1,301,049	1,298,449	1,298,449	1,298,449	1,284,558	n/a
3.	Less: Accumulated Depreciation	$248,900	256,708	225,973	231,872	240,371	248,787	243,229	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,033,767	$1,025,958	$1,075,076	$1,066,577	$1,058,079	$1,049,662	$1,041,329	n/a
6.	Average Net Investment		1,029,863	1,050,517	1,070,827	1,062,328	1,053,870	1,045,495	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,569	6,701	6,831	6,777	6,723	6,669	74,682
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,671	1,705	1,738	1,724	1,710	1,697	18,999
8.	Investment Expenses								
	a. Depreciation (E)		7,808	8,038	8,499	8,499	8,416	8,334	96,652
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$16,049	$16,444	$17,067	$16,999	$16,849	$16,699	$190,333

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation	$53,226	53,403	53,579	53,756	53,933	54,109	54,286	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$64,568	$64,391	$64,215	$64,038	$63,861	$63,684	$63,508	n/a
6.	Average Net Investment		64,480	64,303	64,126	63,950	63,773	63,596	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		411	410	409	408	407	406	$2,451
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		105	104	104	104	103	103	$624
8.	Investment Expenses								
	a. Depreciation (E)		177	177	177	177	177	177	$1,060
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$693	$691	$690	$688	$687	$686	$4,135

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation	$54,286	54,463	54,639	54,816	54,993	55,169	55,346	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$63,508	$63,331	$63,154	$62,978	$62,801	$62,624	$62,448	n/a
6.	Average Net Investment		63,419	63,243	63,066	62,889	62,713	62,536	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		405	403	402	401	400	399	4,861
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		103	103	102	102	102	101	1,237
8.	Investment Expenses								
	a. Depreciation (E)		177	177	177	177	177	177	2,120
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$684	$683	$681	$680	$679	$677	$8,218

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$854,324	854,324	854,324	854,324	854,324	854,324	854,324	n/a
3.	Less: Accumulated Depreciation	$471,276	472,908	474,541	476,173	477,805	479,437	481,070	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$383,048	$381,416	$379,783	$378,151	$376,519	$374,886	$373,254	n/a
6.	Average Net Investment		382,232	380,599	378,967	377,335	375,702	374,070	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,438	2,428	2,417	2,407	2,397	2,386	$14,473
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		620	618	615	612	610	607	$3,682
8.	Investment Expenses								
	a. Depreciation (E)		1,632	1,632	1,632	1,632	1,632	1,632	$9,794
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,691	$4,678	$4,665	$4,652	$4,639	$4,626	$27,949

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) *Dismantlement only applies to Solar projects* - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$854,324	854,324	854,324	854,324	854,324	854,324	854,324	n/a
3.	Less: Accumulated Depreciation	$481,070	482,702	484,334	485,967	487,599	489,231	490,864	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$373,254	$371,622	$369,989	$368,357	$366,725	$365,092	$363,460	n/a
6.	Average Net Investment		372,438	370,805	369,173	367,541	365,908	364,276	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,376	2,365	2,355	2,345	2,334	2,324	28,572
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		604	602	599	596	594	591	7,269
8.	Investment Expenses								
	a. Depreciation (E)		1,632	1,632	1,632	1,632	1,632	1,632	19,588
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,613	$4,599	$4,586	$4,573	$4,560	$4,547	$55,428

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$1,235,070	1,235,070	1,235,070	1,235,070	1,235,070	1,235,070	1,235,070	n/a
3.	Less: Accumulated Depreciation	$242,830	245,251	247,672	250,093	252,513	254,934	257,355	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$992,240	$989,819	$987,399	$984,978	$982,557	$980,136	$977,715	n/a
6.	Average Net Investment		991,030	988,609	986,188	983,767	981,346	978,926	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,322	6,306	6,291	6,275	6,260	6,245	$37,699
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,608	1,604	1,600	1,596	1,593	1,589	$9,591
8.	Investment Expenses								
	a. Depreciation (E)		2,421	2,421	2,421	2,421	2,421	2,421	$14,525
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,351	$10,331	$10,312	$10,293	$10,273	$10,254	$61,815

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/Stormwater Reuse (Project No. 20)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$1,235,070	1,235,070	1,235,070	1,235,070	1,235,070	1,235,070	1,235,070	n/a
3.	Less: Accumulated Depreciation	$257,355	259,776	262,197	264,618	267,039	269,459	271,880	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$977,715	$975,294	$972,874	$970,453	$968,032	$965,611	$963,190	n/a
6.	Average Net Investment		976,505	974,084	971,663	969,242	966,821	964,401	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,229	6,214	6,198	6,183	6,167	6,152	74,842
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,585	1,581	1,577	1,573	1,569	1,565	19,040
8.	Investment Expenses								
	a. Depreciation (E)		2,421	2,421	2,421	2,421	2,421	2,421	29,050
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,235	$10,215	$10,196	$10,177	$10,157	$10,138	$122,932

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		($650)	($3,483)	($641)	($2,289)	($569)	($1,906)	($9,538)
2.	Plant-In-Service/Depreciation Base (A)	$352,942	352,942	352,942	352,942	352,942	352,942	352,942	n/a
3.	Less: Accumulated Depreciation	($697,407)	(697,528)	(700,481)	(700,593)	(702,352)	(702,392)	(703,769)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,050,349	$1,050,470	$1,053,423	$1,053,535	$1,055,295	$1,055,334	$1,056,711	n/a
6.	Average Net Investment		1,050,409	1,051,947	1,053,479	1,054,415	1,055,314	1,056,023	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,701	6,710	6,720	6,726	6,732	6,736	$40,325
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,705	1,707	1,710	1,711	1,713	1,714	$10,259
8.	Investment Expenses								
	a. Depreciation (E)		529	529	529	529	529	529	$3,176
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,935	$8,947	$8,959	$8,967	$8,974	$8,979	$53,761

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(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		$0	$0	$0	$0	$0	$0	$0
	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	($9,538)
2.	Plant-In-Service/Depreciation Base (A)	$352,942	352,942	352,942	352,942	352,942	352,942	352,942	n/a
3.	Less: Accumulated Depreciation	($703,769)	(703,239)	(702,710)	(702,180)	(701,651)	(701,122)	(700,592)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,056,711	$1,056,181	$1,055,652	$1,055,123	$1,054,593	$1,054,064	$1,053,534	n/a
6.	Average Net Investment		1,056,446	1,055,917	1,055,387	1,054,858	1,054,329	1,053,799	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,739	6,736	6,732	6,729	6,726	6,722	80,709
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,714	1,714	1,713	1,712	1,711	1,710	20,532
8.	Investment Expenses								
	a. Depreciation (E)		529	529	529	529	529	529	6,353
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,983	$8,979	$8,974	$8,970	$8,966	$8,962	$107,594

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$2,261,238	$2,261,238
	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	2,261,238	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	0	0	1,979	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$2,259,260	n/a
6.	Average Net Investment		0	0	0	0	0	1,129,630	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	0	7,206	$7,206
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	0	1,833	$1,833
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	1,979	$1,979
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$11,018	$11,018

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$752,070	$3,013,308
	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)	$2,261,238	2,261,238	2,261,238	2,261,238	2,261,238	2,261,238	3,013,308	n/a
3.	Less: Accumulated Depreciation	$1,979	5,936	9,893	13,850	17,807	21,764	26,380	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,259,260	$2,255,303	$2,251,345	$2,247,388	$2,243,431	$2,239,474	$2,986,929	n/a
6.	Average Net Investment		2,257,281	2,253,324	2,249,367	2,245,410	2,241,452	2,613,201	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		14,399	14,374	14,349	14,323	14,298	16,670	95,619
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		3,663	3,657	3,650	3,644	3,637	4,241	24,325
8.	Investment Expenses								
	a. Depreciation (E)		3,957	3,957	3,957	3,957	3,957	4,615	26,380
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$22,019	$21,988	$21,956	$21,924	$21,893	$25,526	$146,324

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	($366,141)	$59	$415	($1)	($365,668)
	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)	$20,000,812	20,000,812	20,000,812	19,634,671	19,634,730	19,635,145	19,635,144	n/a
3.	Less: Accumulated Depreciation	$3,317,828	3,357,312	3,396,797	3,435,991	3,474,896	3,513,801	3,552,707	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,682,984	$16,643,499	$16,604,015	$16,198,679	$16,159,834	$16,121,343	$16,082,437	n/a
6.	Average Net Investment		16,663,242	16,623,757	16,401,347	16,179,257	16,140,589	16,101,890	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		106,295	106,043	104,624	103,207	102,961	102,714	$625,844
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		27,041	26,977	26,616	26,256	26,193	26,130	$159,213
8.	Investment Expenses								
	a. Depreciation (E)		39,484	39,484	39,195	38,905	38,905	38,905	$234,879
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$172,820	$172,504	$170,435	$168,368	$168,059	$167,750	$1,019,936

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$13,429	$17,945	$10,880	$13,429	($999,232)	$13,426	($1,295,791)
	c. Retirements		$0	$0	($7,065)	$0	$0	$0	($7,065)
	d. Other		$0	$0	$0	$0	($170,385)	$0	($170,385)
2.	Plant-In-Service/Depreciation Base (A)	$19,635,144	19,648,573	19,666,518	19,677,398	19,690,827	18,691,595	18,705,021	n/a
3.	Less: Accumulated Depreciation	$3,552,707	3,591,623	3,630,522	3,662,343	3,701,253	3,568,051	3,605,332	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,082,437	$16,056,950	$16,035,996	$16,015,055	$15,989,573	$15,123,544	$15,099,689	n/a
6.	Average Net Investment		16,069,693	16,046,473	16,025,525	16,002,314	15,556,558	15,111,616	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		102,509	102,360	102,227	102,079	99,235	96,397	1,230,651
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		26,078	26,040	26,006	25,969	25,245	24,523	313,074
8.	Investment Expenses								
	a. Depreciation (E)		38,916	38,899	38,886	38,911	37,183	37,281	464,954
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$167,503	$167,300	$167,119	$166,958	$161,663	$158,201	$2,008,679

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	($578,976)	$0	$0	$0	($578,976)
	c. Retirements		$0	$0	($578,976)	$0	$0	$0	($578,976)
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base (A)	$31,749,547	31,749,547	31,749,547	31,170,571	31,170,571	31,170,571	31,170,571	n/a
3.	Less: Accumulated Depreciation	$5,649,884	5,718,674	5,787,465	5,276,653	5,344,189	5,411,725	5,479,261	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$26,099,663	$26,030,872	$25,962,082	$25,893,918	$25,826,382	$25,758,846	$25,691,309	n/a
6.	Average Net Investment		26,065,268	25,996,477	25,928,000	25,860,150	25,792,614	25,725,078	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		166,270	165,831	165,395	164,962	164,531	164,100	$991,090
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		42,299	42,187	42,076	41,966	41,856	41,747	$252,131
8.	Investment Expenses								
	a. Depreciation (E)		68,791	68,791	68,163	67,536	67,536	67,536	$408,354
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$277,360	$276,809	$275,634	$274,464	$273,924	$273,383	$1,651,574

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($578,976)
	c. Retirements		$0	$0	$0	$0	$0	$0	($578,976)
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base (A)	$31,170,571	31,170,571	31,170,571	31,170,571	31,170,571	31,170,571	31,170,571	n/a
3.	Less: Accumulated Depreciation	$5,479,261	5,546,798	5,614,334	5,681,870	5,749,406	5,816,943	5,884,479	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$25,691,309	$25,623,773	$25,556,237	$25,488,701	$25,421,165	$25,353,628	$25,286,092	n/a
6.	Average Net Investment		25,657,541	25,590,005	25,522,469	25,454,933	25,387,396	25,319,860	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		163,669	163,239	162,808	162,377	161,946	161,515	1,966,644
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		41,637	41,527	41,418	41,308	41,199	41,089	500,309
8.	Investment Expenses								
	a. Depreciation (E)		67,536	67,536	67,536	67,536	67,536	67,536	813,571
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$272,843	$272,302	$271,762	$271,221	$270,681	$270,141	$3,280,524

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$16,073,562	16,225,378	16,377,195	16,529,011	16,680,828	16,832,645	16,984,461	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$65,827,608	$65,675,791	$65,523,975	$65,372,158	$65,220,341	$65,068,525	$64,916,708	n/a
6.	Average Net Investment		65,751,699.53	65,599,883	65,448,066	65,296,250	65,144,433	64,992,617	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		419,430.01	418,462	417,493	416,525	415,556	414,588	$2,502,053
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		106,702	106,455	106,209	105,963	105,716	105,470	$636,516
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	$910,900
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$677,948	$676,734	$675,519	$674,304	$673,089	$671,874	$4,049,469

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$16,984,461	17,136,278	17,288,094	17,439,911	17,591,728	17,743,544	17,895,361	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$64,916,708	$64,764,892	$64,613,075	$64,461,258	$64,309,442	$64,157,625	$64,005,809	n/a
6.	Average Net Investment		64,840,800	64,688,983	64,537,167	64,385,350	64,233,534	64,081,717	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		413,619	412,651	411,683	410,714	409,746	408,777	4,969,243
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		105,224	104,977	104,731	104,485	104,238	103,992	1,264,162
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	1,821,799
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$670,660	$669,445	$668,230	$667,015	$665,800	$664,586	$8,055,204

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. *Retirements*		$0	$0	$0	$0	$0	$0	$0
	d. Other		$341	$0	$0	$0	$3,581	$3,581	$7,503
2.	Plant-In-Service/Depreciation Base (A)	$115,447	115,447	115,447	115,447	115,447	115,447	115,447	n/a
3.	Less: Accumulated Depreciation	$13,336	13,878	14,080	14,283	14,485	18,268	22,051	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$102,111	$101,568	$101,366	$101,164	$100,962	$97,179	$93,396	n/a
6.	Average Net Investment		101,840	101,467	101,265	101,063	99,070	95,287	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		650	647	646	645	632	608	$3,827
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		165	165	164	164	161	155	$974
8.	Investment Expenses								
	a. Depreciation (E)		202	202	202	202	202	202	$1,212
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,017	$1,014	$1,012	$1,011	$995	$964	$6,013

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(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		$0	$0	$0	$0	$0	$0	$0
	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	$7,503
2.	Plant-In-Service/Depreciation Base (A)	$115,447	115,447	115,447	115,447	115,447	115,447	115,447	n/a
3.	Less: Accumulated Depreciation	$22,051	22,253	22,455	22,657	22,859	23,061	23,263	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$93,396	$93,194	$92,992	$92,790	$92,588	$92,385	$92,183	n/a
6.	Average Net Investment		93,295	93,093	92,891	92,689	92,487	92,284	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		595	594	593	591	590	589	7,379
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		151	151	151	150	150	150	1,877
8.	Investment Expenses								
	a. Depreciation (E)		202	202	202	202	202	202	2,424
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$949	$947	$945	$944	$942	$940	$11,680

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward Is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$11,474	$880	$965	$1,759,723	$3,030,309	$2,041,546	$6,844,897
	b. Clearings to Plant		$0	($53,464)	$1,540,099	($105,678)	$1,849,831	$134,670,043	$137,900,831
	c. Retirements		$0	($124,608)	($107,071)	($105,677)	$0	$0	($337,355)
	d. Other		($38,187)	($54,366)	($24,922)	($461)	($6,215)	($1,464)	($125,615)
2.	Plant-In-Service/Depreciation Base (A)	$165,405,318	165,405,318	165,351,854	166,891,953	166,786,275	168,636,106	303,306,149	n/a
3.	Less: Accumulated Depreciation	$9,183,187	9,504,868	9,685,705	9,915,135	10,171,972	10,530,622	11,051,640	n/a
4.	CWIP - Non Interest Bearing	$326,732,729	326,744,297	326,745,176	325,022,127	326,781,849	327,980,245	196,871,975	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$482,954,860	$482,644,746	$482,411,325	$481,998,945	$483,396,152	$486,085,728	$489,126,484	n/a
6.	Average Net Investment		482,799,803	482,528,036	482,205,135	482,697,548	484,740,940	487,606,106	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		3,079,779	3,078,046	3,075,986	3,079,127	3,092,162	3,110,439	$18,515,539
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		783,488	783,046	782,522	783,322	786,638	791,287	$4,710,303
8.	Investment Expenses								
	a. Depreciation (E)		359,869	359,811	361,422	362,976	364,865	522,481	$2,331,423
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. *Property Expenses*								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,223,136	$4,220,903	$4,219,930	$4,225,424	$4,243,665	$4,424,207	$25,557,265

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) *March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.*
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(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		$3,621,859	$0	$0	$0	$0	$0	$10,466,756
	b. Clearings to Plant		$1,027,046	$202,740,480	$2,346,999	$1,568,234	$1,893,419	$4,106,536	$351,583,545
	c. Retirements		$0	$0	$0	$0	$0	$0	($337,355)
	d. Other		$0	$0	$0	$0	$0	$0	($125,615)
2.	Plant-In-Service/Depreciation Base (A)	$303,306,149	304,333,195	507,073,675	509,420,673	510,988,907	512,882,326	516,988,862	n/a
3.	Less: Accumulated Depreciation	$11,051,640	11,711,406	12,591,921	13,694,614	14,801,549	15,912,233	17,029,418	n/a
4.	CWIP - Non Interest Bearing	$196,871,975	200,493,834	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$489,126,484	$493,115,622	$494,481,753	$495,726,059	$496,187,359	$496,970,093	$499,959,444	n/a
6.	Average Net Investment		491,121,053	493,798,688	495,103,906	495,956,709	496,578,726	498,464,769	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		3,132,861	3,149,941	3,158,267	3,163,707	3,167,675	3,179,706	37,467,696
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		796,991	801,337	803,455	804,839	805,848	808,909	9,531,680
8.	Investment Expenses								
	a. Depreciation (E)		659,767	880,515	1,102,693	1,106,934	1,110,685	1,117,185	8,309,202
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,589,619	$4,831,793	$5,064,415	$5,075,480	$5,084,208	$5,105,799	$55,308,578

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: MATS (Project No. 33)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. *Expenditures/Additions*		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$429	$10,421	$18,847	$14,404	$24,667	$68,768
	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)	$106,879,091	106,879,091	106,879,520	106,889,941	106,908,788	106,923,193	106,947,859	n/a
3.	Less: Accumulated Depreciation	*$4,650,632*	*4,882,170*	*5,113,708*	*5,345,257*	5,576,837	5,808,450	6,040,104	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$102,228,459	$101,996,921	$101,765,812	$101,544,684	$101,331,952	$101,114,742	$100,907,755	n/a
6.	Average Net Investment		102,112,690	101,881,367	101,655,248	101,438,318	101,223,347	101,011,249	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		651,377	649,901	648,459	647,075	645,704	644,351	$3,886,866
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		165,708	165,333	164,966	164,614	164,265	163,921	$988,808
8.	Investment Expenses								
	a. Depreciation (E)		231,538	231,538	231,549	231,579	231,614	231,654	$1,389,472
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,048,623	$1,046,772	$1,044,974	$1,043,268	$1,041,583	$1,039,926	$6,265,146

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity *per FPSC Order No PSC-10-0153-FOF-EI.*
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: MATS (Project No. 33)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$11,885	$24,069	$23,965	$23,829	$24,351	$65,550	$242,417
	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)	$106,947,859	106,959,744	106,983,813	107,007,778	107,031,607	107,055,958	107,121,508	n/a
3.	Less: Accumulated Depreciation	$6,040,104	6,271,797	6,503,528	6,735,311	6,967,146	7,199,033	7,431,018	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$100,907,755	$100,687,948	$100,480,286	$100,272,468	$100,064,462	$99,856,925	$99,690,491	n/a
6.	Average Net Investment		100,797,852	100,584,117	100,376,377	100,168,465	99,960,693	99,773,708	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		642,989	641,626	640,301	638,975	637,649	636,456	7,724,862
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		163,575	163,228	162,891	162,553	162,216	161,913	1,965,184
8.	Investment Expenses								
	a. Depreciation (E)		231,692	231,731	231,783	231,835	231,887	231,985	2,780,386
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,038,256	$1,036,585	$1,034,975	$1,033,363	$1,031,753	$1,030,354	$12,470,431

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$235,391	235,391	235,391	235,391	235,391	235,391	235,391	n/a
3.	Less: Accumulated Depreciation	$13,654	14,066	14,477	14,889	15,301	15,713	16,125	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$221,738	$221,326	$220,914	$220,502	$220,090	$219,678	$219,266	n/a
6.	Average Net Investment		221,532	221,120	220,708	220,296	219,884	219,472	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,413	1,411	1,408	1,405	1,403	1,400	$8,439
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		360	359	358	357	357	356	$2,147
8.	Investment Expenses								
	a. Depreciation (E)		412	412	412	412	412	412	$2,472
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,185	$2,181	$2,178	$2,175	$2,171	$2,168	$13,058

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (Project No. 35)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$235,391	235,391	235,391	235,391	235,391	235,391	235,391	n/a
3.	Less: Accumulated Depreciation	$16,125	16,537	16,949	17,361	17,773	18,185	18,597	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$219,266	$218,854	$218,442	$218,030	$217,618	$217,206	$216,794	n/a
6.	Average Net Investment		219,060	218,648	218,236	217,824	217,412	217,000	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,397	1,395	1,392	1,390	1,387	1,384	16,784
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		355	355	354	353	353	352	4,270
8.	Investment Expenses								
	a. Depreciation (E)		412	412	412	412	412	412	4,943
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,165	$2,162	$2,158	$2,155	$2,152	$2,148	$25,998

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$1,958	$213	($7)	($2)	$3	$2,175	$4,340
	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)	$6,449,693	6,451,651	6,451,864	6,451,857	6,451,855	6,451,857	6,454,033	n/a
3.	Less: Accumulated Depreciation	$69,214	78,890	88,567	98,245	107,923	117,601	127,280	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	*Net Investment (Lines 2 - 3 + 4)*	$6,380,480	$6,372,762	$6,363,296	$6,353,612	$6,343,932	$6,334,257	$6,326,753	n/a
6.	Average Net Investment		6,376,621	6,368,029	6,358,454	6,348,772	6,339,094	6,330,505	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		*40,676*	*40,622*	*40,561*	*40,499*	*40,437*	40,382	$243,177
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		10,348	10,334	10,318	10,303	10,287	10,273	$61,864
8.	Investment Expenses								
	a. Depreciation (E)		9,676	9,678	9,678	9,678	9,678	9,679	$58,066
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$60,700	$60,633	$60,557	$60,479	$60,402	$60,335	$363,107

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). *See Form 42-8E, pages 55-59.*

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$4,340
	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)	$6,454,033	6,454,033	6,454,033	6,454,033	6,454,033	6,454,033	6,454,033	n/a
3.	Less: Accumulated Depreciation	$127,280	136,961	146,642	156,323	166,004	175,685	185,366	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$6,326,753	$6,317,072	$6,307,391	$6,297,710	$6,288,029	$6,278,347	$6,268,666	n/a
6.	Average Net Investment		6,321,912	6,312,231	6,302,550	6,292,869	6,283,188	6,273,507	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		40,327	40,266	40,204	40,142	40,080	40,019	484,215
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		10,259	10,243	10,228	10,212	10,196	10,181	123,183
8.	Investment Expenses								
	a. Depreciation (E)		9,681	9,681	9,681	9,681	9,681	9,681	116,153
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$60,268	$60,190	$60,113	$60,035	$59,958	$59,880	$723,551

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1. Investments									
a.	Expenditures/Additions		$55,682	$1,985	$0	$0	$0	$0	$57,667
b.	Clearings to Plant		$0	($184,983)	$63,399	$58	($633,999)	($354)	($755,878)
c.	Retirements		$0	$0	$0	$0	$0	($4,837)	($4,837)
d.	Other		$0	$0	$0	$0	$0	($448)	($448)
2. Plant-In-Service/Depreciation Base (A)		$152,746,852	152,746,852	152,561,870	152,625,269	152,625,327	151,991,328	151,990,974	n/a
3. Less: Accumulated Depreciation & Dismantlement		$10,999,047	11,422,983	11,846,720	12,270,344	12,694,055	13,116,894	13,533,576	n/a
4. CWIP - Non Interest Bearing		$0	55,682	57,667	57,667	57,667	57,667	57,667	n/a
5. Net Investment (Lines 2 - 3 + 4)		$141,747,806	$141,379,551	$140,772,817	$140,412,592	$139,988,940	$138,932,101	$138,515,065	n/a
6. Average Net Investment			141,563,678	141,076,184	140,592,705	140,200,766	139,460,520	138,723,583	n/a
a.	Average ITC Balance		40,709,121	40,587,055	40,464,989	40,342,923	40,220,857	40,098,791	
7. Return on Average Net Investment									
a.	Equity Component grossed up for taxes (B)		973,617	970,296	967,000	964,288	959,354	954,442	$5,788,996
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		238,641	237,823	237,012	236,349	235,121	233,898	$1,418,843
8. Investment Expenses									
a.	Depreciation (E)		417,878	417,678	417,565	417,652	416,780	415,908	$2,503,461
b.	Amortization (F)								
c.	Dismantlement (G)		6,059	6,059	6,059	6,059	6,059	6,059	$36,354
d.	Property Expenses								
e.	Amortization ITC Solar		(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	($962,370)
9. Total System Recoverable Expenses (Lines 7 & 8)			$1,475,800	$1,471,460	$1,467,240	$1,463,953	$1,456,920	$1,449,912	$8,785,284

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(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		$0	$0	$0	$0	$0	$0	$57,667
b.	Clearings to Plant		$0	$0	$0	$57,667	$0	($12,103)	($710,314)
c.	Retirements		$0	$0	$0	$0	$0	($12,103)	($16,940)
d.	Other		$0	$0	$0	$0	$0	$0	($448)
2.	Plant-In-Service/Depreciation Base (A)	$151,990,974	151,990,974	151,990,974	151,990,974	152,048,642	152,048,642	152,036,539	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$13,533,576	13,955,543	14,377,510	14,799,476	15,221,522	15,643,479	16,053,165	n/a
4.	CWIP - Non Interest Bearing	$57,667	57,667	57,667	57,667	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$138,515,065	$138,093,099	$137,671,132	$137,249,165	$136,827,119	$136,405,162	$135,983,373	n/a
6.	Average Net Investment	138,723,583	138,304,082	137,882,115	137,460,149	137,038,142	136,616,141	136,194,268	n/a
a.	Average ITC Balance	40,098,791	39,976,725	39,854,659	39,732,593	39,610,527	39,488,461	39,366,395	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		951,554	948,651	945,747	942,844	939,940	937,037	11,454,770
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		233,191	232,479	231,768	231,056	230,345	229,633	2,807,315
8.	Investment Expenses								
a.	Depreciation (E)		415,908	415,908	415,908	415,987	415,898	415,730	4,998,799
b.	Amortization (F)								
c.	Dismantlement (G)		6,059	6,059	6,059	6,059	6,059	6,059	$72,708
d.	Property Expenses								
e.	Amortization ITC Solar		(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	($1,924,740)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,446,316	$1,442,702	$1,439,087	$1,435,551	$1,431,847	$1,428,065	$17,408,852

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$0	$0	($233)	$0	$0	$75	($158)
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other		$0	$0	($568)	$4	($3)	$1	($566)
2.	Plant-In-Service/Depreciation Base (A)	$70,633,358	70,633,358	70,633,358	70,633,125	70,633,125	70,633,125	70,633,200	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$4,049,709	4,248,025	4,445,785	4,642,977	4,840,740	5,038,497	5,236,257	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$66,583,649	$66,385,333	$66,187,573	$65,990,148	$65,792,385	$65,594,629	$65,396,943	n/a
6.	Average Net Investment		66,484,491	66,286,453	66,088,861	65,891,267	65,693,507	65,495,786	n/a
a.	Average ITC Balance		17,352,939	17,301,750	17,250,561	17,199,372	17,148,183	17,096,994	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		454,191	452,839	451,490	450,141	448,791	447,441	$2,704,893
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		111,690	111,357	111,025	110,693	110,361	110,029	$665,155
8.	Investment Expenses								
a.	Depreciation (E)		195,404	194,848	194,848	194,847	194,847	194,848	$1,169,642
b.	Amortization (F)								
c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	$17,472
d.	Property Expenses								
e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	($403,578)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$696,934	$694,693	$693,012	$691,331	$689,648	$687,966	$4,153,585

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(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		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$0	$0	$0	$0	$0	$0	($158)
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other		$0	$0	$0	$0	$0	$0	($566)
2. Plant-in-Service/Depreciation Base (A)		$70,633,200	70,633,200	70,633,200	70,633,200	70,633,200	70,633,200	70,633,200	n/a
3. Less: Accumulated Depreciation & Dismantlement		$5,236,257	5,434,017	5,631,776	5,829,536	6,027,296	6,225,055	6,422,815	n/a
4. CWIP - Non Interest Bearing		$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)		$65,396,943	$65,199,183	$65,001,424	$64,803,664	$64,605,904	$64,408,145	$64,210,385	n/a
6. Average Net Investment			65,298,063	65,100,303	64,902,544	64,704,784	64,507,025	64,309,265	n/a
a.	Average ITC Balance	$17,096,994	17,045,805	16,994,616	16,943,427	16,892,238	16,841,049	16,789,860	
7. Return on Average Net Investment									
a.	Equity Component grossed up for taxes (B)		446,091	444,740	443,390	442,040	440,690	439,339	5,361,183
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		109,697	109,365	109,033	108,701	108,369	108,036	1,318,355
8. Investment Expenses									
a.	Depreciation (E)		194,848	194,848	194,848	194,848	194,848	194,848	2,338,728
b.	Amortization (F)								
c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	34,944
d.	Property Expenses								
e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	($807,156)
9. Total System Recoverable Expenses (Lines 7 & 8)			$686,284	$684,602	$682,920	$681,237	$679,555	$677,872	$8,246,055

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(in Dollars)

Line			Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments									
	a.	Expenditures/Additions		$134,405	$993,558	$1,553,421	$1,275,748	831,229.56	456,630.15	$5,244,992
	b.	Clearings to Plant		$1,098,617	$175,301	$217,674	$305,879	$30,682	$40,442	$1,868,595
	c.	Retirements		$0	$0	$0	$0	($28,995)	$0	($28,995)
	d.	Other		($9,848)	($547)	$1	($1,380)	($36)	($1,753)	($13,563)
2.	Plant-In-Service/Depreciation Base (A)		$399,543,272	400,641,889	400,817,190	401,034,864	401,340,743	401,371,425	401,411,867	n/a
3.	Less: Accumulated Depreciation & Dismantlement		$14,329,602	15,450,812	16,582,746	17,715,769	18,848,147	19,953,356	21,085,941	n/a
4.	CWIP - Non Interest Bearing		$973,287	283,117	1,274,541	2,738,772	3,908,581	4,739,810	5,196,441	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$386,186,957	$385,474,195	$385,508,986	$386,057,868	$386,401,176	$386,157,879	$385,522,367	n/a
6.	Average Net Investment			385,830,576	385,491,590	385,783,427	386,229,522	386,279,528	385,840,123	n/a
	a.	Average ITC Balance		119,225,809	118,882,011	118,538,213	118,194,415	117,850,617	117,506,819	
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		2,667,929	2,665,171	2,666,436	2,668,686	2,668,409	2,665,010	$16,001,640
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		652,224	651,599	651,997	652,646	652,652	651,864	$3,912,982
8.	Investment Expenses									
	a.	Depreciation (E)		1,102,211	1,103,634	1,104,174	1,104,912	1,105,393	1,105,491	$6,625,815
	b.	Amortization (F)								
	c.	Dismantlement (G)		28,847	28,847	28,847	28,847	28,847	28,847	$173,082
	d.	Property Expenses								
	e.	Amortization ITC Solar		(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	($2,710,506)
9.	Total System Recoverable Expenses (Lines 7 & 8)			$3,999,460	$3,997,500	$3,999,704	$4,003,340	$4,003,549	$3,999,460	$24,003,013

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(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		$1,213,679	$521,805	$700,552	$602,905	$547,538	$1,436,532	$10,268,003
	b.	Clearings to Plant		$6,270,504	$286,144	$200,552	$1,377,905	$547,538	$1,536,808	$12,088,046
	c.	Retirements		$0	$0	$0	$0	$0	$0	($28,995)
	d.	Other		$0	$0	$0	$0	$0	$0	($13,563)
2.	Plant-In-Service/Depreciation Base (A)		$401,411,867	407,682,371	407,968,516	408,169,068	409,546,973	410,094,511	411,631,319	n/a
3.	Less: Accumulated Depreciation & Dismantlement		$21,085,941	22,228,956	23,380,987	24,534,339	25,690,512	26,849,334	28,011,021	n/a
4.	CWIP - Non Interest Bearing		$5,196,441	139,615	375,276	875,276	100,276	100,276	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$385,522,367	$385,593,030	$384,962,805	$384,510,005	$383,956,736	$383,345,453	$383,620,297	n/a
6.	Average Net Investment			385,557,698	385,277,917	384,736,405	384,233,371	383,651,095	383,482,875	n/a
	a.	Average ITC Balance	$117,506,819	117,163,021	116,819,223	116,475,425	116,131,627	115,787,829	115,444,031	
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		2,662,612	2,660,231	2,656,181	2,652,376	2,648,065	2,646,396	31,927,501
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		651,330	650,801	649,847	648,955	647,935	647,587	7,809,437
8.	Investment Expenses									
	a.	Depreciation (E)		1,114,168	1,123,184	1,124,505	1,127,327	1,129,974	1,132,840	13,377,813
	b.	Amortization (F)								
	c.	Dismantlement (G)		28,847	28,847	28,847	28,847	28,847	28,847	346,164
	d.	Property Expenses								
	e.	Amortization ITC Solar		(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	($5,421,012)
9.	Total System Recoverable Expenses (Lines 7 & 8)			$4,005,206	$4,011,311	$4,007,628	$4,005,754	$4,003,071	$4,003,919	$48,039,902

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$113	($2,548)	$8,839	$65	($4)	$6,465
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$2,395	($0)	($32)	$0	$0	$0	$2,363
2.	Plant-In-Service/Depreciation Base (A)	$8,383,225	8,383,225	8,383,338	8,380,790	8,389,629	8,389,694	8,389,690	n/a
3.	Less: Accumulated Depreciation	$156,478	166,906	174,940	182,939	190,981	199,036	207,091	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,226,747	$8,216,319	$8,208,398	$8,197,851	$8,198,648	$8,190,658	$8,182,599	n/a
6.	Average Net Investment		8,221,533	8,212,359	8,203,125	8,198,250	8,194,653	8,186,628	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		52,445	52,387	52,328	52,297	52,274	52,222	$313,952
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		13,342	13,327	13,312	13,304	13,298	13,285	$79,869
8.	Investment Expenses								
	a. Depreciation (E)		8,034	8,034	8,031	8,042	8,055	8,055	$48,251
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$73,821	$73,748	$73,671	$73,642	$73,627	$73,563	$442,072

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$3,481,414	$3,487,879
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$2,363
2.	Plant-In-Service/Depreciation Base (A)	$8,389,690	8,389,690	8,389,690	8,389,690	8,389,690	8,389,690	11,871,104	n/a
3.	Less: Accumulated Depreciation	$207,091	215,147	223,202	231,258	239,313	247,369	258,761	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,182,599	$8,174,543	$8,166,488	$8,158,432	$8,150,377	$8,142,321	$11,612,343	n/a
6.	Average Net Investment		8,178,571	8,170,515	8,162,460	8,154,405	8,146,349	9,877,332	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		52,171	52,120	52,068	52,017	51,966	63,007	637,301
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		13,272	13,259	13,246	13,233	13,220	16,029	162,128
8.	Investment Expenses								
	a. Depreciation (E)		8,055	8,055	8,055	8,055	8,055	11,392	99,920
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$73,499	$73,434	$73,370	$73,305	$73,241	$90,428	$899,349

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.
(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: PTN Cooling Canal Monitoring System (Project No. 42)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	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)	$3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	n/a
3.	Less: Accumulated Depreciation	$67,592	72,966	78,341	83,715	89,089	94,463	99,837	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,515,161	$3,509,786	$3,504,412	$3,499,038	$3,493,664	$3,488,290	$3,482,916	n/a
6.	Average Net Investment		3,512,473	3,507,099	3,501,725	3,496,351	3,490,977	3,485,603	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		22,406	22,372	22,338	22,303	22,269	22,235	$133,922
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		5,700	5,691	5,683	5,674	5,665	5,656	$34,069
8.	Investment Expenses								
	a. Depreciation (E)		5,374	5,374	5,374	5,374	5,374	5,374	$32,245
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$33,480	$33,437	$33,394	$33,351	$33,308	$33,265	$200,236

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: PTN Cooling Canal Monitoring System (Project No. 42)
(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		$0	$0	$0	$0	$0	$0	$0
	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)	$3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	n/a
3.	Less: Accumulated Depreciation	$99,837	105,211	110,585	115,960	121,334	126,708	132,082	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,482,916	$3,477,542	$3,472,168	$3,466,793	$3,461,419	$3,456,045	$3,450,671	n/a
6.	Average Net Investment		3,480,229	3,474,855	3,469,480	3,464,106	3,458,732	3,453,358	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		22,200	22,166	22,132	22,098	22,063	22,029	266,610
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		5,648	5,639	5,630	5,622	5,613	5,604	67,825
8.	Investment Expenses								
	a. Depreciation (E)		5,374	5,374	5,374	5,374	5,374	5,374	64,490
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$33,222	$33,179	$33,136	$33,093	$33,050	$33,007	$398,925

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Barley Barber Swamp Iron Mitigation (Project No. 44)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$14	$0	$14
	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)	$164,704	164,704	164,704	164,704	164,704	164,719	164,719	n/a
3.	Less: Accumulated Depreciation	$1,820	2,108	2,396	2,684	2,972	3,261	3,549	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$162,885	$162,596	$162,308	$162,020	$161,732	$161,458	$161,170	n/a
6.	Average Net Investment		162,741	162,452	162,164	161,876	161,595	161,314	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,038	1,036	1,034	1,033	1,031	1,029	$6,201
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		264	264	263	263	262	262	$1,578
8.	Investment Expenses								
	a. Depreciation (E)		288	288	288	288	288	288	$1,729
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,590	$1,588	$1,586	$1,584	$1,581	$1,579	$9,508

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Barley Barber Swamp Iron Mitigation (Project No. 44)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$14
	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)	$164,719	164,719	164,719	164,719	164,719	164,719	164,719	n/a
3.	Less: Accumulated Depreciation	$3,549	3,837	4,125	4,414	4,702	4,990	5,278	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$161,170	$160,881	$160,593	$160,305	$160,017	$159,728	$159,440	n/a
6.	Average Net Investment		161,026	160,737	160,449	160,161	159,872	159,584	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,027	1,025	1,024	1,022	1,020	1,018	12,337
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		261	261	260	260	259	259	3,138
8.	Investment Expenses								
	a. Depreciation (E)		288	288	288	288	288	288	3,459
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,577	$1,574	$1,572	$1,570	$1,568	$1,565	$18,934

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: 800 MW ESP (Project No. 45)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions		$36,909,229	$10,003,840	$921,282	$1,201,143	$4,086,932	$4,115,746	$57,238,172
b.	Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other		($35,121)	($26)	$5	$1	($5)	($12)	($35,159)
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation	$0	(35,121)	(35,148)	(35,143)	(35,142)	(35,147)	(35,159)	n/a
4.	CWIP - Non interest Bearing	$0	36,909,229	46,913,069	47,834,351	49,035,493	53,122,425	57,238,172	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$36,944,350	$46,948,216	$47,869,493	$49,070,635	$53,157,572	$57,273,331	n/a
6.	Average Net Investment		18,472,175	41,946,283	47,408,855	48,470,064	51,114,103	55,215,452	n/a
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		117,834	267,575	302,421	309,190	326,057	352,219	$1,675,297
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		29,977	68,070	76,935	78,657	82,948	89,604	$426,191
8.	Investment Expenses								
a.	Depreciation (E)		0	0	0	0	0	0	$0
b.	Amortization (F)								
c.	Dismantlement (G)								
d.	Property Expenses								
e.	Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$147,811	$335,646	$379,356	$387,848	$409,005	$441,823	$2,101,488

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: 800 MW ESP (Project No. 45)
(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		$383,369	$1,538,798	$12,476,771	$6,772,536	$4,749,262	$4,066,386	$87,225,294
	b. Clearings to Plant		$54,745,447	$836,917	$5,935,265	$0	$0	$0	$61,517,629
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	($35,159)
2.	Plant-In-Service/Depreciation Base (A)	$0	54,745,447	55,582,364	61,517,629	61,517,629	61,517,629	61,517,629	n/a
3.	Less: Accumulated Depreciation	($35,159)	24,149	143,670	270,529	403,817	537,105	670,393	n/a
4.	CWIP - Non Interest Bearing	$57,238,172	2,876,094	3,577,975	10,119,481	16,892,017	21,641,279	25,707,665	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$57,273,331	$57,597,392	$59,016,669	$71,366,581	$78,005,829	$82,621,803	$86,554,901	n/a
6.	Average Net Investment		57,435,362	58,307,030	65,191,625	74,686,205	80,313,816	84,588,352	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		366,380	371,940	415,857	476,423	512,322	539,589	21,198,051
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		93,206	94,621	105,793	121,201	130,333	137,270	5,392,727
8.	Investment Expenses								
	a. Depreciation (E)		59,308	119,522	126,858	133,288	133,288	133,288	3,036,976
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$518,894	$586,083	$648,509	$730,912	$775,943	$810,147	$6,171,976

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 55-59.

(B) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) March 2010 forward is 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line			Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount	
1	Working Capital - Dr (Cr)										
a	158.100	Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
b	158.200	Allowances Withheld	0	0	0	0	0	0	0		
c	182.300	Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
d	254.900	Other Regulatory Liabilities-Gains	(1,797,695)	(1,747,905)	(1,698,116)	(1,648,326)	(1,599,658)	(1,549,838)	(1,499,929)		
2	Total Working Capital		($1,797,695)	($1,747,905)	($1,698,116)	($1,648,326)	($1,599,658)	($1,549,838)	($1,499,929)		
3	Average Net Working Capital Balance			(1,772,800)	(1,723,010)	(1,673,221)	(1,623,992)	(1,574,748)	(1,524,883)		
4	Return on Average Net Working Capital Balance										
a		Equity Component grossed up for taxes (A)		(11,309)	(10,991)	(10,673)	(10,359)	(10,045)	(9,727)		
b		Debt Component (Line 6 x 1.6698% x 1/12)		(2,877)	(2,796)	(2,715)	(2,635)	(2,556)	(2,475)		
5	Total Return Component			($14,186)	($13,787)	($13,389)	($12,995)	($12,601)	($12,202)	($79,159)	(D)
6	Expense Dr (Cr)										
a	411.800	Gains from Dispositions of Allowances		(49,790)	(49,790)	(49,790)	(50,223)	(49,953)	(49,909)		
b	411.900	Losses from Dispositions of Allowances		0	0	0	0	0	0		
c	509.000	Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)			($49,790)	($49,790)	($49,790)	($50,223)	($49,953)	($49,909)	($299,455)	(E)
8	Total System Recoverable Expenses (Lines 5+7)			(63,975)	(63,577)	(63,178)	(63,218)	(62,554)	(62,111)		
a		Recoverable Costs Allocated to Energy		(63,975)	(63,577)	(63,178)	(63,218)	(62,554)	(62,111)		
b		Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9		Energy Jurisdictional Factor		98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%		
10		Demand Jurisdictional Factor		98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%		
11		Retail Energy-Related Recoverable Costs (B)		(62,748)	(62,357)	(61,966)	(62,005)	(61,354)	(60,919)		
12		Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)			($62,748)	($62,357)	($61,966)	($62,005)	($61,354)	($60,919)		

Notes:

(A) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(B) Line 8a times Line 9

(C) Line 8b times Line 10

(D) Line 5 is reported on Capital Schedule

(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(In Dollars)

Line			Beginning of Period Amount	July Estimate	August Estimate	September Estimate	October Estimate	November Estimate	December Estimate	Twelve Month Amount	
1	Working Capital Dr (Cr)										
	a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b	158.200 Allowances Withheld	$0	0	0	0	0	0	0		
	c	182.300 Other Regulatory Assets-Losses	$0	0	0	0	0	0	0		
	d	254.900 Other Regulatory Liabilities-Gains	(1,499,929)	(1,450,020)	(1,400,111)	(1,350,201)	(1,300,292)	(1,250,383)	(1,200,474)		
2	Total Working Capital		($1,499,929)	($1,450,020)	($1,400,111)	($1,350,201)	($1,300,292)	($1,250,383)	($1,200,474)		
3	Average Net Working Capital Balance			(1,474,974)	(1,425,065)	(1,375,156)	(1,325,247)	(1,275,338)	(1,225,429)		
4	Return on Average Net Working Capital Balance										
	a	Equity Component grossed up for taxes (A)		(9,409)	(9,090)	(8,772)	(8,454)	(8,135)	(7,817)		
	b	Debt Component (Line 6 x 1.6698% x 1/12)		(2,394)	(2,313)	(2,232)	(2,151)	(2,070)	(1,989)		
5	Total Return Component			($11,802)	($11,403)	($11,004)	($10,604)	($10,205)	($9,806)	($143,983)	(D)
6	Expense Dr (Cr)										
	a	411.800 Gains from Dispositions of Allowances		(49,909)	(49,909)	(49,909)	(49,909)	(49,909)	(49,909)		
	b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
	c	509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)			($49,909)	($49,909)	($49,909)	($49,909)	($49,909)	($49,909)	($598,910)	(E)
8	Total System Recoverable Expenses (Lines 5+7)			(61,712)	(61,312)	(60,913)	(60,513)	(60,114)	(59,715)		
	a	Recoverable Costs Allocated to Energy		(61,712)	(61,312)	(60,913)	(60,513)	(60,114)	(59,715)		
	b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9		Energy Jurisdictional Factor		98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%		
10		Demand Jurisdictional Factor		98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%		
11		Retail Energy-Related Recoverable Costs (B)		(60,528)	(60,136)	(59,744)	(59,352)	(58,961)	(58,569)		
12		Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)			($60,528)	($60,136)	($59,744)	($59,352)	($58,961)	($58,569)		

Notes:

(A) March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2011	Estimated Balance December 2012
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	2,689,232.57	2,689,232.57
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.50%	2,563,376.41	2,563,376.41
	02 - Steam Generation Plant	Turkey Pt U2	31200	2.50%	2,275,221.65	2,275,221.65
02 - Low NOX Burner Technology Total					**9,896,802.90**	**9,896,802.90**
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	Cutler Comm	31100	1.70%	64,883.87	0.00
	02 - Steam Generation Plant	Cutler Comm	31200	2.20%	36,276.52	0.00
	02 - Steam Generation Plant	Cutler U5	31200	2.20%	310,454.41	0.00
	02 - Steam Generation Plant	Cutler U6	31200	2.20%	311,861.95	0.00
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	2.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	477,896.88	505,973.88
	02 - Steam Generation Plant	Manatee U2	31100	2.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	508,552.43	508,552.43
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	2.10%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	2.60%	529,318.55	542,174.96
	02 - Steam Generation Plant	Martin U2	31100	2.10%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	2.60%	525,201.70	529,517.79
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.30%	67,787.69	67,787.69
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	458,060.74	458,060.74
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	480,321.84	480,321.84
	02 - Steam Generation Plant	PtEverglades U3	31200	2.30%	507,658.33	507,658.33
	02 - Steam Generation Plant	PtEverglades U4	31200	2.30%	517,303.41	517,303.41
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	54,282.08	0.00
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	434,357.43	0.00
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	779.50	779.50
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	779.51	779.51
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.10%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm	31200	2.50%	37,954.50	37,954.50
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.50%	545,584.31	545,584.31
	02 - Steam Generation Plant	Turkey Pt U2	31200	2.50%	504,688.53	504,688.53
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	3.40%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	4.30%	462,254.20	462,254.20
	05 - Other Generation Plant	FtLauderdale U5	34300	4.20%	473,359.99	473,359.99
	05 - Other Generation Plant	FtMyers U2	34300	4.20%	23,619.18	171,024.18
	05 - Other Generation Plant	FtMyers U3	34300	5.20%	2,282.97	2,282.97
	05 - Other Generation Plant	Martin U3	34300	4.20%	416,872.29	444,950.29
	05 - Other Generation Plant	Martin U4	34300	4.20%	409,474.06	437,552.06
	05 - Other Generation Plant	Martin U8	34300	4.30%	13,693.21	13,693.21
	05 - Other Generation Plant	Putnam Comm	34100	2.60%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	4.20%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	4.00%	346,616.08	346,616.08
	05 - Other Generation Plant	Putnam U2	34300	3.30%	380,355.07	380,355.07
	05 - Other Generation Plant	Sanford U4	34300	4.80%	98,339.95	147,960.65
	05 - Other Generation Plant	Sanford U5	34300	4.20%	56,521.05	106,138.68
03 - Continuous Emission Monitoring Total					**10,232,475.17**	**9,368,407.74**
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.10%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					**41,611.58**	**41,611.58**

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2011	Estimated Balance December 2012
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	94,329.22	94,329.22
	02 - Steam Generation Plant	Martin U1	31100	2.10%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	796,754.11	0.00
	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.60%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.10%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	133,478.89	133,478.89
	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	2,359,099.94	2,781,640.18
	05 - Other Generation Plant	Putnam Comm	34200	2.90%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					**11,726,140.29**	**11,351,926.42**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	47,081.78	46,881.78
	02 - Steam Generation Plant	Martin Comm	31600	2.40%	23,107.32	23,107.32
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	(38.54)	366,102.24
	02 - Steam Generation Plant	Amortizable	31650	5-Year	86,360.48	143,516.48
	02 - Steam Generation Plant	Amortizable	31670	7-Year	394,958.99	314,014.73
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	354,919.37	358,329.97
	05 - Other Generation Plant	Amortizable	34650	5-Year	22,458.48	22,458.48
	05 - Other Generation Plant	Amortizable	34670	7-Year	31,180.89	5,734.43
	08 - General Plant		39000	2.10%	4,412.76	4,412.76
08 - Oil Spill Clean-up/Response Equipment Total					**964,441.53**	**1,284,558.19**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31100	2.10%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	2.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	2.60%	689.11	689.11
12 - Scherer Discharge Pipline Total					**854,323.70**	**854,323.70**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	Martin U1	31200	2.60%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	2.60%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	437,403.66	437,403.66
20 - Wastewater/Stormwater Discharge Elimination Total					**1,235,070.35**	**1,235,070.35**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	352,942.34	352,942.34
21 - St. Lucie Turtle Nets Total					**352,942.34**	**352,942.34**
22 - Pipeline Integrity						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	0.00	752,070.00
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	0.00	2,261,238.29
22 - Pipeline Integrity Total					**0.00**	**3,013,308.29**

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2011	Estimated Balance December 2012
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	Cutler Comm	31400	2.20%	12,236.00	0.00
	02 - Steam Generation Plant	Cutler U5	31400	2.20%	18,388.00	0.00
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	807,718.60	807,718.60
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	33,272.38	33,272.38
	02 - Steam Generation Plant	Manatee Comm	31500	2.40%	26,325.43	26,325.43
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	45,749.52	45,749.52
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	37,431.45	37,431.45
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	343,785.10	343,785.10
	02 - Steam Generation Plant	Martin Comm	31500	2.40%	34,754.74	34,754.74
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	3,333,894.85	2,967,754.07
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.30%	159,754.32	159,754.32
	02 - Steam Generation Plant	PtEverglades Comm	31500	2.00%	7,782.85	7,782.85
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	850,530.75	0.00
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	211,727.22	0.00
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.10%	92,013.09	92,013.09
	02 - Steam Generation Plant	Turkey Pt Comm	31500	2.20%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	1,019,614.24	1,019,614.24
	03 - Nuclear Generation Plant	StLucie U1	32400	1.80%	437,945.38	437,945.38
	03 - Nuclear Generation Plant	StLucie U2	32300	2.40%	552,389.64	552,389.64
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	6.00%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.30%	98,714.92	178,935.92
	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.20%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2	34300	4.20%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3	34500	3.40%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.50%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34200	3.80%	84,868.00	84,868.00
	05 - Other Generation Plant	PtEverglades GTs	34100	2.20%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	1,835,189.50	1,835,189.50
	05 - Other Generation Plant	PtEverglades GTs	34500	2.10%	7,782.85	7,782.85
	05 - Other Generation Plant	Putnam Comm	34100	2.60%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	2.90%	1,730,934.74	1,730,934.74
	05 - Other Generation Plant	Putnam Comm	34500	2.50%	60,746.93	60,746.93
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	0.00
	06 - Transmission Plant - Electric		35200	1.90%	1,042,156.83	1,058,508.31
	06 - Transmission Plant - Electric		35300	2.60%	177,981.88	177,981.88
	06 - Transmission Plant - Electric		35800	1.80%	65,655.25	65,655.25
	07 - Distribution Plant - Electric		36100	1.90%	2,961,658.64	3,026,351.11
	07 - Distribution Plant - Electric		36670	2.00%	70,499.45	79,531.45
	08 - General Plant		39000	2.10%	146,691.32	146,691.32
23 - Spill Prevention Clean-Up & Countermeasures Total					**20,000,811.53**	**18,705,020.63**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	16,687,067.37	16,687,067.37
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	15,062,479.29	14,483,503.50
24 - Manatee Reburn Total					**31,749,546.66**	**31,170,570.87**
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31100	1.90%	298,709.93	298,709.93
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	10,404,603.15	10,404,603.15
	02 - Steam Generation Plant	PtEverglades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	PtEverglades U1	31600	2.10%	307,032.30	307,032.30
	02 - Steam Generation Plant	PtEverglades U2	31100	1.90%	184,084.01	184,084.01
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	11,979,735.29	11,979,735.29
	02 - Steam Generation Plant	PtEverglades U2	31500	2.00%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	PtEverglades U2	31600	2.10%	324,086.94	324,086.94
	02 - Steam Generation Plant	PtEverglades U3	31100	1.90%	713,693.44	713,693.44
	02 - Steam Generation Plant	PtEverglades U3	31200	2.30%	18,160,533.65	18,160,533.65
	02 - Steam Generation Plant	PtEverglades U3	31500	2.00%	4,304,056.69	4,304,056.69
	02 - Steam Generation Plant	PtEverglades U3	31600	2.10%	528,541.18	528,541.18
	02 - Steam Generation Plant	PtEverglades U4	31100	1.90%	313,275.79	313,275.79
	02 - Steam Generation Plant	PtEverglades U4	31200	2.30%	20,646,501.29	20,646,501.29
	02 - Steam Generation Plant	PtEverglades U4	31500	2.00%	6,729,950.05	6,729,950.05
	02 - Steam Generation Plant	PtEverglades U4	31600	2.10%	551,535.30	551,535.30
25 - PPE ESP Technology Total					**81,901,169.49**	**81,901,169.49**

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2011	Estimated Balance December 2012
26 - UST Remove/Replace						
	08 - General Plant		39000	2.10%	115,446.69	115,446.69
26 - UST Remove/Replace Total					**115,446.69**	**115,446.69**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	102,052.47	102,052.47
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	20,059,060.47	20,059,060.47
	02 - Steam Generation Plant	Manatee U1	31400	2.60%	7,168,979.87	7,240,727.65
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	17,191,439.24	20,461,497.52
	02 - Steam Generation Plant	Manatee U2	31400	2.60%	7,918,302.41	7,912,961.94
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	518,274.99	518,274.99
	02 - Steam Generation Plant	Martin Comm	31400	2.60%	287,257.77	287,257.77
	02 - Steam Generation Plant	Martin U1	31200	2.60%	20,695,251.33	19,504,076.53
	02 - Steam Generation Plant	Martin U1	31400	2.60%	7,794,707.32	7,794,707.32
	02 - Steam Generation Plant	Martin U2	31200	2.60%	19,057,799.99	20,248,974.79
	02 - Steam Generation Plant	Martin U2	31400	2.60%	7,385,556.36	7,477,119.82
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	0.00	348,261,192.39
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	27,708,298.93	27,708,298.93
	02 - Steam Generation Plant	SJRPP U1	31500	2.40%	455,145.91	455,145.91
	02 - Steam Generation Plant	SJRPP U1	31600	2.40%	9,137.83	9,137.83
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	26,630,303.07	26,524,626.30
	02 - Steam Generation Plant	SJRPP U2	31500	2.40%	426,219.91	426,219.91
	02 - Steam Generation Plant	SJRPP U2	31600	2.40%	9,591.24	9,591.24
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.90%	110,241.57	110,241.57
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	57,855.19	57,855.19
	05 - Other Generation Plant	Martin Comm	34100	3.50%	763,350.13	763,350.13
	05 - Other Generation Plant	Martin Comm	34300	4.30%	244,343.38	244,343.38
	05 - Other Generation Plant	Martin Comm	34500	3.40%	292,498.67	292,498.67
	05 - Other Generation Plant	PtEverglades GTs	34300	3.40%	107,874.44	107,874.44
	07 - Distribution Plant - Electric		36500	3.90%	411,775.23	411,775.23
31 - Clean Air Interstate Rule (CAIR) Total					**165,405,317.72**	**516,988,862.39**
33 - Clean Air Mercury Rule (CAMR)						
	02 - Steam Generation Plant	Scherer U4	31100	2.10%	67,478.60	81,956.17
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	106,777,872.99	106,998,574.04
	02 - Steam Generation Plant	Scherer U4	31500	2.40%	33,739.30	40,978.08
33 - Clean Air Mercury Rule (CAMR) Total					**106,879,090.89**	**107,121,508.29**
35 - Martin Drinking Water System						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	235,391.32	235,391.32
35 - Martin Drinking Water System Total					**235,391.32**	**235,391.32**
36 - Low Level Waste Storage (LLW)						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	6,449,693.36	6,454,032.88
36 - Low Level Waste Storage (LLW) Total					**6,449,693.36**	**6,454,032.88**
37 - DeSoto Solar Energy Center						
	05 - Other Generation Plant	Desoto Solar	34000	0.00%	255,507.00	255,507.00
	05 - Other Generation Plant	Desoto Solar	34100	3.30%	4,521,406.52	4,502,770.01
	05 - Other Generation Plant	Desoto Solar	34300	3.30%	115,754,063.29	115,303,899.63
	05 - Other Generation Plant	Desoto Solar	34500	3.30%	26,239,255.03	26,137,101.14
	05 - Other Generation Plant	Desoto Solar	34500	3.30%	0.00	57,667.38
	05 - Other Generation Plant	Amortizable	34630	3-Year	12,102.91	0.00
	05 - Other Generation Plant	Amortizable	34650	5-Year	21,934.62	21,934.62
	05 - Other Generation Plant	Amortizable	34670	7-Year	59,592.09	59,592.09
	06 - Transmission Plant - Electric		35200	1.90%	6,543.06	5,655.29
	06 - Transmission Plant - Electric		35300	2.60%	704,626.32	520,413.28
	06 - Transmission Plant - Electric		35310	2.90%	1,712,305.00	1,712,305.00
	06 - Transmission Plant - Electric		35500	3.40%	394,417.57	394,417.57
	06 - Transmission Plant - Electric		35600	3.20%	191,357.87	191,357.87
	07 - Distribution Plant - Electric		36100	1.90%	608,244.37	608,254.67
	07 - Distribution Plant - Electric		36200	2.60%	2,214,956.51	2,215,122.51
	08 - General Plant		39220	9.40%	28,426.16	28,426.16
	08 - General Plant	Amortizable	39720	7-Year	22,114.04	22,114.40
37 - DeSoto Solar Energy Center Total					**152,746,852.36**	**152,036,538.62**

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site / Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2011	Estimated Balance December 2012
38 - Spacecoast Solar Energy Center						
	01 - Intangible Plant	Amortizable	30300	30-Year	6,359,027.00	6,359,027.00
	05 - Other Generation Plant	Space Coast Solar	34100	3.30%	3,838,725.58	3,838,725.58
	05 - Other Generation Plant	Space Coast Solar	34300	3.30%	51,606,083.22	51,606,083.22
	05 - Other Generation Plant	Space Coast Solar	34500	3.30%	6,126,698.76	6,126,698.76
	05 - Other Generation Plant	Amortizable	34630	3-Year	7,271.71	7,271.71
	05 - Other Generation Plant	Amortizable	34650	5-Year	9,438.49	9,438.49
	05 - Other Generation Plant	Amortizable	34670	7-Year	51,560.44	51,560.44
	06 - Transmission Plant - Electric		35300	2.60%	139,390.84	139,390.84
	07 - Distribution Plant - Electric		36100	1.90%	269,805.86	269,799.42
	07 - Distribution Plant - Electric		36200	2.60%	2,187,146.99	2,186,995.62
	08 - General Plant		39220	9.40%	31,858.14	31,858.14
	08 - General Plant	Amortizable	39720	7-Year	6,350.66	6,350.60
38 - Spacecoast Solar Energy Center Total					**70,633,357.69**	**70,633,199.82**
39 - Martin Solar Energy Center						
	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844.31	216,844.31
	05 - Other Generation Plant	Martin Solar	34100	3.30%	184,125.52	19,859,164.35
	05 - Other Generation Plant	Martin Solar	34300	3.30%	397,293,384.66	385,420,309.58
	05 - Other Generation Plant	Martin Solar	34500	3.30%	21,636.52	4,059,060.77
	05 - Other Generation Plant	Martin Solar	34600	3.30%	1,299.31	1,299.31
	05 - Other Generation Plant	Martin U8	34300	4.30%	379,929.68	423,125.67
	05 - Other Generation Plant	Amortizable	34650	5-Year	21,384.00	21,384.00
	05 - Other Generation Plant	Amortizable	34670	7-Year	0.00	4,910.32
	06 - Transmission Plant - Electric		35500	3.40%	603,691.67	603,691.67
	06 - Transmission Plant - Electric		35600	3.20%	364,159.38	364,159.38
	07 - Distribution Plant - Electric		36400	4.10%	9,282.42	9,282.42
	07 - Distribution Plant - Electric		36660	1.50%	94,476.14	94,476.14
	07 - Distribution Plant - Electric		36760	2.60%	2,728.36	2,728.36
	08 - General Plant		39220	9.40%	25,193.18	25,193.18
	08 - General Plant		39240	11.10%	205,307.14	405,859.14
	08 - General Plant		39290	3.50%	97,633.07	97,633.07
	08 - General Plant	Amortizable	39420	7-Year	18,992.89	18,992.89
	08 - General Plant	Amortizable	39720	7-Year	3,203.99	3,203.99
39 - Martin Solar Energy Center Total					**399,643,272.24**	**411,631,318.55**
41 - Manatee Heaters						
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	4,043,057.47	4,042,458.97
	02 - Steam Generation Plant	PtEverglades Comm	31400	2.30%	0.00	3,481,413.82
	02 - Steam Generation Plant	Riviera Comm	31400	0.60%	2,605,268.34	2,605,268.34
	06 - Transmission Plant - Electric		35300	2.60%	276,404.06	276,404.06
	07 - Distribution Plant - Electric		36100	1.90%	29,779.49	29,981.19
	07 - Distribution Plant - Electric		36200	2.60%	488,424.42	488,123.56
	07 - Distribution Plant - Electric		36400	4.10%	223,459.91	226,154.57
	07 - Distribution Plant - Electric		36500	3.90%	302,616.24	307,184.11
	07 - Distribution Plant - Electric		36660	1.50%	221,325.50	221,325.50
	07 - Distribution Plant - Electric		36760	2.60%	168,995.42	168,995.42
	07 - Distribution Plant - Electric		36910	3.90%	607.06	607.06
	08 - General Plant	Amortizable	39720	7-Year	23,287.46	23,187.33
41 - Manatee Heaters Total					**8,383,225.37**	**11,871,103.93**
42 - Turkey Point Cooling Canal Monitoring						
	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	1.80%	3,582,752.89	3,582,752.89
42 - Turkey Point Cooling Canal Monitoring Total					**3,582,752.89**	**3,582,752.89**
44 - Martin Plant Barley Barber Swamp Iron Mitigation Project						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	164,704.22	164,718.55
44 - Martin Plant Barley Barber Swamp Iron Mitigation Project Total					**164,704.22**	**164,718.55**
45 - 800MW Unit ESP Project						
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	0.00	61,517,629.25
45 - 800MW Unit ESP Project Total					**0.00**	**61,517,629.25**
Grand Total					**1,083,243,264.12**	**1,511,677,039.51**

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

Equity @ 10.00%

CAPITAL STRUCTURE AND COST RATES PER 2009 RATE CASE (a)
Docket No 080677-EI Order No PSC-10-0153-FOF-EI

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	5,298,960,654	31.565%	5.49%	1.73%	1.73%
SHORT TERM DEBT	156,113,805	0.930%	2.11%	0.02%	0.02%
PREFERRED STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER DEPOSITS	544,711,775	3.245%	5.98%	0.19%	0.19%
COMMON EQUITY	7,889,967,199	46.999%	10.00%	4.70%	7.65%
DEFERRED INCOME TAX	2,892,247,084	17.229%	0.00%	0.00%	0.00%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	5,429,401	0.032%	8.19%	0.00%	
			0		
TOTAL	$16,787,429,918	100.00%		6.65%	9.60%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (b)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$5,298,960,654	40.18%	5.49%	2.21%	2.21%
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	7,889,967,199	59.82%	10.00%	5.98%	9.74%
TOTAL	$13,188,927,853	100.00%		8.19%	11.94%
RATIO					
DEBT COMPONENTS:					
LONG TERM DEBT	1.7329%				
SHORT TERM DEBT	0.0196%				
CUSTOMER DEPOSITS	0.1940%				
TAX CREDITS -WEIGHTED	0.0007%				
TOTAL DEBT	1.9473%				
EQUITY COMPONENTS:					
PREFERRED STOCK	0.0000%				
COMMON EQUITY	4.6999%				
TAX CREDITS -WEIGHTED	0.0019%				
TOTAL EQUITY	4.7019%				
TOTAL	6.6492%				
PRE-TAX EQUITY	7.6546%				
PRE-TAX TOTAL	9.6019%				

Note:

(a) Reflects approved capital structure and ROE reflected in Docket 080677-EI which ended in Order No. PSC-10-0153-FOF-EI. The above capital structure started effective March 2010.

(b) This capital structure applies only to Convertible Investment Tax Credit (C-ITC).

Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard, Jr.
Secretary

RECEIVED
FEB 22 2011

NOTICE OF PERMIT

CERTIFIED MAIL

In the Matter of an
Application for Permit by:
Florida Power & Light Company (FP&L)
Cape Canaveral Energy Center (CCEC)
6000 N US Highway 1
Cocoa, FL 32927-6081

DEP File # FL0001473-IW1S/NR
Brevard County

Attention: David Williams, Plant Manager

Enclosed is Permit Number FL0001473 to Florida Power & Light Company (FP&L), Post Office Box 14000, Juno Beach, Florida 33408 to operate wastewater treatment and effluent disposal facilities for the Cape Canaveral Energy Center (CCEC) Unit 3 Plant located in Brevard County, Florida, issued under Section 403.0885, Florida Statutes and DEP Rule 62-620, Florida Administrative Code.

Any party to this order (permit) has the right to seek judicial review of the permit under Section 120.68, Florida Statutes, by the filing of a Notice of Appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000 and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within thirty days after this notice is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 10
PARTY Florida Power & Light Co.
DESCRIPTION R.R. Labauve (RRL-5B); Excerpt from Cape Cnaveral Plant (PCC) State IWW Permit

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Division Director
Division of Water Facilities
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8335

Florida Power & Light Company (FP&L)
Facility ID Number FL0001473

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 02-11-2011 to the listed persons.

[Clerk Stamp]

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52 (9), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

C. Shields 02-11-2011
(Clerk) (Date)

Copies furnished to:

Copies furnished by certified mail to:
Mark Nuhfer, NPDES Permitting Section, EPA Region 4, Atlanta, GA
Chairman, Board of Brevard County Commissioners

Copies furnished by First Class mail to:
Andy Flajole, FP&L
U.S. Fish & Wildlife Services
Ron Mezich, Florida Fish and Wildlife Conservation Commission (FWC)

Copies furnished by intradepartmental mail to:
Chris Ferraro, DEP Orlando
Gary Miller, DEP Orlando

Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T.
Vinyard, Jr.
Secretary

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Florida Power & Light Company (FP&L)

RESPONSIBLE OFFICIAL:
David Williams
Plant Manager
700 Universe Blvd
Juno Beach, Florida 33408

PERMIT NUMBER: FL0001473-012 (Major)
FILE NUMBER: FL0001473-012-IW1S
ISSUANCE DATE: February 11, 2011
EXPIRATION DATE: February 10, 2016

FACILITY:

Cape Canaveral Energy Center (CCEC).
6000 N US Highway 1
Cocoa, FL 32927-6081
Brevard County
Latitude: 28°28' 6.1" N Longitude: 80°45' 54.72" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.) and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. The above named permittee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:
The converted plant is named the Cape Canaveral Energy Center (CCEC). The CCEC consists of a nominal 1,250 MW natural gas-fueled combined cycle unit (Unit 3). CCEC Unit 3 consist of three nominal 250 MW combustion turbine-electrical generators, three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR), and one common nominal 500 MW steam-electrical generator. CCEC Unit 3 will use ultralow sulfur distillate fuel oil as backup fuel. .

WASTEWATER TREATMENT:
Once-through condenser cooling water and auxiliary equipment cooling water are chlorinated followed by dechlorination prior to discharge. Metal cleaning wastewater and reverse osmosis membrane cleaning wastewater will be disposed of off-site. Regeneration of mixed bed ion exchange units will be performed offsite. Plant/Equipment drains that receive washdown water from cleaning and maintenance activities are routed through an oil/water separator prior to an internal discharge to the Once-Through Cooling Water (OTCW) conduits and hence to Outfalls D-011 and D-012. When possible, Heat Recovery Steam Generator (HRSG) blowdown will be reused as make-up water to the on-site water treatment system. Alternatively, HRSG blowdown will be discharged via internal discharge to the once-through cooling water conduits and hence to Outfalls D-011 and D-012. Water treatment plant wastewater (RO reject and multimedia filter backwash) will be discharged from internal Outfall I-017 to the OTCW conduits and hence to Outfalls D-011 and D-012.

Equipment area stormwater from the power block and transformer containment areas is routed through an oil/water separator and then to a series of connected on-site retention ponds prior to discharge. The on-site retention ponds also receive some non-equipment stormwater. The stormwater management system is designed to discharge via Outfalls D-028 and D-029.

PERMITTEE: Florida Power & Light Company
FACILITY: Cape Canaveral Energy Center

PERMIT NUMBER: FL0001473-012 (Major)
ISSUANCE DATE: February 11, 2011
EXPIRATION DATE: February 10, 2016

Outfall D-028 is a shared discharge structure that regularly releases stormwater from the on-site retention ponds as well as infrequent releases of stormwater from the fuel oil storage containment area.

REUSE OR DISPOSAL:

Surface Water Discharge:

A combined plant discharge of 617 MGD annual average flow and 822 MGD maximum daily flow to the Indian River (Class II Marine waters, WBID 2963D) through two outfall structures, D-011, located approximately at latitude 28° 28' 11" N, longitude 80° 45' 46" W, and D-012, located approximately at latitude 28° 28' 14" N, longitude 80° 45' 50" W.

A stormwater discharge from the on-site retention pond system and the fuel oil storage tank secondary containment area to the Indian River (Class II Marine waters, WBID 2963D), D-028, located approximately at latitude 28° 28' 18" N, longitude 80° 45' 51" W.

A stormwater discharge from the on-site retention pond system to the Indian River (Class II Marine waters, WBID 2963D), D-029, located approximately at latitude 28° 28' 9" N, longitude 80° 45' 46" W.

A discharge of non-equipment area stormwater to the plant's intake canal (Class II Marine waters, WBID 2963D), D-024, D-025, D-026, and D-027.

Land Application:

There is no land application of wastewater at the CCEC.

INTERNAL OUTFALLS:

A discharge of plant/equipment drain wastewater from internal Outfall I-018 to the OTCW conduits and hence to Outfalls D-011 and D-012.

A discharge of water treatment plant wastewater (RO reject and multimedia filter backwash) from internal Outfall I-017 to the OTCW conduits and hence to Outfalls D-011 and D-012.

A discharge of Heat Recovery Steam Generator (HRSG) blowdown from internal Outfall I-019 to the OTCW conduits and hence to Outfalls D-011 and D-012.

A auxiliary equipment cooling water discharge of 23 MGD annual average flow and 30.0 MGD maximum daily flow from internal Outfall I-015 to the OTCW conduits and hence to Outfalls D-011 and D-012.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 26 of this permit.

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I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge the combined plant discharge (consisting of once-through and auxiliary equipment cooling water, plant/equipment drain wastewater, water treatment plant wastewater, and heat recovery steam generator blowdown) from Outfalls D-011and D-012 to Indian River Lagoon. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Instant.Maximum Monthly Average	Continuous	Calculated	FLW-1	
Chlorination Duration	min/day	Max	120	Instant. Maximum	Daily; 24 hours	Calculated	OTH-1	
Oxidants, Total Residual	mg/L	Max	0.01	Maximum Daily Average	Weekly	Grab	EFF-1 EFF-2	See I.A.3
Temp. Difference between Intake and Discharge	Deg F	Max Max Max Max	Report 14.2 Report Report	Daily Average Monthly Average Daily Average Monthly Average	6 times per day	Meter	EFF-1 EFF-2	May – Sept May – Sept Oct – Apr Oct - Apr
Temperature (F), Water	Deg F	Max Max	Report Report	Daily Average Monthly Average	6 times per day	Meter	EFF-1 EFF-2	
Oxygen, Dissolved (DO)	mg/L	Min	4.0	Single Sample	Monthly	Meter	EFF-1 or EFF-2	See I.A.5
Oxygen, Dissolved (DO)	mg/L	Max	Report	Single Sample	Monthly	Meter	INT-1	See I.A.5
Chronic Whole Effluent Toxicity, 7-Day IC25 (Mysidopsis bahia)	percent	Min	100	Single Sample	Quarterly	24-hr Composite	EFF-1 EFF-2	See I.A.4 and I.A.6
Chronic Whole Effluent Toxicity, 7-Day IC25 (Menidia beryllina)	percent	Min	100	Single Sample	Quarterly	24-hr Composite	EFF-1 EFF-2	See I.A.4 and I.A.6

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-1	Flow monitoring location for the combined discharge from Outfall D-011 and D-012.
OTH-1	At the point of chlorine addition for Unit 3 OTCW
EFF-1	End of pipe once-through cooling water discharge from Outfall D-011
EFF-2	End of pipe once-through cooling water discharge from Outfall D-012
INT-1	Once-through cooling water intake for Unit 3

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3. Grab samples shall consist of multiple samples collected at approximately the beginning, middle, and end a chlorination period. The total daily chlorination duration of 120 minutes per day may consist of multiple chlorination periods of less than 120 minutes.

4. Toxicity sampling shall consist of individual composite samples from each outfall combined in equal proportions to create a single sample for analysis.

5. Insitu dissolved oxygen monitoring for both the intake and discharge shall be performed concurrently every 4 hours, for 24 hours, once month. Monitoring during a monthly event is only required from one outfall (D-011 or D-012) but shall be alternated (between the two outfalls) every other month.

6. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from outfall D-011 and D-012.

   a. Effluent Limitation
      (1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. [Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]
      (2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. [Rules 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]

   b. Monitoring Frequency
      (1) Routine toxicity tests shall be conducted once every three months, the first starting within 60 days of the issuance date of this permit and lasting for the duration of this permit.
      (2) Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation in 6.a.(1) above, the permittee may submit a written request to the Department for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 6.a.(1) above.
      (3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-014, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive valid tests for the purpose of evaluating the reduction of monitoring frequency.

   c. Sampling Requirements
      (1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-014, Section 8.
      (2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.
      (3) Samples for routine and additional follow-up tests shall not be collected on the same day.

   d. Test Requirements
      (1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: **100%, 50%, 25%, 12.5%, and 6.25%** final effluent.
      (2) The permittee shall conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, Americamysis (Mysidopsis) bahia, Method 1007.0, and an inland silverside, Menidia beryllina, Method 1006.0, concurrently.
      (3) All test species, procedures and quality assurance criteria used shall be in accordance with Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, 3rd Edition, EPA-821-R-02-014. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In

the event the above method is revised, the permittee shall conduct chronic toxicity testing in accordance with the revised method.

(4) The control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows:

(a) For the **Americamysis bahia** bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(b) For the **Menidia beryllina** bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(c) If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements

(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.

(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-014, Section 14.12 (**Americamysis bahia**) and Section 13.12 (**Menidia beryllina**). The repeat test shall begin within 21 days after the last day of the invalid test.

(3) If 100% mortality occurs in all effluent concentrations for either species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.

(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-014, Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements

(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:

(a) Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.

(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.

(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.

(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.

(5) The same bioassay data shall not be reported as the results of more than one test.

(6) All bioassay laboratory reports shall be sent to:

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Florida Department of Environmental Protection
Tallahassee Office
2600 Blair Stone Road, M.S. 3545
Tallahassee, Florida 32399-2400

g. Test Failures
(1) A test fails when the test results do not meet the limits in 6.a.(1).
(2) Additional Follow-up Tests:
(a) If a routine test does not meet the chronic toxicity limitation in 6.a.(1) above, the permittee shall notify the Department at the address above within 21 days after the last day of the failed routine test and conduct two additional follow-up tests on each species that failed the test in accordance with 6.d.
(b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.
(c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permittee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-014.
(3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permittee shall notify the Department within 21 days after the last day of the third test failure.
(a) The permittee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.
(b) The Department shall review and approve the plan before initiation.
(c) The plan shall be initiated within 30 days following the Department's written approval of the plan.
(d) Progress reports shall be submitted quarterly to the Department at the address above.
(e) During the implementation of the plan, the permittee shall conduct quarterly routine whole effluent toxicity tests in accordance with 6.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 6.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-014, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.
(f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 6.a.(1) above, the permittee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests. If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.
(4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 6.(a)(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.
(5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

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7. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

8. Discharges from Outfalls D-011 and D-012 are subject to thermal limitations established by Rule 62-302.520(1), F.A.C.

9. OTCW and AECW limitations and monitoring requirements for TRO are not applicable for any week in which chlorine is not added to Unit 3.

B. **Internal Outfalls**

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Water Treatment Plant Wastewater** from I-017 to the OTCW conduits and hence to Outfalls D-011 and D-012. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Average Monthly Average	2/month	Calculated	OUI-1	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Average	2/month	Composite	OUI-1	See I.B.3
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Average	2/month	Grab	OUI-1	
pH	s.u.	Min Max	6.0 9.0	Instant. Minimum Instant.Maximum	2/month	Grab	OUI-1	
Nitrogen, Total	mg/l	-	Report	Single Sample	Monthly	8-hr Composite	OUI-1	
Nitrogen, Total, Monthly Loading	lbs/month	-	Report	Total Monthly	Monthly	Calculated	OUI-1	
Nitrogen, Total, Annual Loading	lbs/year	Max	2555	Total Annual (Calendar year)	Annual (Calendar year)	Calculated	OUI-1	See I.B.4
Phosphorous, Total	mg/l	-	Report	Single Sample	Monthly	8-hr Composite	OUI-1	
Phosphorous, Total, Monthly Loading	lbs/month	-	Report	Total Monthly	Monthly	Calculated	OUI-1	
Phosphorous, Total, Annual Loading	lbs/year	Max	146	Total Annual (Calendar year)	Annual (Calendar year)	Calculated	OUI-1	See I.B.5

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
OUI-1	At the point of discharge to the OTCW conduits and prior to mixing with any other wastewater stream.

3. The composite sample shall be consists of grab samples taken at the beginning, middle and end of the Backwash Basin discharge period.

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4. The calendar year total nitrogen loading shall be the summation of each of the twelve monthly nitrogen loadings during the calendar year.

5. The calendar year total phosphorous loading shall be the summation of each of the twelve monthly phosphorous loadings during the calendar year

6. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Plant/Equipment Drain Wastewater** from I-018 to OTCW conduits and hence to Outfalls D-011 and D-012. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Average Monthly Average	Monthly	Calculated	OUI-2	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Average	Monthly	Grab	OUI-2	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Average	Monthly	Grab	OUI-2	
pH	s.u.	Min Max	6.0 9.0	Instant. Minimum Instant. Maximum	Monthly	Grab	OUI-2	

7. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.6 and as described below:

Monitoring Site Number	Description of Monitoring Site
OUI-2	At the point of discharge to the OTCW conduits

8. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Heat Recovery Steam Generator (HRSG) Blowdown** from I-019 to the OTCW conduits and hence to Outfalls D-011 and D-012. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Average Monthly Average	Monthly	Calculated	OUI-3	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Average	Monthly	Grab	OUI-3	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Average	Monthly	Grab	OUI-3	

9. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.8. and as described below:

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Monitoring Site Number	Description of Monitoring Site
OUI-3	At the point of discharge to the OTCW conduits

10. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Auxiliary Equipment Cooling Water** from Outfall I-015 to the OTCW conduits and hence to Outfalls D-011 and D-012. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Average Monthly Average	Continuous	Calculated	FLW-2	
Chlorination Duration	min/day	Max	1440	Instant. Maximum	Daily; 24 hours	Calculated	OTH-2	

11. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.7. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-2	Flow monitoring location for auxiliary equipment cooling water for Unit 3
OTH-2	At the point of chlorine addition for Unit 3 AECW

12. During the period beginning at initiation of discharge and lasting through the expiration date of this permit, the permittee is authorized to discharge from Outfall D-028, stormwater from the fuel oil storage tank secondary containment area, provided such discharges are limited and monitored by the permittee as specified below:

a. The facility shall have a valid Spill Prevention Control and Countermeasure (SPCC) Plan pursuant to 40 CFR Part 112.

b. The facility shall endeavor to retain the stormwater in the containment area to the maximum extent practicable before discharging from Outfall D-028. The discharge from Outfall D-028 shall only occur due to tank and equipment integrity and safety concerns.

c. In draining the diked area, a portable oil skimmer or similar device or absorbent material shall be used to remove oil and grease (as indicated by the presence of a sheen) immediately prior to draining.

d. Monitoring records shall be maintained in the form of a log and shall contain the following information, as a minimum:

- Date and time of discharge;
- Estimated volume of discharge;
- Initials of person making visual inspection and authorizing discharge; and
- Observed conditions of storm water discharged.

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e. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of a visible oil sheen at any time.

C. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in 62-302, F.A.C.; and

   c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

   When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

   Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

3. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e. monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	Due Date
Monthly or Toxicity	first day of month - last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 - June 30 July 1 - September 30 October 1 - December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 - June 30	July 28

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	July 1 - December 30	January 28
Annual	January 1 - December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge. The permittee may submit either paper or electronic DMR form(s). If submitting paper DMR form(s), the permittee shall make copies of the attached DMR form(s). If submitting electronic DMR form(s), the permittee shall use a Department-approved electronic DMR system.

The electronic submission of DMR forms shall be accepted only if approved in writing by the Department. For purposes of determining compliance with this permit, data submitted in electronic format is legally equivalent to data submitted on signed and certified paper DMR forms.

The permittee shall submit the completed DMR form(s) to the Department by the twenty-eighth (28th) of the month following the month of operation at the addresses specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

And

Florida Department of Environmental Protection
Central District Office
3319 Maguire Boulevard Suite 232
Orlando, Florida 32803-3767
Phone Number - (407) 894-7555

[62-620.610(18)]

4. The permittee shall not submit DMR forms that alter the original format or content of the attached DMR forms without written approval from the Department's Central District Office at the address specified below:

   Florida Department of Environmental Protection
   Central District Office
   3319 Maguire Boulevard Suite 232
   Orlando, Florida 32803-3767
   Phone Number - (407) 894-7555

5. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Central District Office at the address specified above.All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. *[62-620.305]*

6. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

7. The Permittee shall develop a Plan of Study (POS), subject to Department review and approval, to monitor compliance with Rule 62-302.520(1), F.A.C. pursuant to the schedule in Item VI.4, including a proposed implementation schedule, designed to determine any effects on biological communities from the discharge to Indian River Lagoon. The plan shall include biological sampling prior to start-up of the CCEC Unit 3 in order to establish baseline biological conditions within the receiving waters. The plan shall address monitoring of aquatic species as necessary, including frequency of sampling. The POS shall incorporate relevant existing data

developed by the Permittee and other sources as well as any necessary additional monitoring to be conducted by the Permittee.

8. The permittee shall develop a plan in accordance with the schedule in Condition VI.3 to return live fish, shellfish, and other aquatic organisms collected or trapped on the plant intake screens to their natural habitat. Other material shall be removed from the intake screens and disposed of in accordance with all existing Federal, State and /or local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters.

9. The permittee shall maintain plant intake traveling screen practices so as to assure that the screens are cycled at least twice during each 24 hours of continuous operation unless precluded by repair or maintenance requirements.

10. The plant intake through-screen velocity shall be maintained at or below levels that existed prior to plant conversion.

11. During the period beginning at initiation of discharge and lasting through the expiration date of this permit, the permittee is authorized to discharge non-equipment area stormwater from Outfalls D-024, D-025, D-026, D-027 and D-029 without limitation or monitoring requirements.

12. Intake Screen wash water may be discharged without limitation or monitoring requirements, except that there shall be no discharge of a visible sheen.

13. The Permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on December 21, 2000.

14. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit.

    The company shall notify the Department in writing no later than six (6) months prior to instituting use of any biocide or chemical (except chlorine as authorized elsewhere in this permit) used in the cooling systems or any other portion of the treatment system which may be toxic to aquatic life. Such notification shall include:

    a. Name and general composition of biocide or chemical

    b. Frequencies of use

    c. Quantities to be used

    d. Proposed effluent concentrations

    e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)

    f. Product data sheet

    g. Product label

    The Department shall review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without a permit revision by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

PERMITTEE: Florida Power & Light Company
FACILITY: Cape Canaveral Energy Center

PERMIT NUMBER: FL0001473-012 (Major)
ISSUANCE DATE: February 11, 2011
EXPIRATION DATE: February 10, 2016

II. SLUDGE MANAGEMENT REQUIREMENTS

1. The permittee shall be responsible for proper treatment, management, use, and disposal of its sludges. *[62-620.320(6)]*

2. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in accordance with requirements of Chapter 62-730, F.A.C. *[62-730]*

3. Vegetation and materials removed from intake screens and vegetation, sediments and sludge excavated from the settling basins and percolation basins must be properly stored onsite until they are disposed in accordance with requirements in Chapter 62-701, F.A.C., and other applicable State and Federal requirements.Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in accordance with requirements of Chapter 62-730, F.A.C. *[62-730]*

III. GROUND WATER REQUIREMENTS

1. There are no ground water monitoring requirements included in this permit. Ground water monitoring requirements for this facility are included in the Condition of Certification PA 08-53.

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

1. There are no land application discharges at this facility.

V. CONSTRUCTION, OPERATION AND MAINTENANCE REQUIREMENTS

A. General Operation and Maintenance Requirements

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports required by the permit for at least three years from the date the report was prepared;

   c. Records of all data, including reports and documents, used to complete the application for the permit for at least three years from the date the application was filed;

   d. Records of all disposal of vegetation and materials removed from intake screens and vegetation, sediments and sludge removed from wastewater and stormwater basins

   e. A copy of the current permit;

   f. A copy of any required record drawings; and

   g. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules.

   [62-620.350]

PERMITTEE: Florida Power & Light Company
FACILITY: Cape Canaveral Energy Center

PERMIT NUMBER: FL0001473-012 (Major)
ISSUANCE DATE: February 11, 2011
EXPIRATION DATE: February 10, 2016

B. Storm Water Requirements

1. The permittee shall amend the SWPPP whenever there is a change at the facility or change in the operation of the facility that materially increases the potential for the ancillary activities to result in a discharge of additional, significant amounts of pollutants. The permittee shall have 30 days after facility or operational changes to update the SWPPP as necessary.

VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule. The Storm Water Pollution Prevention Plan (SWPPP) shall be prepared and implemented in accordance with Part VII of this permit.

Improvement Action	Completion Date
1. Develop and implement SWPPP	18 months from commercial operation
2. Complete Plan Summary	2 years from commercial operation
3. Progress/Update Report	3 years, and then annual thereafter

2. If the permittee wishes to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C. *[62-620.335(1) and (2)*

3. Within 3 months from the issuance date of this permit, the permittee shall schedule a meeting with the Department to discuss the contents of the aquatic organism return plan in accordance with Condition I.C.8 and shall submit the plan to the Department within 6 months thereafter. The plan shall be implemented upon start-up of the CCEC Unit 3.

4. Within 3 months of issuance of this permit, the Permittee shall meet with the Department to discuss the content of a Plan of Study (POS) for biological monitoring in accordance with the requirements of Item I.C.7, and shall submit the POS within 6 months of issuance of this permit. The Department will review the POS and provide written comments to the permittee as needed. The permittee shall implement the POS in accordance with the approved implementation schedule.

5. The permittee shall submit a copy of the Manatee Protection Plan, including any amendments, with the permit renewal application to each of the following agencies no later than one-hundred and eighty days (180) prior to the expiration date of this permit:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Florida Fish and Wildlife Conservation Commission
Bureau of Protected Species Management
620 South Meridian Street
OES-BPS
Tallahassee, Florida 32399-1600

And

PERMITTEE: Florida Power & Light Company
FACILITY: Cape Canaveral Energy Center

PERMIT NUMBER: FL0001473-012 (Major)
ISSUANCE DATE: February 11, 2011
EXPIRATION DATE: February 10, 2016

US Fish and Wildlife Service
Jacksonville Field Office
7915 Baymeadows Way, Suite 200
Jacksonville, Florida 32256-7517

VII. STORMWATER POLLUTION PREVENTION PLANS

1. General Requirements

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Storm Water Management Industrial Activities Guidance Manual, EPA/833-R92-002 and other EPA documents relating to Best Management Practice guidance.

a. Definitions
   (1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.
   (2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.
   (3) Non-conventional pollutants are those which are not defined as conventional or toxic.
   (4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.
   (5) "Significant Materials" is defined as raw materials; fuels; materials such as solvents and detergents; hazardous substances designated under Section 101(14) of CERCLA; and any chemical the facility is required to report pursuant to EPCRA, Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge.
   (6) "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.
   (7) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.
   (8) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.
   (9) "SWPPP" means a Storm Water Pollution Prevention Plan incorporating the requirements of 40 CFR § 125, Subpart K, plus pollution prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.
   (10) The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

2. Storm Water Pollution Prevention Plan

PERMITTEE:	Florida Power & Light Company	PERMIT NUMBER:	FL0001473-012 (Major)
FACILITY:	Cape Canaveral Energy Center	ISSUANCE DATE:	February 11, 2011
		EXPIRATION DATE:	February 10, 2016

The permittee shall develop and implement a SWPPP for the facility, which is the source of wastewater and storm water discharges, covered by this permit. The plan shall be directed toward reducing those pollutants of concern which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities.

a. Signatory Authority & Management Responsibilities

The SWPPP shall be signed by permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The SWPPP shall be reviewed by plant environmental/engineering staff and plant manager. Where required by Chapter 471-(P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of the SWPPP shall be signed and sealed by the professional(s) who prepared them.

A copy of the plan shall be retained at the facility and shall be made available to the permit issuing authority upon request.

The SWPPP shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the SWPPP. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the SWPPP.

b. SWPPP Requirements

(1) A topographic map extending one-quarter mile beyond the property boundaries of the facility, showing: the facility, surface water bodies, wells (including injection wells), seepage pits, infiltration ponds, and the discharge points where the facility's storm water discharges to a municipal storm drain system or other water body. The requirements of this paragraph may be included on the site map if appropriate.

(2) A site map showing:

(a) The storm water conveyance and discharge structures;

(b) An outline of the storm water drainage areas for each storm water discharge point;

(c) Paved areas and buildings;

(d) Areas used for outdoor manufacturing, storage, or disposal of significant materials, including activities that generate significant quantities of dust or particulates;

(e) Location of existing or future storm water structural control measures/practices (dikes, coverings, detention facilities, etc.);

(f) Surface water locations and/or municipal storm drain locations;

(g) Areas of existing and potential soil erosion;

(h) Vehicle service areas;

(i) Material loading, unloading, and access areas;

(3) A narrative description of the following:

(a) The nature of the industrial activities conducted at the site, including a description of significant materials that are treated, stored or disposed of in a manner to allow exposure to storm water;

(b) Materials, equipment, and vehicle management practices employed to minimize contact of significant materials with storm water discharges;

(c) Existing or future structural and non-structural control measures/practices to reduce pollutants in storm water discharges;

(d) Industrial storm water discharge treatment facilities;

(e) Methods of onsite storage and disposal of significant materials;

(f) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;

(g) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;

(h) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and

2. The description of a waste minimization assessment performed in accordance with the conditions outlined in condition c below, results of the assessment, and a schedule for implementation of specific waste reduction practices.

(4) A list of the types of pollutants that have a reasonable potential to be present in storm water discharges in significant quantities.

(5) An estimate of the size of the facility in acres or square feet, and the percent of the facility that has impervious areas such as pavement or buildings.

(6) A summary of existing sampling data describing pollutants in storm water discharges.

c. Waste Minimization Assessment

The permittee is encouraged but not required to conduct a waste minimization assessment (WMA) for this facility to determine actions that could be taken to reduce waste loading and chemical losses to all wastewater and/or storm water streams as described in Part VII.D.2 of this permit.

If the permittee elects to develop and implement a WMA, information on plan components can be obtained forms the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8589
(850) 245-8669 – Fax

d. Pollution Prevention Committee:

A pollution prevention committee within the plant organization shall be appointed. These members shall be responsible for developing the SWPPP and assisting the plant manager in its implementation, maintenance, and revision.

e. Employee Training

(1) The permittee shall describe the storm water employee training program for the facility. The description shall include the topics to be covered, such as spill response, good housekeeping and material management practices, and shall identify periodic dates (e.g., every 6 months during the months of July and January) for such training. The permittee shall provide employee training for all employees and contractors that work in areas where industrial materials or activities are exposed to storm water, and for employees that are responsible for implementing activities identified in the SWPPP (*e.g.*, inspectors, maintenance people). The employee training shall inform facility personnel and contractors of the components and goals of the facility SWPPP.

PERMITTEE: Florida Power & Light Company
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(2) Each employee and contractor that works in an areas where industrial materials or activities are exposed to storm water, and each employee that is responsible for implementing activities identified in the SWPPP shall undergo training at least once a year. Training records shall include trainee's name, signature, date of training and topics covered. Records shall be retained on-site for a minimum of three years.

f. Plan Development & Implementation

(1) The SWPPP shall be developed and implemented 18 months after the effective date of this permit, unless any later dates are specified in this permit. Any portion of the SWPPP which is ongoing at the time of development or implementation shall be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time shall be identified in the plan, including a schedule for its implementation.

(2) The personnel named in the SWPPP shall perform and document a quarterly visual observation of a storm water discharge associated with industrial activity from each outfall. The visual observation shall be made during daylight hours. If no storm event resulted in runoff during daylight hours from the facility during a monitoring quarter, the permittee is excused from the visual observation requirement for that quarter, provided the permittee documents in their records that no runoff occurred. The permittee shall sign and certify the documentation.

(3) The personnel named in the SWPPP shall conduct visual observations on samples collected as soon as practical, but not to exceed 1 hour of when the runoff begins discharging from the facility. All samples must be collected from a storm event discharge that is greater than 0.1 inch in magnitude and that occurs at least 72 hours from the previously measurable (greater than 0.1 inch rainfall) storm event. The observation shall document: color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution.

(4) The permittee shall maintain visual observation reports onsite with the SWPPP for a minimum of three years. The report must include the observation date and time, inspection personnel, nature of the discharge (i.e., runoff), visual quality of the storm water discharge (including observations of color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution), and probable sources of any observed storm water contamination.

(5) At least once a year the personnel named in the SWPPP shall verify that the description of potential pollutant sources required under this permit is accurate; the site map as required in the SWPPP has been updated or otherwise modified to reflect current conditions; and the controls to reduce pollutants in storm water discharges associated with industrial activity identified in the SWPPP are being implemented and are adequate.

g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the SWPPP shall be developed and maintained at the facility and made available to the permit issuing authority upon request. The summary should include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction practices being employed at the facility. The results of waste minimization assessment studies already completed as well as any scheduled or ongoing WMA studies shall be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the permit issuing authority upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of

any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices shall be included.

(3) A timetable for the various plan requirements follows:

Timetable for SWPPP Requirements:

REQUIREMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Complete SWPPP	18 months
Complete Plan Summary	2 years
Progress/Update Reports	3 years, and then annually thereafter

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the SWPPP is determined insufficient, the permittee will be notified that the SWPPP does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

The permittee shall modify the SWPPP whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.

The permittee may incorporate applicable portions of plans prepared for other purposes. Plans or portions of plans incorporated into a SWPPP become enforceable requirements of this permit.

VIII. OTHER SPECIFIC CONDITIONS

A. Specific Conditions Applicable to All Permits

1. Where required by Chapter 471 or Chapter 492, F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a professional engineer or a professional geologist, as appropriate. *[62-620.310(4)]*

2. The permittee shall provide verbal notice to the Department's Central District Office as soon as practical after discovery of a sinkhole or other karst feature within an area for the management or application of wastewater, or wastewater sludges. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department's Central District Office in a written report within 7 days of the sinkhole discovery. *[62-620.320(6)]*

B. Duty to Reapply

1. The permittee is not authorized to discharge to waters of the State after the expiration date of this permit, unless:

a. the permittee has applied for renewal of this permit at least 180 days before the permit expiration date using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in the Department of

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	**EXHIBIT**	11
PARTY	Florida Power & Light Co.		
DESCRIPTION	R.R. LaBauve (RRL-6), Excerpt from Riviera Plant (PRV)NPDES Permit		

Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by:

Mr. Mark Lemasney
Plant General Manager
Florida Power & Light Company
200-300 Broadway
Rivera, Florida 33404

PA File No. FL0001546-006-IW1S
Palm Beach County
Riviera Power Plant
NPDES Permit No. FL0001546

NOTICE OF PERMIT ISSUANCE

Enclosed is Permit Number FL0001538 to Florida Power & Light Company, authorizing wastewater discharge from the Riviera Power Plant to the Intracoastal Waterway (Lake Worth), a Class III marine water, issued under Section 403.0885, Florida Statutes, and DEP Rule 62-620, Florida Administrative Code.

The plant is scheduled to undergo modernization between 2011 and 2014. The modernization project includes the construction of a nominal 1,250 megawatt natural gas-fired combined cycle unit system ("3-on-1") designated as Unit 5. In addition, this project includes the permanent shutdown of Units 3 and 4. RBEC Unit 5 is projected to be operational in June 2014. RBEC Unit 5 uses the existing once-through cooling water system and Outfalls D-013 and D-014 servicing Units 3 and 4. This permit revision does not authorize an increase in the quantity or a change in the quality of the wastewater discharges to Lake Worth Lagoon a Class III Marine Water.

Any party to this order (permit) has the right to seek judicial review of the permit action under Section 120.68, Florida Statutes, by the filing of a notice of appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when this document is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mark P. Thomasson, P.E.
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

FACILITY: Rivera Power Plant
PERMITTEE: Florida Power & Light Company

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52, Florida Statutes, with the designated deputy clerk, receipt of which is hereby acknowledged.

G. Shields 08-17-2011
Clerk Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this DOCUMENT AND ATTACHMENTS and all copies were mailed before the close of business on 08-17-2011 to the listed persons.

Shirley Shields 08-17-2011
Name Date

Certified copies furnished to:
Mark Nuhfer, NPDES Permitting Section, EPA Region 4, Atlanta, GA
Chairman, Board of Broward County Commissioners

Copies furnished by First Class mail to:
Florida Fish and Wildlife Conservation Commission, Conservation Planning Services
U.S. Fish & Wildlife Service
Andy Flajole, Florida Power and Light

Copies furnished by intradepartmental mail to:
Linda Brien, P.G., DEP West Palm Beach
John Armstrong, P.E., DEP West Palm Beach
Michael Hambor, DEP West Palm Beach
Cindy Mulkey, DEP Tallahassee

SECOND AMENDMENT TO THE FACT SHEET

DATE: August 10, 2011

PERMIT NUMBER: FL0001546

PERMITTEE: Florida Power & Light
Riviera Beach Energy Complex

The following minor corrections and revisions have been made to the proposed permit. None of these corrections alter any of the limitations for discharge to water of the state.

1. **Typographical Errors in the Proposed Permit**

   The Department and the Permittee noted several typographical errors which are not listed in the items below. The Department has corrected these errors, which were non-substantive and did not affect any permit limitations or monitoring requirements.

2. **Comments by the Permittee Requesting Changes to the Proposed Permit**

   Page 1, Facility Description. The permittee requested that the facility description be revised to clarify the piping assembly for the once-through cooling water discharge from Outfall D-013. The Department concurred and the description was revised.

   Page 13, VI.3. The permittee requested that the schedule for the aquatic organism return system be revised to be consistent with the language in the Amendment to the Factsheet issued with the Notice of Intent for this revision. The Department concurred.

3. **Other Comments**

   No comments were received from the public or from other governmental agencies.

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITEE:
Florida Power & Light Company (FPL)

PERMIT NUMBER: FL0001546 (Major) Rev. A
FILE NUMBER: FL0001546-006-IW1S

ISSUANCE DATE: August 28, 2010
REVISION DATE: August 19, 2011
EXPIRATION DATE: August 27, 2015

RESPONSIBLE OFFICIAL:
Mr. Mark Lemasney
Plant Manager
200-300 Broadway
Riviera Beach, Florida 33404

FACILITY:

Riviera Beach Energy Center (RBEC)
200-300 Broadway
Riviera Beach, FL 33404
Palm Beach County
Latitude: 26°45'51.9" N Longitude: 80°03' 9.89" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.) and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. The above named permitee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:
The facility is an electric generating plant with a total nameplate rating of 1250 megawatts (MW). RBEC consists of a combined cycle unit system, designated as Unit 5. Unit 5 consists of three gas turbines. Exhaust from each gas turbine passes through a separate supplementary gas fired heat recovery steam generator (HRSG). Steam from each HRSG is delivered to a single steam turbine-electrical generator. Unit5 is capable of burning a variable combination of natural gas and No. 2 ultralow sulfur distillate fuel oil as a backup fuel oil.

Unit 5 has condenser once-through cooling water (OTCW) and auxiliary equipment cooling water (AECW) systems that use water from Lake Worth Lagoon, a coastal marine water body. AECW and other Unit 5 wastewater streams comingle with the OTCW. The OTCW passes a seal well overflow structure (a structure that works as a dampener for the discharge). The majority of the combined OTCW and AECW flows are discharged through two submerged pipelines, approximately 2,000 feet in length that extend into the Lake Worth Lagoon. The ends of those pipes are located approximately at latitude 26°45' 52" N, longitude 80° 02' 21" W. The remaining portion of the OTCW is discharged to the facility's shoreline embayment to provide a warm-water refugia for West Indian Manatees pursuant to the facility's Manatee Protection Plan."

Unit 5 is also regulated under the Florida Electrical Power Plant Siting Act (License No. PA09-54).

WASTEWATER TREATMENT:
Once-through condenser cooling water and auxiliary equipment cooling water are chlorinated followed by dechlorination prior to discharge. OTCW is discharged via Outfall D-013. AECW is discharged via internal outfall I-015 to the OTCW conduits and hence to Outfall D-013. Metal cleaning wastewater and reverse osmosis membrane cleaning wastewater will be disposed of off-site. Regeneration of mixed bed ion exchange units will be performed off-site.

Plant/equipment drains that receive wash down water from cleaning and maintenance activities are routed through an oil/water separator prior to discharge via internal outfall I-016 to the OTCW conduits and hence to Outfall D-013. Water treatment plant wastewater (including Reverse Osmosis (RO) reject, softener, multimedia filter backwash, low-volume and metal cleaning wastewater) will be discharged from internal Outfall I-017 to the OTCW conduits and hence to Outfall D-013. When possible, Heat Recovery Steam Generator (HRSG) and Evaporative Cooler blowdown will be reused as make-up water

PERMITEE: Florida Power & Light Company
FACILITY: Riviera Beach Energy Center

PERMIT NUMBER: FL0001546 (Major) Rev. A
EXPIRATION DATE: August 27, 2015

to the on-site water treatment system. Alternatively, the combined blowdown will be discharged from internal outfall I-018 to the OTCW conduits and hence to Outfall D-013.

Equipment area storm water from the power block and transformer containment areas is routed through an oil/water separator and then to a series of connected on-site retention ponds (that also receive non-equipment area storm water) prior to discharge. Storm water discharges from RBECare authorized under the State-issued Water Multi-Sector General Permits for stormwater associated with Industrial Activities (MSGPs)

EFFLUENT DISPOSAL:

Surface Water Discharge D-009: An existing permitted discharge to Intracoastal Waterway, Class III Marine Waters (WBID 3226E1). The point of discharge is located approximately at 26° 45' 55" N, longitude 80° 03' 03" W.

Surface Water Discharge D-012/D-182: An existing permitted outfall to Intracoastal Waterway, Class III Marine Waters (WBID 3226E1). The point of discharge is located approximately at latitude 26°45' 50 N, longitude 80°03' 03" W.

Surface Water Discharge D-013: An existing permitted discharge to Intracoastal Waterway, Class III Marine Waters (WBID 3226E1). The point of discharge is located approximately at latitude 26°45' 52" N, longitude 80° 02 40" W (seal well lat and long needed).

Internal Outfall I-015: A permitted discharge of auxiliary equipment cooling water leading to the OTCW conduits and hence to Outfall D-013. The point of discharge is located approximately at latitude 26°45' 52" N, longitude 80° 03' 40" W.

Internal Outfall I-016: A permitted discharge of plant/equipment drain wastewater leading to the OTCW conduits and hence to Outfall D-013. The point of discharge is located approximately at latitude 26°45' 52" N, longitude 80° 03' 40" W.

Internal Outfall I-017: A permitted discharge of water treatment plant wastewater leading to the OTCW conduits and hence to Outfall D-013. The point of discharge is located approximately at latitude 26°45' 52" N, longitude 80° 03' 40" W.

Internal Outfall I-018: A permitted discharge of HRSG blowdown leading to the OTCW conduits and hence to Outfall D-013. The point of discharge is located approximately at latitude 26°45' 52" N, longitude 80° 03' 40" W.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 20 of this permit.

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I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Discharges

1. The permitee shall not discharge from Outfall D-012/D-182 without written approval from the Department.

2. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permitee is authorized to discharge the combined plant discharge (consisting of once-through and auxiliary equipment cooling water, plant/equipment drain wastewater, water treatment plant wastewater, and HRSG/evaporative cooler blowdown) from Outfall D-013 to two submerged pipelines approximately 2, 000 feet in length and the shoreline embayment. Such discharge shall be limited and monitored by the permitee as specified below and reported in accordance with Permit Condition I.C.3:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Instant. Maximum Monthly Average	Continuous	Calculated	FLW-1	
Chlorination Duration	min/day	Max	120	Instant. Maximum	Daily; 24 hours	Calculated	OTH-1	See I.A.4
Oxidants, Total Residual	mg/L	Max Max	0.01 0.01	Daily Maximum Monthly Average	Weekly	Grab	EFF-1	See I.A.5
Temp. Difference between Intake and Discharge	Deg F	Max Max	Report Report	Daily Average Monthly Average	6 times per day	Meter	EFF-1 INT-1	
Temperature, Water	Deg F	Max Max	Report Report	Daily Average Monthly Average	6 times per day	Meter	EFF-1	
Copper, Total Recoverable	ug/L	Max Max	3.7 3.7	Daily Maximum Monthly Average	Monthly	24-hr FPC	EFF-1	See I.A.6
		Max Max	Report Report	Daily Maximum Monthly Average			INT-1	
Iron, Total Recoverable	mg/L	Max Max	0.3 0.3	Daily Maximum Monthly Average	Monthly	24-hr FPC	EFF-1	See I.A.6
		Max Max	Report Report	Daily Maximum Monthly Average			INT-1	
Thallium, Total Recoverable	ug/L	Max Max	6.3 6.3	Daily Maximum Monthly Average	Monthly	24-hr FPC	EFF-1	See I.A.6
		Max Max	Report Report	Daily Maximum Monthly Average			INT-1	
Chronic Whole Effluent Toxicity, 7-Day IC25 (Americamysis bahia)	percent	Min	100	Single Sample	Quarterly	24-hr Composite	EFF-1 EFF-2	See I.A.7
Chronic Whole Effluent Toxicity, 7-Day IC25 (Menidia beryllina)	percent	Min	100	Single Sample	Quarterly	24-hr Composite	EFF-1	See I.A.7

3. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.2. and as described below:

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Monitoring Site Number	Description of Monitoring Site
FLW-1	Calculated flow for the combined discharge from Outfall D-013.
OTH-1	At the point of chlorine addition for Unit 5 OTCW
EFF-1	At the seal well overflow structure for Outfall D-013
INT-1	Once-through cooling water intake for Unit 5

4. Sodium hypochlorite and gaseous chlorine may be used as a biocide in the cooling water systems for Unit 5. No other biocide shall be used without explicit approval from the Department (see Permit Condition I.C.9).

5. Total Residual Oxidants (TRO) means the value obtained using the amperometric titration method for total residual chlorine or the Hach model 19300 (or equivalent). Testing for TRO by titration shall be conducted according to either the low-level amperometric method, or the DPD calorimetric method as specified in section 4500-CI E. or 4500 CI G., respectively, Standard Methods for the examination of Water and Waste water, 18th Edition (or most current edition).

   The permitee shall collect samples weekly when chlorine is in use. TRO monitoring requirements for Unit 5 are not applicable for any week in which chlorine is not added.

   Multiple grabs for TRO shall be defined as once per five minutes during TRO discharge periods of 30 minutes or less and once per 15 minutes for periods exceeding 30 minutes with no less than four analyses during the period of TRO discharge (sampling shall be continued until the end of the TRO discharge).

6. The limits for Total Recoverable Copper, Iron, and Thallium shall be the water quality standards set forth in Rule 62-302.530, F.A.C., for Class III waters as specified here or the concentration of the intake cooling water, whichever is greater. If the Outfall D-013composite sample exceeds the water quality standard concentration the Permitee shall analyze and report the intake concentration. The intake composite sample shall be collected on the same day as those for Outfall D-013. The intake composite samples shall be preserved and stored in accordance with DEP SOPs. If the intake concentration exceeds the water quality standard and the Outfall D-013 composite samples is less than or equal to the intake concentration, the facility shall be in compliance with the limitation. If both the intake concentration exceeds the water quality standard and the Outfall D-013composite sample exceeds the intake concentration, the concentration of a minimum of five (5) additional subsamples shall be analyzed from the original intake and outfall composites. The results shall be evaluated using the "student's t-test" comparing discharge concentrations with the intake concentrations. Unless the discharge concentration exceeds the intake concentration at the 95% confidence level, the facility shall be in compliance with the limitation.

7. The permitee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from outfall D-013.

   a. Effluent Limitation
      (1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. [Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]
      (2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. [Rules 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]

   b. Monitoring Frequency
      (1) Routine toxicity tests shall be conducted once every three months, the first day of the second month following the commercial operation date of RBEC and lasting for the duration of this permit.
      (2) Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation in 7.a.(1) above, the permitee may submit a written request to the Department for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective

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upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 7.a.(1) above.

(3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-014, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive valid tests for the purpose of evaluating the reduction of monitoring frequency.

c. Sampling Requirements

(1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-014, Section 8.

(2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.

(3) Samples for routine and additional follow-up tests shall not be collected on the same day.

d. Test Requirements

(1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: **100%, 50%, 25%, 12.5%**, and **6.25%** final effluent.

(2) The permitee shall conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, **Americamysis bahia**, Method 1007.0, and an inland silverside, **Menidia beryllina**, Method 1006.0, concurrently.

(3) All test species, procedures and quality assurance criteria used shall be in accordance with **Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms**, 3rd Edition, EPA-821-R-02-014. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In the event the above method is revised, the permitee shall conduct chronic toxicity testing in accordance with the revised method.

(4) The control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows:

(a) For the **Americamysis bahia** bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(b) For the **Menidia beryllina** bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(c) If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements

(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.

(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-014, Section 14.12 (**Americamysis bahia**) and Section 13.12 (**Menidia beryllina**). The repeat test shall begin within 21 days after the last day of the invalid test.

(3) If 100% mortality occurs in all effluent concentrations for either species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.

(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-014, Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements

(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:

(a) Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.

(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.

(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.

(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.

(5) The same bioassay data shall not be reported as the results of more than one test.

(6) All bioassay laboratory reports shall be sent to:
Florida Department of Environmental Protection
Tallahassee Office
2600 Blair Stone Road, M.S. 3545
Tallahassee, Florida 32399-2400

g. Test Failures

(1) A test fails when the test results do not meet the limits in 7.a.(1).

(2) Additional Follow-up Tests:

(a) If a routine test does not meet the chronic toxicity limitation in 7.a.(1) above, the permitee shall notify the Department at the address above within 21 days after the last day of the failed routine test and conduct two additional follow-up tests on each species that failed the test in accordance with 7.d.

(b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.

(c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permitee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-014.

(3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permitee shall notify the Department within 21 days after the last day of the third test failure.

(a) The permitee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.

(b) The Department shall review and approve the plan before initiation.

(c) The plan shall be initiated within 30 days following the Department's written approval of the plan.

(d) Progress reports shall be submitted quarterly to the Department at the address above.

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(e) During the implementation of the plan, the permitee shall conduct quarterly routine whole effluent toxicity tests in accordance with 7.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 7.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-014, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.

(f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 7.a.(1) above, the permitee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests. If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.

(4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 7.(a)(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.

(5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

8. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

9. Discharges from Outfall D-013 are subject to thermal limitations established by Rule 62-302.520(1), F.A.C.

10. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge intake screen wash water from Outfall D-009. Discharge of intake screen wash water is permitted without limitation or monitoring requirements.

B. Internal Outfalls

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permitee is authorized to discharge **Auxiliary Equipment Cooling Water** from Outfall I-015 to the OTCW conduits and hence to Outfall D-013. Such discharge shall be limited and monitored by the permitee as specified below and reported in accordance with Permit Condition I.C.3:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Continuous	Calculated	FLW-2	
Chlorination Duration	min/day	Max	1440	Instant. Maximum	Daily; 24 hours	Calculated	OUI-1	

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1. and as described below:

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Monitoring Site Number	Description of Monitoring Site
FLW-2	Flow calculation for auxiliary equipment cooling water for Unit 5
OUI-1	At the point of chlorine addition for Unit 5 AECW

3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permitee is authorized to discharge **Plant/Equipment Drain Wastewater** from I-016 to OTCW conduits and hence to Outfall D-013. Such discharge shall be limited and monitored by the permitee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Monthly	Calculated	FLW-3	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Monthly	Grab	OUI-2	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Monthly	Grab	OUI-2	
pH	s.u.	Min Max	6.0 9.0	Instant. Minimum Instant. Maximum	Monthly	Grab	OUI-2	

4. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.3 and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-3	Flow calculation for Plant/Equipment Drain Wastewater
OUI-2	At the point of discharge to the OTCW conduits

5. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permitee is authorized to discharge **Water Treatment Plant Wastewater** from I-017 to the OTCW conduits and hence to Outfall D-013. Such discharge shall be limited and monitored by the permitee as specified below and reported in accordance with Permit ConditionI.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	2/month	Pump Logs	FLW-4	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	2/month	Composite	OUI-3	See I.B.7
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	2/month	Grab	OUI-3	
pH	s.u.	Min Max	6.0 9.0	Instant. Minimum Instant. Maximum	2/month	Grab	OUI-3	

6. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.5. and as described below:

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Monitoring Site Number	Description of Monitoring Site
FLW-4	Flow calculation for Water Treatment Plant Wastewater
OUI-3	At the point of discharge to the OTCW conduits and prior to mixing with any other wastewater stream.

7. The composite sample shall be consists of grab samples taken at the beginning, middle and end of the Backwash Basin discharge period.

8. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permitee is authorized to discharge **Heat Recovery Steam Generator Blowdown** from I-018 to the OTCW conduits and hence to Outfall D-013. Such discharge shall be limited and monitored by the permitee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Monthly	Logs	FLW-4	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Monthly	Grab	OUI-4	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Monthly	Grab	OUI-4	

9. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.8. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-5	Flow calculation for Heat Recovery Steam Generator Blowdown
OUI-4	At the point of discharge to the OTCW conduits

C. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in 62-302, F.A.C.; and

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c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

When the analytical results are below method detection or practical quantitation limits, the permitee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

Where necessary, the permitee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permitee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

3. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permitee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permitee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e. monthly, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	Due Date
Monthly	first day of month - last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 - June 30 July 1 - September 30 October 1 - December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 - June 30 July 1 - December 30	July 28 January 28
Annual	January 1 - December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge. The permitee may submit either paper or electronic DMR form(s). If submitting paper DMR form(s), the permitee shall make copies of the attached DMR form(s). If submitting electronic DMR form(s), the permitee shall use a Department-approved electronic DMR system.

The electronic submission of DMR forms shall be accepted only if approved in writing by the Department. For purposes of determining compliance with this permit, data submitted in electronic format is legally equivalent to data submitted on signed and certified paper DMR forms.

The permitee shall submit the completed DMR form(s) to the Department by the twenty-eighth (28th) of the month following the month of operation at the addresses specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

And

Florida Department of Environmental Protection
Southeast District Office
400 N. Congress Ave.
West Palm Beach, Florida 33416
Phone Number - (561) 681-6600

[62-620.610(18)]

4. The permitee shall not submit DMR forms that alter the original format or content of the attached DMR forms without written approval from the Department's Southeast District Office at the address specified below:

   Florida Department of Environmental Protection
   Southeast District Office
   400 N. Congress Ave.
   West Palm Beach, Florida 33416
   Fax Number - (561) 681-6760

5. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications shall be submitted to or reported to, as appropriate, the Department's Southeast District Office at the address specified above. All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. *[62-620.305]*

6. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

7. The Permitee shall develop a Plan of Study (POS), subject to Department review and approval, to monitor compliance with Rule 62-302.520(1), F.A.C. pursuant to the schedule in Item VI.2, including a proposed implementation schedule, designed to determine any effects on biological communities from the discharge to the Lake Worth Lagoon. The plan may include biological sampling prior to start-up of the RBEC Unit 5 in order to establish baseline biological conditions within the receiving waters. The plan shall address monitoring of aquatic species as necessary, including frequency of sampling. The POS shall incorporate relevant existing data developed by the Permitee and other sources as well as any necessary additional monitoring to be conducted by the Permitee.

8. The permitee shall develop a plan in accordance with the schedule in Condition VI.3 to return live fish, shellfish, and other aquatic organisms collected or trapped on the plant intake screens to their natural habitat. Other material shall be removed from the intake screens and disposed of in accordance with all existing Federal, State and /or local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters.

9. The permitee shall maintain plant intake traveling screen practices so as to assure that the screens are cycled at least twice during each 24 hours of continuous operation unless precluded by repair or maintenance requirements.

10. The plant intake through-screen velocity shall be maintained at or below levels that existed prior to plant conversion.

11. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. The permittee shall dispose of all known PCB equipment, articles, and wastes either in accordance with: a) Department-issued permits governing soil thermal treatment (Chapter 62-713, F.A.C.) or Department-approved landfills provided the PCB concentrations meet the Florida landfill's permitted limit when concentrations are less than 50 ppm; or b)40 CFR 761 when concentrations are greater than or equal to50 ppm. *[40 CFR Part 423.12(b)(2)]*

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EXPIRATION DATE: August 27, 2015

12. The Permitee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on December 21, 2000, and the amendment approved on May 8, 2003, and as amended thereafter.

13. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit.

    The company shall notify the Department in writing no later than six (6) months prior to instituting use of any biocide or chemical (except chlorine as authorized elsewhere in this permit) used in the cooling systems or any other portion of the treatment system which may be toxic to aquatic life. Such notification shall include:

    a. Name and general composition of biocide or chemical
    b. Frequencies of use
    c. Quantities to be used
    d. Proposed effluent concentrations
    e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)
    f. Product data sheet
    g. Product label
    h. The Department shall review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without a permit revision by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

II. SLUDGE MANAGEMENT REQUIREMENTS

1. The permitee shall be responsible for proper treatment, management, use, and disposal of its sludge. *[62-620.320(6)]*

2. Decay vegetation and materials removed from intake screens and vegetation, sediments and sludge excavated from the settling basins, cooling tower basins and percolation basins must be properly stored onsite until they are disposed in accordance with requirements in chapter 62-701, F.A.C. and other applicable State and Federal requirements.

III. GROUND WATER REQUIREMENTS

There are no ground water monitoring requirements included in this permit.

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

There are no land application discharges at this facility.

V. CONSTRUCTION, OPERATION AND MAINTENANCE REQUIREMENTS

A. General Operation and Maintenance Requirements

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permitee shall maintain the following records and make them available for inspection on the site of the permitted facility.

GOPHER TORTOISE PERMITTING GUIDELINES

Gopherus polyphemus

April 2008
(Revised November 2011)



FLORIDA FISH AND WILDLIFE CONSERVATION COMMISSION
620 South Meridian Street
Tallahassee, Florida 32399-1600

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI **EXHIBIT** 12
PARTY Florida Power & Light Co.
DESCRIPTION R.R. LaBauve (RRL-7), New Gopher Tortoise Guidelines

Insert: Permitting Guidelines Revisions History

September 2008

Authorized Gopher Tortoise Agent requirements were revised (pages 10 - 13).

March 12, 2009

Revisions to the following sections have been made: definition of "gopher tortoise habitat" added to the glossary; Table 1, Mitigation Contributions, clarified, options for payment revised to delay acceptance of letters of credit; Recipient Site Permits; Appendix 3; Appendix 4; 100% surveying (various sections); 10 or Fewer Burrows permits criteria addressed in new Appendix 11; clarification of permit duration criteria; revision to when proof of local government approval is required; Improved Methods for Baseline Vegetation Sampling and Follow-up Monitoring on Recipient Sites in Appendix 7; Revised Indigo Snake handling and relocation guidance consistent with the U.S. Fish & Wildlife Service.

April 14, 2009

Revisions to the following sections have been made: clarification on permitting phased projects in Permit Duration; clarification on when FWC can provide notice to the permittee to do an on-site inspection of a 100% survey prior capture activities, and what the procedure is if more burrows are discovered Burrow Surveys on Development Sites and in Appendix 4; clarification on when the 100-mile north/south relocation would be waived under Holding and Transport; clarification on permit duration for 5-year permits.

Upon approval of the revision to these guidelines, all guidelines will be implemented with the exception of Settlement permits. Guidelines in this document that address the issuance of Settlement permits (Permit for Authorized Relocation Post-Settlement of Law Enforcement Cases) are shaded because proposed revisions are still in draft form and full stakeholder input has not yet been solicited. Until the Settlement permit has been approved, the "after-the-fact" permit process continues to be in effect.

June 2010

Revisions to the following sections have been made: added clarification on impacts that occur within 25 feet of a burrow; added mitigation contributions for Temporary Exclusion permit; replaced "Settlement" permit with "Disturbed Site" permit; revised marking scheme; added "Authorized Agent" permit activity for "trainer;" included the option for the on-site relocation of tortoises whose burrows compromise existing structures; revised financial assurance requirements; added Appendix 13: "Criteria for Gopher Tortoise Recipient Sites to Qualify as Research Sites."

June 2011

Revised the monitoring and reporting requirements for long-term protected recipient sites; added new criteria for the relocation of gopher tortoises from public projects to contiguous public conservation lands; added pre-application opportunity for potential recipient sites; added new definitions in the glossary, updated Florida Rule numbers, and editorial and punctuation revisions on pages 11, 12, 16, 24, 25, 40, 41, 42, and 53.

November 2011

Added Appendix 12: "Guidelines for Restocking Public Conservation Lands;" revised criteria and mitigation associated with the Disturbed Site permit; updated FWC contact information; clarified that the $200 mitigation only applies to a project one time; clarified about listing assistants to authorized agents on after action reports; editorial and punctuation revisions on pages ii, ix, 1, 11, 13, 16, 17, 21, 23 and 40.

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GLOSSARY

abandoned burrow – burrow appears unused and dilapidated. The entrance is partially or completely collapsed, and the burrow is partially or completely filled with leaves or soil. Recent rains, or recent activity by livestock or humans, do not appear to be the primary reason for burrow collapse. There are no trails into the burrow that might indicate that a tortoise recently passed through the leaf litter or that a small tortoise is using a dilapidated, adult burrow.

active burrow – burrow is in good repair, has the classic half-moon shaped entrance, and appears to be in use by a tortoise. These burrows generally have tortoise tracks or plastron scrapes clearly visible on the burrow floor or on the mound. The burrow floor often contains loose soil caused by tortoise activity. The burrow mound is usually clear of vegetation, and it may contain recently excavated soil. For burrow surveys and tortoise density determination, active burrows are combined with inactive burrows to create the *potentially occupied* classification.

asters – plants in the sunflower family.

baseline density – the estimated density (tortoises per acre) of resident gopher tortoises on a recipient site before relocated tortoises are released.

belt transect – a long, thin plot of specific or variable length and width. Burrows are counted within each transect to provide an estimate of the number of burrows, and tortoises, on a given site.

bucket trap – a plastic bucket (generally five gallons or 19 liters, but may be larger or smaller depending on burrow size) that is sunk directly in front of a burrow opening and covered with paper or cloth and soil (for camouflage) to create a pitfall trap for a gopher tortoise. Bucket traps may capture tortoises leaving or entering a burrow.

caliper – a device used to measure straight-line distance between two points of an object or animal. In this case, a caliper with two long metal "jaws" is used to measure the length of the top (carapace) and bottom (plastron) shells of gopher tortoises; this caliper was designed to measure the diameter of trees and can be obtained from forestry supply companies.

canopy cover – layer of vegetation extending above head height, usually composed of tree branches.

carapace – the top (upper) shell of a tortoise.

carrying capacity – the maximum number of individuals of a species that an area can support, given the amount and quality of food, water, and cover.

clinical signs – veterinary term referring to visible signs or symptoms of disease, illness, or lack of well-being in animals. Nasal discharge is a clinical sign that may be observed when tortoises have upper respiratory tract disease (URTD).

commensal – living in a relationship in which one animal derives food, refuge, or other benefits from another animal without hurting or helping it. The gopher frog, eastern indigo snake, Florida pine snake, and Florida mouse are listed commensal species of the gopher tortoise.

compromised burrow – gopher tortoise burrow that compromises the integrity or utility of an existing structure (e.g., under a propane tank), or the safety of the resident gopher tortoise (e.g., burrows in a grass parking lot, dirt driveway, etc.).

conjunctiva – the mucous membrane that covers the exposed portion of the eyeball and the inner surface of the eye.

conservation easement – a voluntary legal agreement between a landowner and a land trust or government agency that limits the type or amount of development on the landowner's property, thus protecting the land's conservation value while retaining private ownership.

contiguous public conservation land relocation- one type of on-site relocation where a public project occurs within ½ mile to public conservation lands and where the native population of tortoises can remain intact. Public projects and public conservation lands are considered contiguous if two or more upland communities occur within a distance of 2,640 feet (1/2 mile), and there is no physical obstacle [e.g., paved road open to the public (i.e., greater than 2 lanes, curb and gutter or other physical barriers, or a speed limit >30mph), railroad bed, impenetrable fence, river, and lake] that prevents tortoise movement to other upland areas within the relocation/restocking site.

correction factor – also known as a burrow occupancy rate; the percentage of gopher tortoise burrows on a particular site that are occupied at a given time (tortoises generally use more than one burrow over time).

densitometer – a forestry device used to determine canopy cover for a given area.

depth to the seasonal high water table (DWT) – a soil suitability criterion referring to a saturated zone in the soil. Values provided in the Natural Resources Conservation Service (NRCS) website database are representative values (neither the highest nor lowest) for a particular soil type. The average value of the depth to the seasonal high water table range that is provided for each soil type in the NRCS database should be used when determining whether a soil type meets the acceptable or desirable soils criteria.

disturbed site (area)- a site where disturbance to the ground or vegetation has occurred.

donor site – the property, usually a development, from which tortoises are removed during relocations.

enclosure – a temporary, specified area of a recipient site that is surrounded by approved fencing or hay/pine straw bales to initially contain relocated tortoises and to help them acclimate to their new surroundings. See "soft release."

endemic – exclusively native to a particular geographic area.

final stocking rate – the density of tortoises that can be relocated to a recipient site after considering the baseline density of the resident population. The final stocking rate is calculated by determining the maximum stocking rate (also known as the site evaluation stocking rate) and subtracting the baseline density.

filter fabric fencing – see "silt fencing."

forage – plant material, such as grasses, legumes, and other flowering plants, eaten by grazing animals.

global positioning system (GPS) – a satellite-based navigational system; the receiver provides latitude and longitude data for specific applications (in this case, burrow locations).

gopher tortoise habitat – gopher tortoises use a variety of generally upland habitats including, but not restricted to, sandhill, scrub, xeric hammock, mixed hardwood-pine, pine flatwoods, dry prairies, coastal grasslands and dunes, and disturbed habitats (e.g., old fields, pastures).

ground cover – herbaceous plants and the lowest shrubs occupying an area: a generic term used to describe the mat of plants found on the forest floor.

herbaceous –nonwoody plants, generally green and leafy in appearance and texture.

impact - for the purposes of these Permitting Guidelines, unless otherwise noted as a "positive impact," an impact includes any act or outcome as defined in Rule 68A-27.003 F.A.C., that may adversely affect any gopher tortoise or gopher tortoise burrow.

inactive burrow – burrow is in good repair, but does not show recent tortoise use. The lack of tortoise activity may be due to weather or season. These burrows have the classic half-moon shaped entrance, but the soil on the burrow floor is usually hard-packed, as is the burrow mound. There are no tortoise tracks or recently excavated soil, either on the burrow floor or on the mound. The burrow mound may have vegetation growing on it or be partially covered with fallen leaves. For burrow surveys and tortoise density determination, inactive burrows are combined with active burrows to create the *potentially occupied* classification.

infrastructure – structural elements that provide the framework supporting a development (e.g., roads, bridges, water resources, wastewater management, electric power transmission, and telecommunications).

legumes – plants in the bean family.

live trap – a mesh wire cage trap, either homemade or commercially available (e.g., Havahart) that is set directly in front of a burrow to capture the resident tortoise.

local government approval – a permit, agreement, development order, or other authorization issued or granted in writing by the local city or county government having jurisdiction over the property.

long-term protection (habitat) – either privately or publicly owned lands placed under a perpetual (i.e., endless duration) conservation easement.

mesic (habitat) – having a moderate or well-balanced supply of moisture.

midstory – the middle layer, generally 3-9 feet in height, of trees and shrubs (in a multi-layered forest) shaded by taller trees.

mitigation contribution – compensation, usually either in the form of monetary contributions or protected habitat donations, to offset the ill effects of human-related land change (e.g., development) on gopher tortoise populations.

mycoplasma – an infectious agent (bacterium) that has been associated with upper respiratory tract disease in gopher tortoises.

nares – external openings of the nostrils.

off-site recipient area – an area that does not lie within the same boundaries (as defined in the legal description or as identified by the county parcel identification number) of the development area from which tortoises are to be removed and that may be under either the same or different ownership.

on-site recipient area – an area that is located within the same boundaries (as defined in the legal description or as identified by the county parcel identification number) of the development area from which tortoises are to be removed and that is under the same ownership as the development area or contiguous to public conservation lands.

PIT tags – passive integrated transponder (PIT) tags are small microchips (about the size of a grain of rice) that are injected into a tortoise's hind leg using a hand-held applicator. A hand-held scanner reads the tag's electromagnetic code and displays the tag's number. PIT tags provide an alternative method for permanently and uniquely marking individual tortoises.

plastron – the bottom (lower) shell of a tortoise.

plat – a map of land made by a surveyor showing boundary lines, buildings, and other improvements on the land.

population – a group of individuals of the same species that occur in a defined area at the same time and regularly interact or interbreed.

potential tortoise habitat – those land cover types and soil associations that are known to support the life history requirements of the gopher tortoise. These habitats include, but are not limited to, sandhill, scrub, scrubby flatwoods, pine flatwoods, dry prairie, coastal strand, xeric hammock, mixed pine-hardwoods, and disturbed habitats on suitably drained soils.

potentially occupied burrow – this classification combines the active and inactive categories and, therefore, includes burrows with obvious signs of use and those with minimal or no obvious sign of use. A potentially occupied burrow is in good repair and has the classic half-moon shaped entrance. These burrows may have tortoise tracks or plastron scrapes clearly visible on the burrow floor or on the mound, or may have subtle or no tortoise sign. The lack of observable tortoise signs may be due to weather or season. The burrow floor may contain loose soil caused by tortoise activity, or it may be hard packed. The burrow mound may or may not have vegetation growing on it, and it may be partially covered by fallen leaves.

prescribed fire – a planned fire applied within a particular land area under the right weather conditions to accomplish specific, well-defined management objectives.

public conservation lands – publicly owned lands that are currently managed for conservation and are designated as conservation lands by Chapter 253.034, Florida Statutes, purchased for conservation purposes using funds from bonds or other monies dedicated specifically for conservation lands acquisition (e.g., Florida Forever, Preservation 2000, local bond initiatives, etc.), or afforded protection under federal law.

public project – a project on publicly owned land or land on which the government agency or entity has an easement and in which the public agency or entity is the applicant and subsequent permittee. Examples include public roads, schools, and government facilities.

recipient site – the property where relocated tortoises are released.

recommendation – preferred protocol or technique that permit applicants or permittees should follow, but that is not required (i.e., other viable methods are allowed). In the context of these guidelines, a recommendation is generally indicated by use of the verbs "should" or "may."

relocation – deliberately moving wild gopher tortoises.

requirement – action or protocol that must be followed before FWC will issue a permit. A requirement also includes actions that must be undertaken to avoid violating FWC permit conditions and rules. In the text of these guidelines, a requirement is generally indicated by use of the verbs "must" or "shall," or if an action is prohibited, by use of "do not."

rescue relocation – deliberately moving individuals or groups of tortoises to areas that are typically unprotected and may be relatively small, disturbed, or inadequately managed to support long-term population viability. Rescue relocation is conducted primarily to remove wild gopher tortoises from human-caused harm.

responsible relocation – deliberately moving wild gopher tortoises into protected, managed, suitable habitat where their future survival and population viability are very likely. Restocking to such sites where tortoise populations have been severely depleted is a form of responsible relocation; however, tortoises may also be responsibly relocated to sites with resident tortoises where the carrying capacity has been increased through habitat management to provide sufficient forage for additional tortoises.

restocking – deliberately moving wild gopher tortoises into protected, managed, suitable habitat where resident densities are extremely low and where the tortoises' future survival and long-term population viability are very likely.

restocking site – an area of protected, managed, suitable habitat where gopher tortoise populations have been severely depleted or eliminated.

roller chopping – a forestry method for preparing sites for planting pine trees; also used as a land management tool to reduce the height and density of understory vegetation. A bulldozer pulls a heavy cylindrical drum with cutting blades that chop vegetation.

scute – a bony external plate or scale, as on the shell of a tortoise.

seropositive – positive blood test indicating an immune response (exposure) to the bacteria that cause upper respiratory tract disease in gopher tortoises.

shaded – reducing or eliminating sunlight and excessive heat when using bucket traps or live traps or when transporting tortoises. Shade may be provided by man-made materials (e.g., plywood, plastic, cloth) or by vegetation (noting that vegetation dries with time and may fail to provide proper shade for more than a few days).

short-term protection (habitat) – either privately or publicly owned lands that have some enforceable protection commitment, but those commitments do not meet the definition of "long-term protection" or "public conservation lands."

shrub – a woody or herbaceous plant smaller in height than a tree and approximately 3 to 6 feet above the ground, often formed by a number of vertical or semi-upright branches or stems arising close to the ground.

silt fencing (Belton Industries, #935) – a durable type of silt fencing (36 in x 75 ft; pre-assembled, double-stapled, with oak stakes) that has been field-tested as an enclosure material for gopher tortoises. The manufacturer is Belton Industries, PO Box 127, Belton, SC; 800-845-8743; www.beltonindustries.com/silt.html. Distributors include

Pallen Enterprises, Conyers, GA (770-922-1812) and Certified Slings, Ft. Myers, FL (239-334-1343).

silt fencing (filter fabric) – temporary sediment barrier consisting of a filter fabric stretched across and attached to supporting posts and entrenched. There are two types: 1) the silt fence is a temporary linear filter barrier constructed of synthetic filter fabric, posts, and, depending upon the strength of the fabric used, wire fence for support; 2) the filter barrier is constructed of stakes and burlap or synthetic filter fabric. These types of silt fencing are useful for temporary exclusion, but are generally not durable enough for six month-enclosures on recipient sites.

silviculture – the art and science of establishing and growing healthy, high-quality forests to meet human needs.

site evaluation stocking rate (maximum stocking rate) – the maximum allowable density on a particular recipient site, determined by evaluating habitat conditions such as canopy cover, soils, etc. Generally, maximum stocking rates range from two to four tortoises per acre.

site fidelity – remaining within a particular area.

soft release (relocation) – those releases where relocated animals are contained in a temporary enclosure at the recipient site for some period of time before being allowed to roam freely; this differs from hard releases where animals are turned loose without any period to acclimate to their new surroundings.

Strategic Habitat Conservation Area – an area not within existing publicly owned conservation lands that FWC has identified as needing protection to meet minimum conservation goals and provide greater security for rare native plants, animals, and habitats.

take – taking, attempting to take, pursuing, hunting, molesting, capturing, or killing any wildlife or freshwater fish, or their nests or eggs, by any means, whether or not such actions result in obtaining possession of such wildlife or freshwater fish or their nests or eggs.

understory – the lowest vegetative layer in a forest, consisting of woody and herbaceous growth less than 3 feet in height.

unprotected site (relocation) – lands that do not have any enforceable protection commitments or use restrictions that would prevent them from being modified and made unsuitable for tortoises.

upland (habitat) – high, generally dry lands that are not wetlands (water).

upper respiratory tract disease (URTD) – a disease that occurs in gopher tortoises, where infected individuals may show a discharge from the nasal passages or eyes, swelling of

the eyelids or area around the eyes, or reddened third eyelid. These so-called clinical signs (i.e., symptoms) come and go over time.

viable population – a stable, self-sustaining population with a high likelihood (e.g., more than 95%) of surviving for a long-term period (e.g., 100 years).

xeric (habitat) – very dry, in this case due to soil factors.

I. INTRODUCTION

The following gopher tortoise (*Gopherus polyphemus*) permitting guidelines have been produced by the Florida Fish and Wildlife Conservation Commission (FWC), with input from stakeholders, to provide a comprehensive overview of FWC's gopher tortoise permitting system. The new gopher tortoise permitting system has been developed as one tool in accomplishing the goals and objectives set forth in FWC's *Gopher Tortoise Management Plan*, approved in September 2007.

The overall goal of the management plan is to restore and maintain secure, viable populations of gopher tortoises throughout the species' current range in Florida. Objectives under this goal include the following: 1) improving gopher tortoise carrying capacity on lands with existing or potential gopher tortoise habitat; 2) increasing the amount of protected gopher tortoise habitat; 3) restocking gopher tortoises to protected and managed areas; and 4) decreasing gopher tortoise mortality on lands proposed for development.

This permit system has been designed to help accomplish all four of these objectives by providing incentives to landowners to manage their habitat for gopher tortoises, tortoise commensals, and other native wildlife species; providing incentives to responsibly relocate and restock tortoises to protected, managed lands rather than unprotected sites; providing a new permitting system that does not allow entombment of tortoises; and providing a permitting system with regulation and enforcement sufficient to ensure compliance with FWC guidelines and rules.

The *Gopher Tortoise Permitting Guidelines* is a document that may be edited and updated as needed in the future. Proposed changes to these guidelines will be reviewed annually by an FWC standing team and a public stakeholder advisory group. All changes will require approval from the FWC Executive Director. The FWC Executive Director will also coordinate with the FWC Chairman to determine when changes to these guidelines are substantive and warrant full review by the FWC Commissioners.

These guidelines do not address technical details or aspects of the permit application process associated with the gopher tortoise permitting website. The online permitting system allows individuals to register and submit permit applications, electronically submit required mitigation, and receive official communications including permits from FWC. It also allows the public to search for and view permit applications and issued permits. Additional information, instructions and frequently asked questions on the online permitting system is available at MyFWC.com/GopherTortoise.

These guidelines include specific requirements and recommendations for various elements of the gopher tortoise permitting system. *Requirements* include actions or protocols that must be followed before FWC will issue a permit. They also include actions that must be undertaken to avoid violating FWC permit conditions and rules. The terms "shall" or "must" in this document denote guideline requirements. *Recommendations* include preferred protocols or techniques that applicants or permittees should follow, but that are not required (i.e., other viable methods are allowed). The terms "should" and "may" in this document denote guideline recommendations.

These guidelines are intended to be a single source for all policy and protocols associated with FWC's gopher tortoise permitting system. As such, they are written primarily for an audience seeking such in-depth knowledge. Other publications and online materials have been developed to address the informational needs of groups that do not require an in-depth understanding of the entire system.

II. DETERMINING IF A PERMIT IS REQUIRED

Rules and Policies Protecting Tortoises and Their Burrows

Rules protecting gopher tortoises and their burrows, and the Gopher Tortoise Enforcement Policy, are found in Appendix 1.

Activities That Do Not Require a Permit

Agricultural, silvicultural, and wildlife management activities that impact gopher tortoises or gopher tortoise burrows do not require a permit if they are conducted in accordance with the Gopher Tortoise Enforcement Policy (Appendix 1), which is a part of these guidelines. These activities include tilling, planting, harvesting, prescribed burning, mowing, disking, roller chopping, and tree cutting. For additional guidance on activities that do not require a permit, refer to the *Gopher Tortoise Enforcement Policy* in Appendix 1.

Linear utility and highway right-of-way vegetation maintenance activities that may impact gopher tortoises or gopher tortoise burrows do not require a permit. These activities include mowing and tree cutting.

Routine yard and vegetation maintenance and landscaping activities that do not harm gopher tortoises or collapse tortoise burrows do not require a permit.

Note: Agricultural, silvicultural, wildlife management, and linear utility and highway right-of-way vegetation maintenance activities have not been shown to routinely result in significant gopher tortoise deaths (i.e., beyond the infrequent, accidental death of individual tortoises). Therefore, FWC will investigate reports of the death of significant numbers of tortoises to determine if these deaths resulted from activities that did not constitute bona fide agricultural, silvicultural, wildlife management, or linear utility and highway right-of-way vegetation maintenance activities. The FWC may pursue such activities as a violation of Rule 68A-27.003, Florida Administrative Code (F.A.C.), which is included in Appendix 1.

Note: Activities that are intended to prepare land for development are not considered bona fide agricultural, silvicultural, and wildlife management, linear utility, or highway right-of-way vegetation maintenance activities. A permit is required for land development activities (including site preparation for such activities) that result in impacts to gopher tortoises or their burrows. See Site Preparation Activities for Development below.

A FWC permit is not required if development activity on a project site avoids impacts to tortoise burrows by 25 feet in all directions from the mouth of all burrows. Development activity must not harm gopher tortoises nor violate rules protecting them. Leaving a 50-foot diameter (25-foot radius) circle of habitat around each burrow (e.g., undisturbed "islands" or "crop circles") and developing the rest of a project site does not qualify and requires a permit to ensure that gopher tortoises are not harmed. Examples of other violations noted in the past by FWC include but are not limited to killing or injuring a tortoise, harassing a tortoise by blocking access to its burrow, and altering gopher tortoise habitat to such an extent that resident tortoises are taken (see Glossary and Site Preparation Activities for Development, below).

Activities That Require a Permit

A permit is required for any activity not covered in the section above, that causes a take, harassment, molestation, damage, or destruction to gopher tortoises or their burrows (see Rule 68A-27.003, F.A.C., in Appendix 1.) Activities that can lead to rule violations include, but are not limited to, clearing, grading, paving, bulldozing, digging, building construction, and site preparation for development.

Examples of actions that are rule violations include the following:

1) killing or causing direct harm to gopher tortoises
2) collapsing gopher tortoise burrow entrances or other parts of tortoise burrows without a permit
3) blocking, covering, or filling in gopher tortoise burrow entrances without a permit
4) placing harmful substances or devices inside gopher tortoise burrows
5) penning or restricting gopher tortoises into small areas for more than 72 hours without a permit
6) altering gopher tortoise habitat to such an extent that resident tortoises are taken (see Glossary) by such activities
7) excluding tortoises from their burrows without a permit
8) relocating or possessing tortoises without a permit

Site Preparation Activities for Development

A permit is required for any site preparation activity conducted as a precursor to development that disturbs vegetation or the ground which impacts gopher tortoises or their burrows at the time of or as a result of development. To conduct these activities without a permit is a violation of Rule 68A-27.003, F.A.C. (see examples 1-8, above).

Site preparation activities such as hand trimming vegetation and other minor determinations of suitability of property for development do not require a permit. These low-impact activities are allowed without a permit if they do not harm gopher tortoise burrows, harm gopher tortoises, or disturb the ground or vegetation so that accurate tortoise burrow surveys or FWC site checks cannot be conducted. FWC law enforcement will respond to reports of take, harassment,

molestation, damage, or destruction of gopher tortoises or their burrows and investigate any potential criminal violations.

On sites where tortoises are present and burrows (active or inactive) are present, most site preparation activities require a permit. These activities include building construction, bulldozing, paving, clearing, or grading. If work has started without the proper permit, work shall stop on-site until a relocation permit has been obtained and all gopher tortoises have been relocated. If work has begun before a relocation permit is issued or before gopher tortoise relocation is complete, all prior permits may be voided and a Disturbed Site permit may be required.

Permit applications must include tortoise surveys of the entire development, not just infrastructure components. Permits will not be issued solely for proposed infrastructure (e.g., roads and utilities) that are part of a larger common development plan, project, plat, or subdivision. Issued permits must address all burrows to be impacted on the entire project, development, plat, or subdivision site plan (the development footprint). For example, if the entire development footprint impacts more than 10 burrows, such sites will not be eligible (i.e., meet the criteria) for issuance of a 10 or Fewer Burrows permit, even if the infrastructure itself impacts 10 or fewer burrows.

Applicants submitting permit applications for projects with site plans that include lots or space for residential, industrial, institutional, commercial, or other development must consider all burrows within such areas to be impacted by the development footprint. Only those tortoises residing in burrows that are located within either designated preserves or other areas that will not be impacted by any activity associated with the ultimate build-out of the proposed development site do not have to be relocated. Large projects that are subdivided into development phases where each phase is approved by the local government under a separate development order may be permitted separately, but only one 10 or Fewer Burrows permit will be issued per multi-phased project.

If site preparation activities occur before a gopher tortoise relocation permit is issued, then a Disturbed Site permit may be required. The Disturbed Site permit process may result in the denial of an existing permit application or revocation of an issued gopher tortoise relocation permit (see Section IV).

In disturbed site cases, an FWC law enforcement investigation will be conducted to determine if gopher tortoises or gopher tortoise burrows have been impacted. Regardless of the outcome of investigations, the permit application review process will not resume until any gopher tortoises potentially buried in disturbed portions of the project site are given adequate time to dig out (a minimum of 28 days, comparable to that required during tortoise trapping efforts; however, longer periods may be warranted during cold weather when tortoise movement is typically slower).

III. PERMITTING GUIDELINES

The FWC uses a multi-tiered approach to permitting actions involving gopher tortoises. These permits are divided into three main types: 1) Authorized Agent permits, which authorize persons to trap, transport, and release tortoises; 2) Site-specific relocation permits, which authorize trapping and relocation of tortoises either within the boundaries of the area being impacted (on-site) or from the area being impacted to a permitted recipient site (off-site); and 3) Recipient Site permits, which authorize the use of designated sites meeting specific criteria as recipient areas for tortoises. Emergency Take permits, Disturbed Site permits, and Burrow or Structure Protection permits are three additional permit types, only issued under unusual circumstances. The types of permits are illustrated by the flow chart in Appendix 2, FWC Gopher Tortoise Permitting System Process Map.

Entombment of tortoises is not allowed under the conditions of any permit, with the exception of Emergency Take permits. Emergency Take permits are available only in extreme circumstances where there is an immediate danger to public health and safety or in direct response to an official declaration of emergency by the Governor or local government authority. Local emergency situations that do not rise to the level of an official declaration should be handled by coordinating with FWC's Division of Law Enforcement and seeking assistance in determining steps that must be taken in order to avoid additional take or endangerment of gopher tortoises.

Mitigation Contributions

A mitigation contribution is required for all relocation permits. A flat mitigation contribution from each applicant applies to the first 10 burrows (up to 5 tortoises for conservation permits) impacted on each project site. This flat mitigation contribution of $200 is only applied one time for each project site. Additional mitigation for sites supporting more than 10 tortoise burrows is required. Mitigation contributions are assessed by determining the estimated number of tortoises impacted (the number of potentially occupied tortoise burrows to be impacted, divided by 2). A variable scale for additional contributions is based on the overall conservation value of the action being permitted and the estimated number of gopher tortoises being impacted by the project. Preferred conservation actions, such as responsibly relocating tortoises to long-term protected lands, require a lower contribution per tortoise than relocations to short-term protected or unprotected lands or relocations associated with Disturbed Site permits. All mitigation contributions support gopher tortoise conservation actions as specified in the FWC-approved Gopher Tortoise Management Plan.

Other costs may be incurred by applicants obtaining permits or conducting activities related to gopher tortoises. Examples of such costs include fees paid to consultants, fees paid for on-site preparation for gopher tortoise related activities, fees paid to owners of recipient areas, and fees associated with establishing conservation easements. These fees are not paid to FWC nor controlled by FWC.

All mitigation contributions must be submitted to FWC as specified in these guidelines. Gopher tortoise mitigation contributions for a 10 or Fewer Burrows permit, Authorized Agent permit, Recipient Site permit, Temporary Exclusion permit, Burrow or Structure Protection permit, or

Disturbed Site permit must be submitted to FWC before the final permit will be issued. Mitigation contributions for Conservation permits representing 100% of the estimated total amount due will be submitted prior to issuance of the permit. Online submission of mitigation contributions is provided in order to expedite permit processing and issuance. FWC will continue to explore alternative methods of payment, such as letters of credit and performance bonds, in the future.

If the actual number of gopher tortoises relocated is less than the number estimated, a refund of any excess funds paid will be made to the permittee. Permittees seeking a refund must submit a refund request form to FWC within 60 days of the date that the final after action report is approved. Disturbed Site permits follow a different refund process (see Section IV). If an issued gopher tortoise relocation permit is used to attempt to capture a gopher tortoise(s) but no gopher tortoise is captured, the minimum mitigation amount required to obtain that type of relocation permit (e.g., $200 for 10 or Fewer Burrows permits or Conservation permits, or $100 for Temporary Exclusion permits with tortoises excluded for two months or less) will not be refunded to the permittee because the issued permit authorized both the capture of gopher tortoises, and the damage, collapse or covering of gopher tortoise burrow(s).

If the number of tortoises encountered during relocation exceeds the number permitted, then the permittee or agent must stop all attempts to capture any gopher tortoise in excess of the permitted number, and call the FWC Gopher Tortoise Permit Coordinator as soon as possible. The permittee or agent must submit an application to amend the relocation permit, submit the associated mitigation contribution for additional tortoises, and be in possession of the issued amended permit before attempting to capture or relocate any gopher tortoise in excess of the original number permitted.

Juvenile tortoises that are less than 130 mm [5 inches] carapace length must be included on the burrow surveys and permitted for relocation. However, refunds will be provided by the FWC for relocated juvenile tortoises that are less than 130 mm carapace length after the final after action report is submitted and approved, and a refund request form is submitted by the permittee or his/her agent. Gopher tortoise eggs and nests are not included when calculating the mitigation contribution. All eggs and juvenile tortoises must be relocated.

Emergency Take permit mitigation contributions will be handled on a case-by-case basis, in accordance with the facts and circumstances of each permit incident. In cases where the number of burrows impacted can be accurately determined because of pre-existing on-site surveys, mitigation contributions will be calculated by multiplying this number by 0.5. This adjusted number will be used to calculate mitigation contributions as prescribed in Table 1. In cases where the total number of burrows impacted cannot be accurately estimated from prior surveys, mitigation contributions will be based on actual documented burrow evidence. Such evidence may include, but is not limited to, exit holes from old burrows, partial remains of burrows, and the density of gopher tortoise burrows (per acre) that occur within surrounding areas that contain similar vegetation and soil characteristics.

When an Emergency Take permit includes requirements for trapping or excavating burrows within an area that has been disturbed by clearing, grading, disking or other ground disturbance

activities, no refunds will be made if the actual number of tortoises relocated is less than the number estimated, since gopher tortoises may have left the area during the disturbance.

The FWC realizes that all sites are unique and that circumstances influencing gopher tortoise populations are dynamic. For that reason, the initial permitting mitigation contribution is based on estimates from site surveys and a general application of a statewide correction factor. Estimating the total amount due is accomplished by calculating the number of potentially occupied burrows (based on surveys of not less than 15% of the project site areas where potential gopher tortoise habitat is found), dividing by 2, and then applying the mitigation contribution amounts shown for the various permit types described in Table 1.

The mitigation contribution amounts will be adjusted over time to keep pace with inflation. Tying these changes to the Consumer Price Index will ensure mitigation contributions are adjusted relative to actual price increases or decreases. The FWC will use the "All Urban Consumers Price Index" (CPI-U), which is a reflection of the highest percentage of the population, and the CPI-U for the Southeast region. Information on the Consumer Price Index is available online at www.bls.gov/cpi.

In subsequent years, mitigation contributions will change by an amount equal to the annual CPI-U for the Southeast region, and will be based on changes during the CPU calendar year (January 1– December 31). However, the minimum threshold for mitigation is set at the contribution levels outlined in the original approved version of the Gopher Tortoise Permitting Guidelines (April 2008). Adjustments to the contribution amount will take effect on March 1 of each year because the CPI for the previous year is usually not available until mid-February. The contribution will be calculated based on the date that a completed application is received by FWC. Mitigation contribution amounts will be published at MyFWC.com/GopherTortoise and sent out to all permittees.

Table 1. Permit Type and Corresponding Mitigation Contribution

PERMIT TYPE	MITIGATION CONTRIBUTION
Authorized Agent	$500 (one-time contribution)
Recipient Site	$500 per site (one-time contribution)
10 or Fewer Burrows *Tortoises are relocated on-site or off-site**	$200
Conservation *>10 burrows relocated to **long-term protected area, to public conservation lands, or from public projects to contiguous public conservation land***	$200 for first group of 10 burrows (up to five gopher tortoises) $300 each additional tortoise
Conservation *>10 burrows relocated to **short-term protected area***	$200 for first group of 10 burrows (up to five gopher tortoises) $3,000 each additional tortoise
Conservation *Tortoises relocated to **unprotected area***	$3,000 per tortoise
Temporary Exclusion *Exclusions for longer than 6 months must apply for a Conservation permit*	$100 per tortoise (exclusions <2 months) $200 per tortoise (exclusions 2 to 4 months) $300 per tortoise (exclusions 4 to 6 months)
Burrow or Structure Protection *On-site relocation only*	$25 for up to 2 burrows
Emergency Take	$4,000 per tortoise
Disturbed Site *See Section IV. Disturbed Site Permits for more information*	$500 additional per tortoise added to the standard mitigation for 10 or Fewer Burrows permits and Temporary Exclusion permits (exclusions 4-6 months only) $1,500 additional per tortoise added to the standard mitigation for a Conservation permit

*Gopher tortoises relocated off-site under a 10 or Fewer Burrows permit cannot be relocated to an unprotected recipient site.

Documentation for Permit Applications and Issuance

In accordance with the requirements of Rules 68A-27.007 and 68A-27.003 (F.A.C.), a permit for a gopher tortoise capture/relocation/release activity must be secured from FWC before initiating any relocation work. Required information for applications is outlined in Appendix 3, Informational Needs for Relocation Permit Applications and Recipient Site Permit Applications. Checklists are provided at MyFWC.com/GopherTortoise to assist applicants with the required information for each permit type.

As of April 2009, most permits can be applied for online at MyFWC.com/GopherTortoise. The online permitting system allows individuals to register, submit permit applications, electronically submit required mitigation, and receive official communications including permits from FWC. Paper applications are also available, but applicants are encouraged to apply online to expedite the review process. Additional information, instructions and frequently asked questions regarding the online permitting system are available online at MyFWC.com/GopherTortoise.

Paper applications are available online at MyFWC.com/GopherTortoise or from the Gopher Tortoise Permit Coordinator, Florida Fish and Wildlife Conservation Commission, 620 South Meridian Street, Mail Station 2A, Tallahassee, FL 32399-1600; (850)921-1031; (850)488-5297 fax. For those opting to submit paper applications, the complete application should be submitted to the Gopher Tortoise Permit Coordinator at the above address at least 90 days prior to the time needed, although most applications will be processed in 45 days or less. Timely issuance of permits is dependent on receipt of required documentation.

Demonstration of need for a permit will require submittal of a development plan or proof of local government approval for the activity proposed (in the form of preliminary or final subdivision plat, or master planned unit development approval; Development of Regional Impact [DRI] development order; or authorization to commence clearing, grading, or construction activities). The actual capture and relocation authorized by the permit shall be conditioned upon the permittee submitting proof of local government approvals for clearing, grading or construction activities (if required at the local government level) to the FWC prior to commencing capture and relocation activities. Local governments may have requirements that an applicant demonstrate that FWC permits have been issued, or even that FWC permit requirements have been met, before issuing their final local government approval. The FWC will provide letters of intent or special conditions to permits, if necessary, that can be used to demonstrate agency concurrence with a proposed project. However, permits are not issued to move tortoises off a property where no construction activity is planned.

Permit Duration, Permit Posting, and Post-Relocation Reporting

The duration of each type of permit will be indicated on the permit. Authorized Agent permits are valid for a two-year period and may be renewed without additional payment in two-year increments. Recipient Site permits with long-term protection do not expire, but will be subject to reporting requirements within the special conditions. Permits for short-term protected recipient sites and unprotected recipient sites may be renewed every two years, but will require no additional mitigation contribution. Relocation permits for 10 or Fewer Burrows and Burrow or Structure Protection Permits will be valid for six months from the date of issuance and may be amended by the permittee to extend the permit duration for up to 6 months if relocation activities have not been completed. Conservation and Temporary Exclusion permits will be valid for either 12 months or 60 months and may be amended by the permittee to extend the permit duration for up to 12 months if relocation activities have not been completed. Emergency Take permits and Disturbed Site permits will be handled on a case-by-case basis, considering the circumstances of the development and the conditions present. Any request for permit renewal or amendments shall be submitted at least 45 days prior to the expiration date of the existing permit.

Permit amendments are issued based on the permitting guidelines and specific permit conditions in effect at the time the complete application for a permit amendment is received by the FWC.

Phased projects, those projects with development phases based on geographic areas, may be permitted in one permit or in phases. Permits issued for individual phases will have conditions that specify the gopher tortoise conservation activities that must be conducted for those specifically permitted stages or phases of development. Refer to Appendix 3 for information needed for permit applications.

Either the original permit or a complete copy must be clearly posted at the affected site at all times while engaged in the permitted gopher tortoise relocation activities.

Within 30 days of release of the relocated tortoises, the permittee, or authorized agent if applicable, shall submit a report detailing the capture/relocation actions to FWC's Gopher Tortoise Permit Coordinator via FWC's permitting portal at MyFWC.com/GopherTortoise.

Burrow Surveys on the Development Site

A burrow survey covering a minimum of 15% of the potential gopher tortoise habitat to be impacted by development activities (including staging areas for heavy equipment) is required in order to apply for a relocation permit. These 15% surveys must be conducted no more than 90 days before an application is submitted to FWC. Burrow survey methods are outlined in Appendix 4, Methods for Burrow Surveys on Development (Donor) and Recipient Sites. Additional survey requirements for Disturbed Site permit applications are also listed in Appendix 4.

No more than 90 days prior to, and *no fewer* than 72 hours before (excluding weekends and holidays) commencing gopher tortoise capture and relocation activities, the authorized agent shall: 1) complete the 100% gopher tortoise survey of the donor site and burrow location map; and 2) deliver to the FWC the 100% survey and burrow location map. If FWC determines that an on-site survey inspection is necessary prior to commencing capture activities, FWC will provide notification to the permittee or authorized agent within 48 hours (excluding weekends and holidays) of receipt of the 100% survey and burrow location map.

All surveys completed by authorized agents are subject to field verification by FWC. If FWC determines from the on-site survey inspection that the number of gopher tortoise burrows on site causes the total to exceed the number authorized for capture and relocation under the existing gopher tortoise permit, the permittee must apply for an amendment and obtain a permit for the additional burrows from FWC before initiating any capture and relocation activities for the additional burrows.

Site preparation for development (such as land clearing) may commence on the project site, or for phases of the project site, for which gopher tortoise capture and relocation activities have been completed (see Section II for details.)

Capture, Handling, and Transport of Relocated Tortoises

Capture Methods: Tortoises must not be trapped, captured, or transported off project (donor) sites until local authorization for clearing, grading, or construction has been issued. Tortoises may be captured via bucket traps, live traps, hand capture outside burrows, and excavation by hand shovel or backhoe. To prevent impalement of tortoises during backhoe excavation, the backhoe bucket must have a flat plate rather than teeth (long prongs). Use of a pulling rod with a blunted tip to prevent injury to a tortoise will be allowed when the authorized gopher tortoise agent is permitted to utilize this method as authorized in the relocation permit. Only agents permitted to use this method of capture are authorized to capture tortoises using a modified pulling rod.

If bucket or live traps are used, the traps must be shaded, they must be checked at least once per day (preferably twice per day—once in the morning and once in the late afternoon), and they must remain in place for at least 28 consecutive days or until the resident tortoise is captured, whichever occurs first. In cases where traps are set during colder months in northern Florida (November – March) and no tortoise is captured after 28 consecutive days, burrows must be excavated to determine if they are occupied. Drainage holes must be drilled into the bottom and lower sides of bucket traps and must be sufficient in size and number to prevent rainwater from accumulating in the bucket. Bucket traps and live traps are not effective in capturing tortoises during cold weather, particularly in northern Florida (north of State Road 50), because tortoises may remain inactive for extended periods of time. Therefore, bucket traps are not recommended from November through March in northern Florida. In cases where traps are set and no tortoise is captured during winter months in northern Florida, burrows must be excavated to determine if they are occupied. If the 28-day trapping period has passed without a capture and property boundary constraints make excavation impossible, FWC should be contacted to discuss alternatives.

Burrow scoping is not an acceptable method of confirming vacancy or determining occupancy rates because not all potentially occupied burrows can be successfully scoped due to curves or obstructions. However, burrow scopes may be used to enhance capture success for tortoises and their commensals. Capturing a tortoise outside a burrow is not sufficient reason to assume the burrow is vacant. Although all burrows on the donor site must be flagged or otherwise marked, only potentially occupied burrows must be trapped or excavated (see Appendix 4).

All relocated tortoises must be individually marked, measured, and weighed (see exceptions in Appendix 11). Techniques for measuring shells and for uniquely marking individual tortoises (i.e., assigning them a permanent identification number) are provided in Appendix 5.

If gopher tortoise eggs are encountered, the following procedure should be followed:

1) place sand from around the eggs into a container;
2) remove soil from around the eggs carefully (eggs are fragile, please handle with care);
3) use a pencil to place a small "x" on top of each egg;
4) make an egg-sized depression with your finger in the sand in the container;

5) place each egg in a depression with "x" facing up;
6) make note of approximate depth of nest in original burrow location, and;
7) at the recipient site, locate an existing burrow apron or other sandy area in an open, sunlit area and excavate to the approximate depth of original nest, place eggs "x" up in the new nest in approximately the same orientation as they were originally located, and mark the new nest with a ring of fencing or flagging.

Any injury or fatality associated with the capture or relocation of gopher tortoises must be reported to the FWC Gopher Tortoise Permit Coordinator within two days.

Cold and hot weather handling: During the colder months, tortoises shall only be relocated when the low temperature at the recipient site is forecasted by the National Weather Service (www.nws.noaa.gov) to be above 50° Fahrenheit for three consecutive days after release (including the day of relocation). This three-day window of milder overnight temperatures is required to allow the relocated tortoises to settle into the recipient site and to reduce the chance of cold-related stress or mortality.

Because most tortoise relocations occur during the warmer months, overheating is a more common concern. During summer months, releases should not be made during the hottest part of the day at sites where shade is limited. Heat stress on gopher tortoises being captured and transported for relocation can be reduced or eliminated by assuring that captured tortoises and those tortoises being transported for release are continually in shaded or climate controlled conditions.

Holding and Transport: Gopher tortoises must be held in shaded conditions and in individual containers that are large enough to allow the tortoise to turn around. To help prevent dehydration, especially during times of drought, tortoises should be soaked for 20-30 minutes in just enough water to cover the container bottom and to allow the tortoise to easily drink. Moist soil may be used to cover the bottom of the bin. It is appropriate to use soil from the burrow depths during backhoe excavation. Hay, straw, or shredded paper are other acceptable materials to place in the bin.

Gopher tortoises must not be held more than 72 hours after capture—and preferably not more than 24 hours. Tortoises should be transported within covered, well-ventilated areas of vehicles (not in open trucks) and should be kept at moderate temperatures (i.e., 70-85° Fahrenheit).

Recipient areas may be situated any distance east or west of the donor site, but no more than 100 miles north or south of the donor site unless no such recipient site is available. Some recipient sites conducting research can accept tortoises from any location in the state and may be exempt from the 100-mile limit.

Relocated gopher tortoises should be released on the recipient site near existing abandoned burrows or excavated starter burrows. Starter burrows should be excavated to approximately two feet in length at an approximate 45° angle to the ground.

Health Considerations (including testing for mycoplasmal upper respiratory tract disease [URTD] and accommodation of symptomatic/seropositive tortoises): Most health variables are poorly known for wild gopher tortoises, and even veterinarians with advanced training in animal health can have difficulty detecting subtle clues that a tortoise is ill. Authorized agents may refer to Appendix 6 for detailed outlines of cursory health evaluations, clinical signs and symptoms, and a simple disinfection protocol to help prevent spread of pathogens. Although detailed health exams are not required, authorized agents should observe each tortoise for obvious clinical signs such as nasal discharge. Hands and equipment should be disinfected between handling tortoises within a donor site, but all equipment, particularly bins and bucket traps, must be disinfected between uses on different donor sites. Blood tests to detect exposure to the pathogen that causes mycoplasmal URTD are no longer mandated. However, in cases where recipient site owners require mycoplasmal URTD testing before relocation, Appendix 6 contains information on collection and handling of samples. Appendix 6 also provides guidance for the accommodation of symptomatic tortoises (i.e., those individuals that show signs of illness, especially respiratory disease) and those that test positive for mycoplasmal URTD or other diseases.

IV. TYPES OF PERMITS

Authorized Gopher Tortoise Agent Permit

Note: Authorized agents included under this type of permit are not authorized agents of FWC, but rather individuals authorized to handle gopher tortoises. These permits are not issued for scientific collection or research on gopher tortoises.

This permit authorizes the permittee, referred to as an authorized agent, to undertake those activities specified by the permit, including surveying, trapping, marking, transporting, relocating tortoises and tortoise commensals (e.g., gopher frog, pine snake, Florida mouse). The specific activities that an authorized agent is granted permission to perform will be listed on the permit. Authorized Agent permits also allow assistants to work under the authorized agent's supervision if these assistants are registered with the FWC. The permit must be carried at all times by the agent and assistants when conducting permit-related activities. Authorized Agent permits will not allow relocation of tortoises except when accompanied by a 10 or Fewer Burrows permit, a Conservation permit, a Temporary Exclusion permit, a Burrow or Structure Protection permit, or a Disturbed Site permit for a specific project.

Authorized agents must be well-qualified to perform the gopher tortoise conservation actions for which they are requesting permission. Agents will likely be the first point of contact for citizens when they are advised that gopher tortoises are protected. Agents must accurately represent FWC policies, guidelines, and rules to their clients and to the general public. As a benefit of receiving this permit, agents will have access to a streamlined online permitting process for certain gopher tortoise permit approvals.

This permit is conditional so that it can be withdrawn, suspended, revoked, or not renewed for just cause, as determined by FWC. In cases where agents or their assistants violate FWC rules, policies, or guidelines concerning gopher tortoises; engage in unethical or illegal behavior;

falsify gopher tortoise permit applications or monitoring reports; or violate conditions of any gopher tortoise permit, the agent permit may be immediately suspended pending an investigation. Substantiated violations will result in appropriate action, up to and including revocation, at FWC's discretion. Any person whose Authorized Agent permit is revoked will be ineligible for any gopher tortoise related permits for some period of time, depending on the severity of the violation.

Requirements for Authorized Gopher Tortoise Agents

Individual people may submit an application to FWC in order to be authorized to perform different activities related to gopher tortoise conservation. Not all agents will have the interest and the required expertise to perform all activities listed below. Each agent permit will clearly state what the agent is allowed to do and will be conditioned accordingly. Agent permits are authorizations to the agents and the assistants under their supervision to conduct the activities specified. The agent permits do not allow capture, possession, or transport of gopher tortoises unless a relocation permit specific to the development project or activity impacting gopher tortoises or their burrows has also been issued. All experience submitted in support of the application for an Authorized Gopher Tortoise Agent permit must have been from actions conducted in compliance with the FWC gopher tortoise permitting guidelines and standards.

Gopher tortoise surveys:
Applicant must have completed either 1) at least 120 hours conducting gopher tortoise surveys over the past year, or 2) a cumulative total of 480 hours conducting gopher tortoise surveys.

Completion of an FWC-approved training course module in gopher tortoise surveying may be substituted for the experience requirements.

Gopher tortoise capture using bucket trapping *or* live trapping *or* hand shovel excavation:
Applicant must have captured, with no gopher tortoise injuries or mortality, either: 1) an average of 10 gopher tortoises per year by a single method over a four-year period, or 2) a cumulative total of 40 gopher tortoises captured by a single method. Applicants are to list experience for each method separately in the agent permit application, as applicable.

Completion of an FWC-approved training course module in gopher tortoise capture methods may be substituted for the experience requirements.

Gopher tortoise capture using a modified pulling rod:
The applicant must have captured, with no gopher tortoise injuries or mortality, an average of 10 gopher tortoises per year over a four-year period by safely using a modified pulling rod. Applicants must include references to the permits under which the claimed experience was earned.

Certification of additional agents beyond those who meet these criteria will be considered only after further evaluation of this technique by FWC in April 2010.

Note: Not all tortoises can be captured by pulling. Therefore, pulling cannot be used as a method for verifying that a burrow is unoccupied. Pulling may be used only in combination with trapping or backhoe/hand excavation to assure that every tortoise is relocated from a designated donor site.

Completion of a training course will not be accepted in lieu of the experience requirements listed.

Transport, marking, and release of gopher tortoises:
The applicant must have completed, with no gopher tortoise injuries or mortality, either: 1) an average of 10 gopher tortoises per year transported, marked, and released over a four-year period, or 2) a cumulative total of 40 gopher tortoises transported, marked, and released. These activities are considered together as one skill in the agent permit application.

Completion of an FWC-approved training course module in gopher tortoise transport, marking, and release methods may be substituted for the experience requirements.

Collection of blood samples:
The applicant must have completed, under the direct supervision of a qualified veterinarian or other appropriately authorized person, the successful collection of 10 blood samples from gopher tortoises.

Completion of a training course will not be accepted in lieu of the experience listed.

Supervision of gopher tortoise burrow excavations using mechanical equipment:
The applicant must demonstrate with no gopher tortoise injuries or mortality, either: 1) on-site experience of supervising at least 50 gopher tortoise burrow excavations, with the successful extraction of at least 20 gopher tortoises (include references to the permits under which those occurred), or 2) on-site experience under the supervision of another Authorized Gopher Tortoise Agent who was directing backhoe operators in the excavation of at least 50 gopher tortoise burrows, with the successful extraction of at least 20 gopher tortoises, with the applicant actively participating in the recovery of gopher tortoises from the excavated burrows (include references to the permits under which those occurred).

Completion of an FWC-approved training course module in this activity, combined with experience directing backhoe excavation of 30 gopher tortoise burrows with successful extraction of at least 12 gopher tortoises, may be substituted for the full experience requirements above. Burrows mechanically excavated during the approved course in which the applicant actively directed excavation efforts without instructor input can count toward the excavation experience requirement; however, excavation must be conducted under the direct on-site supervision of an Authorized Gopher Tortoise Agent permitted in this technique.

It is the agent's responsibility to select operators of mechanical excavating equipment that are appropriately experienced and to direct their activity in a way that minimizes threats to gopher tortoises, commensal species, and persons assisting with the excavation. The authorized agent must be on-site at all times while mechanical excavation is being performed.

Authorization to train:
Authorized gopher tortoise agents may be authorized to train others in the activities and techniques associated with trapping, handling, and relocating tortoises with completion of a FWC-approved training course. Applicants must specify which courses and sections they will be teaching and provide a letter from the approved training entity verifying employment or agreement to train.

Application Criteria

All applications for the Authorized Agent permit must be from an individual, and the appropriate mitigation contribution as established in these guidelines must be paid before issuance of the permit. Applicants for this permit must provide standard contact information, satisfactory proof of knowledge, and specific gopher tortoise related experience in support of each of the activities they are requesting a permit to conduct. Applicants must list permit numbers under which experience was obtained for each skill listed in their application. For surveys, the applicant may list properties (and the associated gopher tortoise habitat acreages) surveyed, purpose of surveys, and documentation of completion and submittal of survey results where experience was acquired but no FWC permit applications were submitted, instead of listing permit numbers (since permits are not always obtained after surveying efforts). Applicants must swear and affirm that they have committed no wildlife violations in Florida, the information submitted in the application and supporting documents is complete and accurate, any false statement may result in criminal penalties, and agree to abide by all applicable state, federal, and local laws.

Professional certification by any industry body or trade group established for this purpose (gopher tortoise agent authorizations) in the future and approved by FWC may also be provided as supplementary documentation of knowledge and experience.

Note: Approval of courses for certification of gopher tortoise agents shall be at the discretion of the FWC Executive Director or his delegate.

Grounds for Suspension, Revocation or Nonrenewal of Agent Permit

Agents are responsible at all times for their own actions and for the actions of any other person assisting them with their permitted activities. The following will be considered by FWC as grounds for suspension, revocation, or nonrenewal of the permit issued to an agent:

- violations of gopher tortoise related rules, guidelines, or permit conditions
- surveys not conducted in adherence with guidelines
- significant numbers of burrows missed on surveys
- falsification of data submitted to FWC
- failure to appropriately supervise and direct persons assisting them

Assistants to Authorized Agents

An authorized agent may be assisted by additional persons. These assistants will be under the

supervision of the authorized agent and must adhere to all rules, guidelines, and permit conditions when conducting activities relating to gopher tortoises. They must carry a letter from the agent designating them as an assistant and a copy of the authorized agent's permit with them at all times while engaged in activities related to the permit. Such assistants must be directly supervised on-site by the authorized agent during blood collection and/or mechanical excavation of burrows, or they themselves must be an authorized gopher tortoise agent permitted to conduct these activities. In order for an assistant to gain credit for experience to meet qualification requirements for an Authorized Agent permit, the assistant must be listed in the relocation permit after action report within the online permit system. Assistants are not authorized to conduct any gopher tortoise related actions without approval of the authorized agent.

Relocation Permits for Properties with 10 or Fewer Burrows

This type of permit is available when 10 or fewer burrows (and the number of tortoises occupying those burrows) will be impacted on a development site. Application requirements, recipient site criteria, and tortoise handling procedures differ somewhat for this permit type (see Appendix 11.). In cases of phased developments, this permit may be obtained only once for any development on a single identified parcel or within a project under a common plan of development, platting, or subdivision/project name, whichever is largest. As part of the 10 or Fewer Burrows permit application process, the permit applicant must complete the required e-Learning (available online at MyFWC.com/GopherTortoise) or the approved equivalent written training, if the applicant is not an authorized gopher tortoise agent.

Most typical activities associated with residential lawn and landscape maintenance do not require a permit, provided they do not collapse gopher tortoise burrows or harm gopher tortoises. Activities that do require a permit are listed in Section II, Determining If a Permit Is Required. Contacting an authorized agent or FWC before implementing any construction or major habitat modifications is advised.

Consultants who are not Authorized Gopher Tortoise Agents may apply on behalf of property owners for 10 or Fewer Burrows permits when all tortoises will be relocated on-site. The consultant must complete a Registered Agent profile within the online permitting system and complete the e-Learning curriculum. Once submitted, this automatically issued status allows a Registered Agent to apply on behalf of the property owner for permits that do not otherwise require the use of an Authorized Gopher Tortoise Agent. Only property owners can be listed as permittees. Relocation activities for Registered Agents are limited to on-site relocation only using bucket trapping, hand shovel excavation, and live trapping to capture the gopher tortoises. The Registered Agent is not a permit, nor does it provide any authorizations not included in a separately issued 10 or Fewer Burrows permit. (Authorized Gopher Tortoise Agents may conduct activities specified by their permit and do not need to apply to become Registered Agents.)

10 or Fewer Burrows Permit with On-Site Relocation

This permit authorizes landowners or other individuals who have completed FWC online e-Learning to capture gopher tortoises (via bucket trapping, hand-shovel excavation, or live

trapping) and to relocate tortoises to an on-site location within the property boundaries of the development specified in the application. [**Note:** Only an authorized agent permitted to supervise burrow excavations may capture or attempt to capture gopher tortoises using a backhoe.] On-site recipient area criteria can be found in Appendix 11. Landowners may obtain the assistance of an authorized gopher tortoise agent for on-site relocations (as described in *Authorized Gopher Tortoise Agent* above).

Release of tortoises must be accomplished in such a way as to preclude tortoises from returning to their burrows. This permit type requires the temporary installation of filter fabric (silt fencing) or other comparable fencing (buried at least eight inches deep) along the outer edge of the construction right-of-way to block tortoise re-entry into the area of disturbance on the project site during construction activities. This temporary exclusion fencing must be removed following completion of construction activities. Penning is allowed only under this permit type, and only under specified circumstances (see Appendix 11).

10 or Fewer Burrows Permit with Off-Site Relocation

This permit authorizes gopher tortoises to be relocated off the development property to a permitted recipient area (a long-term protected site or a short-term protected site). An authorized agent must perform this relocation on behalf of the permittee. Authorized agents must have their own permit from FWC for working with gopher tortoises and may assist the landowner or developer in obtaining all permit approvals for this type of action.

Conservation Permit

Conservation permits for relocation of tortoises on-site or off-site will be issued when more than 10 burrows will be impacted on a development site and for subsequent activity on properties undergoing development of phased projects when a 10 or Fewer Burrows permit has been previously issued.

This permit authorizes gopher tortoises to be relocated either on-site or off-site of the development property. The permittee must have an authorized gopher tortoise agent perform this relocation. Authorized agents must have their own permit from FWC that authorizes them to conduct the activities required to relocate the gopher tortoises, and they may assist the landowner or developer in obtaining all permit approvals for this type of action.

One of the four objectives of the *Gopher Tortoise Management Plan* is to increase the acres of permanently protected gopher tortoise habitat by providing incentives to landowners who protect habitat under perpetual conservation easements. These protected acres of habitat provide a net conservation benefit and assurance for long term protection and management of the species. Restocking lands where populations have been depleted is another important objective which will also help to reach the Plan's goal. Therefore, mitigation contributions for gopher tortoise relocation are scaled based on the length of assurance for protection and management of the species at recipient sites.

The mitigation contribution for Conservation permits is determined by the level and duration of habitat protection and management provided by the recipient site to sustain gopher tortoises. Conservation permits issued for gopher tortoises relocated to a long-term protected recipient site or from public projects to contiguous public conservation lands will require a $200 mitigation contribution for the first group of ten burrows (up to five tortoises) and a $300 mitigation contribution per tortoise thereafter. If the tortoises are being moved to a short-term recipient site, a $200 mitigation contribution will be required for the first group of ten burrows (up to five tortoises), and a $3,000 mitigation contribution will be required per tortoise thereafter. Gopher tortoises that are relocated to an unprotected recipient site will require a $3,000 mitigation contribution per tortoise (see Table 1).

Conservation permits that involve on-site relocation to undeveloped areas that provide suitable tortoise habitat but that are not protected or do not meet the size criteria for a permitted recipient site will require a $3,000 mitigation contribution for each tortoise. Final stocking density is limited to of two per acre (including tortoises already on-site) within the designated recipient area. On-site relocation to an area that provides habitat protection equivalent to the requirements for a short-term protected recipient site will require $200 for the first 5 tortoises and an additional $3000 for each tortoise relocated on site.

On-site relocation may be authorized to areas that meet the criteria for a long-term protected recipient site, or when tortoises are relocated from public projects to contiguous public conservation lands. A separate long-term protected recipient site permit must be obtained before gopher tortoises are relocated to the on-site area (see Recipient Site Permits below). However, if gopher tortoises are relocated from public projects to contiguous public conservation lands, the recipient site must meet the criteria specified below and be authorized as an on-site recipient site unit under the issued Conservation permit. Mitigation contributions for tortoises relocated to these on-site areas under this permit option qualify for the lower mitigation amount included in Table 1.

Relocating gopher tortoises from public projects to contiguous public conservation lands

The FWC recognizes that keeping tortoises within their native population is an important measure in conserving tortoises. This type of on-site relocation permit option encourages contiguous relocation within public lands by reducing mitigation costs and streamlining the process, thereby facilitating enhanced conservation for tortoises. Under this permit option, gopher tortoises can be retained within their native population instead of being moved off-site or to an on-site short-term or unprotected recipient site.

The intent of this permit option to relocate gopher tortoises from public projects to contiguous public conservation lands is to:

1) Encourage relocation of gopher tortoises from public project sites that are contiguous to public conservation lands;
2) Maintain local gopher tortoise populations, and their genetic and breeding integrity;
3) Minimize stress and other negative impacts to individual gopher tortoises;
4) Minimize the potential for disease transmission to new areas; and

5) Align with and complement existing gopher tortoise relocation options.

The key component to achieving this intent is to limit contiguous relocations to public conservation lands that gopher tortoises could reasonably access naturally and on their own.

This relocation option is intended for public projects where the donor site is contiguous to public conservation lands (see definition) and there is no physical obstacle [e.g., paved road open to the public (i.e., greater than 2 lanes, curb and gutter or other physical barriers, or a speed limit >30mph), railroad bed, impenetrable fence, river, and lake] that would prevent tortoise movement to the recipient site or other upland areas within the relocation/restocking site.

Donor and recipient site parcels or lands that are owned by the same public entity but not part of the contiguous landscape, or donor sites located more than one half mile from the temporary enclosure area within the designated recipient site, will not be considered contiguous under this option. However, this permit option can be used if the contiguous habitat or land is owned by more than one entity, provided that a letter of acceptance is submitted from the recipient site landowner. If linear right-of-way project sites do not meet the definition of contiguous, or do meet the definition of contiguous but donor site tortoise burrow(s) are located more than one-half mile from the temporary enclosure within the designated recipient site, a Conservation permit for off-site relocation must be obtained.

Projects must meet the following criteria for relocating gopher tortoises from public projects to contiguous public conservation lands:

A. To receive a FWC Conservation permit for relocation to contiguous public conservations lands, donor sites must meet the following criteria.
    - The donor site must be contiguous to the public conservation land recipient site.
    - If the recipient site is contiguous but owned by a separate public entity, signed permission from the recipient site landowner must be submitted.
    - Mitigation for tortoises relocated under this Conservation permit option is $200 for the first group of 10 burrows (up to 5 tortoises) and $300 for each additional tortoise.
    - The location of the recipient site temporary enclosure must not be located more than one-half mile from the burrow(s) on the donor site.

B. The recipient site must be contiguous to the donor site and meet the following criteria.
    - Recipient sites must be designated as public conservation lands (see definition) or public lands protected by a minimum 50-year conservation easement (with FWC included as a grantee). For lands where title is held by the State of Florida, the land lease shall be amended to include a recipient site management commitment, and be renewed so the lease is valid for at least 50 years.
    - The public conservation lands recipient site must be a minimum of 40 acres and meet the *acceptable* or *desirable* criteria outlined in Table 2 of these guidelines. Smaller sites in highly developed counties, particularly in southern Florida, will be evaluated on a case-by-case basis, and will be allowed if they are instrumental in retaining the local tortoise resource and can be appropriately managed to perpetuate the relocated population.

- A habitat management plan that includes recipient site requirements that has been approved by the FWC (or a management agreement between the managing agency and FWC), and proof of financial assurance in the form of a general appropriation or allocation approved by a public governing body for management, or equal to that of a long-term protected recipient site (see Appendix 3) must be submitted.
- Monitoring reports that conform to the monitoring requirements described in Appendix 7 of the Gopher Tortoise Permitting Guidelines shall be submitted at the intervals specified for either the duration required for a long-term protected recipient site or 50 years, whichever is shorter.
- The location of the recipient site temporary enclosure must not be located more than one-half mile from the tortoise burrow(s) on the donor site.
- A contiguous recipient site may be utilized for more than one Conservation permit that meets the criteria for this permit option, but the number of tortoises relocated to the site shall not exceed the final site evaluation stocking density.
- The recipient site maximum allowable gopher tortoise density (see Appendix 4) shall not exceed 50% of the maximum stocking density.

Exceptions to some of these criteria may be considered by FWC if the proposed contiguous relocation meets most, but possibly not every requirement outlined in the above criteria, and alternative mitigation activities are also implemented. Examples of alternative mitigation activities that may be considered include: temporarily enclosing tortoises (soft release) for 12 months instead of the minimum of 6 months; permanent fencing that prevents tortoises from entering roadways to reduce the risk of mortality; reduced speed limits adjacent to recipient sites and installation of wildlife crossing signs; or, a combination of these examples or other proposed alternatives that are consistent with and support the intent of these guidelines.

Note: Other options for on-site relocation (short-term or unprotected site) are available if a property does not meet the criteria outlined above for this "contiguous public conservation lands" option.

FWC will review this permit option in two years (from the date of approval) to evaluate if it is still needed and is helping to achieve the management plan goals for the gopher tortoise.

Recipient Site Permits

Criteria for Relocation of Gopher Tortoises to Recipient Sites

The overall conservation goal of the *Gopher Tortoise Management Plan* is "to restore and maintain secure, viable populations throughout the species' current range in Florida." Property owners play a significant role in helping Florida achieve this goal by providing the highest level of security for the gopher tortoise and its habitat on permitted recipient sites. Elements that are integral to meeting this objective include appropriate habitat management, population monitoring, legal protection, and long-term financial assurance provided by the landowner. Not all recipient sites afford relocated gopher tortoises with the same level of protection, however

some sites do provide conservation value by restocking tortoises to managed lands where populations have been depleted, furthering research efforts, preventing the loss of tortoises on development sites, helping to retain local or regional tortoise resources and potentially contributing to the habitat preservation objective if such sites receive long-term protection in the future.

The *Gopher Tortoise Management Plan* contains a series of measurable objectives and conservation actions which include restocking gopher tortoises to protected, managed, suitable habitats where they no longer occur or where densities are low. A team of public conservation land managers has developed guidance regarding the restocking of gopher tortoises on public conservation lands (see Appendix 12). This team includes representatives from the Florida Department of Environmental Protection Florida Park Service, Florida Department of Agriculture and Consumer Services Florida Forest Service, the five Water Management Districts, Florida Communities Trust, and Florida Fish and Wildlife Conservation Commission. Likewise, some of the future research goals outlined in the Gopher Tortoise Management Plan may require the use of sites that receive displaced tortoises to carry out research projects and consequently be designation of research recipient sites. The criteria for research recipient sites are outlined in Appendix 13 and are intended to provide further clarity as to how the agency will implement conservation actions specified in the Plan.

To receive a FWC recipient site permit, candidate properties must meet site suitability criteria for size, soil, and habitat. Site suitability criteria vary according to the level of conservation value provided by the recipient site.

Landowners who meet the basic criteria in these guidelines are encouraged to contact the FWC Gopher Tortoise Permit Coordinator to schedule a pre-application site visit. A preliminary site visit allows FWC staff to evaluate the suitability of the habitat on proposed site. Staff may provide information on habitat management assistance or other measures that may be undertaken prior to completing an application for a FWC recipient site permit. The pre-application site visit can help identify and address potential issues in advance, so the permit application can be processed more efficiently.

A. **Conservation Easements or Other Protection:** The conservation value of a permitted project and the required mitigation contribution is determined by the level of protection afforded to the relocated gopher tortoise at the recipient site. Four levels of conservation have been defined:
   - **Long-term Protected Recipient Sites:** These privately or publicly owned recipient sites must be protected by a perpetual easement that conforms to the standard format available from FWC (see Appendix 8). Conservation easements that were previously granted by landowners to other regulatory, governmental, or conservation entities may be acceptable to FWC if their conditions and restrictions provide habitat protection and management requirements for gopher tortoises and their habitats that are comparable to those contained within FWC's standard easement. However, those easements would need to be modified to designate FWC as a co-grantee.
   - **Recipient Sites for Restocking Public Conservation Lands:** These recipient sites consist of publicly owned lands that are currently managed for conservation and are

either designated as conservation lands by Chapter 253.034, Florida Statutes; purchased for conservation purposes using funds from bonds or other monies dedicated specifically for conservation lands acquisition (e.g., Florida Forever, Preservation 2000, local bond initiatives, etc.); or afforded protection under federal law. These publicly owned lands must provide suitable gopher tortoise habitat and must be actively managed under an approved habitat management plan. The land managing agency and FWC must establish either a Memorandum of Understanding (MOU) or an easement that conforms to the standard format available from FWC. Additionally, existing land leases, covenants, and management plans may need to be amended to provide adequate assurance of management. See Appendix 12 for specific details and requirements for restocking public lands.

- **Short-term Protected Recipient Sites:** These recipient sites have some enforceable protection commitment, but those commitments do not meet the definition of "long-term."
- **Unprotected Recipient Sites**: These recipient sites provide relocated gopher tortoises protection for at least two years.

B. **Size**: Perimeter boundaries of recipient sites should ideally be configured in the form of a block, circle, or similar shape. Uplands are considered contiguous if two or more upland communities occur within a distance of 1,000 feet, and there is no physical obstacle (e.g., paved road open to the public, railroad bed, impenetrable fence, river, lake) to prevent tortoise movement to other upland areas within the recipient site. For administrative purposes, FWC will evaluate and authorize use of up to 1,000 acre portions of recipient sites in phases; however, only a one-time mitigation contribution of $500 will be required for permitting a recipient site.

- **Long-term Protected Recipient Sites:** Recipient sites must contain a minimum of 40 acres of contiguous suitable upland tortoise habitat that meet the criteria for soil and vegetation. Smaller sites in highly developed counties, particularly in southern Florida, will be evaluated on a case-by-case basis, and will be allowed if they are instrumental in retaining the local tortoise resource and can be appropriately managed to perpetuate the relocated population. Sites containing greater than 200 acres of contiguous suitable upland habitat will satisfy the size threshold for *Desirable* criteria and may be eligible for an additional 0.5 tortoise per acre increase in the site evaluation maximum allowable tortoise density (see below).
- **Recipient Sites for Restocking Public Conservation Lands:** Recipient sites must contain a minimum of 40 acres of contiguous suitable upland tortoise habitat that meet the criteria for soil and vegetation. Smaller sites in highly developed counties, particularly in southern Florida, will be evaluated on a case-by-case basis, and will be allowed if they are instrumental in retaining the local tortoise resource and can be appropriately managed to perpetuate the relocated population. Sites containing greater than 200 acres of contiguous suitable upland habitat will satisfy the size threshold for *Desirable* criteria and may be eligible for a 0.5 tortoise per acre increase in the site evaluation maximum allowable tortoise density.
- **Short-term Protected Recipient Sites:** Sites must contain a minimum of 25 acres of contiguous suitable upland tortoise habitat that meet the criteria for soil and vegetation.

- **Unprotected Recipient Sites:** Sites must contain a minimum of 25 acres of contiguous suitable upland tortoise habitat that meet the criteria for soil and vegetation.

C. **Soils**: Soils that meet *acceptable* criteria are moderately well-drained to excessively drained, with an average depth to the seasonal high water table (DWT) value of 45 centimeters (1.5 feet) or greater. For sites in flatwoods, land cover maps should be overlain on soils maps to help differentiate hydric areas from more mesic or xeric areas; site visits by FWC may also be required. Poorly drained soils with an average depth to the seasonal high water table (DWT) greater than 31 centimeters (one foot) may meet the *Acceptable* criteria, provided that the proposed site contains augmentation features or is drained by ditches, etc. In these select cases, there must be evidence of past or current use by tortoises. Additionally, stocking densities cannot exceed two per acre on these soil types. Long-term protected recipient sites with an average depth to the seasonal high (DWT) of 130 centimeters (4.3 feet) or greater meet the *Desirable* criteria threshold and may be eligible for a 0.5 tortoise per acre increase in the site evaluation maximum allowable tortoise density. Site-specific soil information can be obtained by referring to the Natural Resources Conservation Service (NRCS) Web Soil Survey (www.soils.usda.gov) for the appropriate county.

D. **Vegetation Features**: Sites with *Acceptable* habitat features are those that contain both of the following: average herbaceous cover of at least 30% and average canopy cover of 60% or less. Woody vegetation should not comprise more than an average of 20% of the herbaceous ground cover. Long-term protected recipient sites and public conservation lands recipient sites for restocking with average herbaceous cover greater than 50% and average canopy cover less than 40% meet the *Desirable* criteria threshold and may be eligible for a 0.5 tortoise per acre increase in the site evaluation maximum allowable tortoise density. Herbaceous cover (low-growing, soft-stemmed plants) should include broadleaf grasses and, preferably, grass-like asters (sunflower family) and legumes (bean family). Vegetation survey methods are outlined in Appendix 7.

E. **Enhanced Conservation Value**: Proposed long-term protected recipient sites and recipient sites for restocking public conservation lands may be awarded a 0.5 tortoise per acre increase in the site evaluation maximum allowable tortoise density if FWC determines that the site has enhanced conservation value by any of the following: 1) adjacency to existing public or private conservation lands that together provide >200 acres of contiguous suitable upland gopher tortoise habitat that satisfy the threshold for *Desirable* criteria; 2) the site boundaries are 100% within a designated Strategic Habitat Conservation Area; or 3) at least 75% of the recipient site is vegetated with one or more of the following native upland plant communities: sandhill, scrubby flatwoods, or dry prairies (Table 2).

F. **Baseline Densities**: Survey techniques to determine the existing (baseline) tortoise population density are provided in Appendix 4. Supporting information should include potential reasons for low tortoise densities (e.g., past harvest; previous, but now rectified, inadequate habitat management). The burrow survey used to generate this estimate must be performed no more than 90 days before the date the permit application is submitted. A map showing the site boundaries, transect locations, locations of all documented tortoise

burrows, and corresponding tortoise densities will serve as the baseline for future monitoring efforts.

G. **Site Evaluation Stocking Rate**: The site evaluation stocking rate is defined as the maximum allowable gopher tortoise density as determined by the scoring process depicted in Table 2, *Acceptable and Desirable Criteria Thresholds for Recipient Site Characteristics*. A site that meets all three *Acceptable* criteria will be assigned an evaluation stocking rate of two tortoises per acre. Evaluation stocking rates for long-term protected recipient sites recipient sites for restocking public conservation lands may increase in increments of 0.5 individual per acre for each *Desirable* criterion that is met, up to a maximum of two additional individuals (four per acre total).

H. **Determination of Final Stocking Rate**: The final stocking rate for a recipient site equals the site evaluation stocking rate minus the baseline density, i.e., final stocking rate = (site evaluation stocking rate) - (baseline density). For all calculations involving stocking rate, consider only tortoises greater than or equal to 130 mm (5 inches) in carapace length. Eggs and juvenile tortoises less than 130 mm are not considered in these calculations because of their low survivorship and minimal effect on the recipient site forage base. Recipient sites for restocking public conservation lands shall be stocked at no more than 50% of the site evaluation stocking rate

When assigning the baseline density and calculating the final stocking rates, applicants submitting permit requests for sites that have been previously approved by FWC and used as a recipient site for tortoise standard relocation and/or incidental take permits shall include the number of resident tortoises reported for the site when it was originally approved and all tortoises released at the site under previously issued FWC permits (or authorized for release when no post-relocation reports have been sent to FWC).

I. **Enclosure Methods**: Restraint of tortoises inside an enclosure at the recipient site for a minimum period of six months is required for all relocations as a condition of the relocation permit. This process is called "soft release." Recent studies have indicated that site fidelity is enhanced by temporarily enclosing tortoises. Because there is still insufficient scientific knowledge regarding tortoise carrying capacity, tortoise response to relocation, post-relocation site fidelity, social interactions between relocated and resident tortoises, and possible disease transmission through relocations, FWC is establishing experimental guidelines at this time to initiate relocation within temporary enclosures and to evaluate the effects. As additional information becomes available, these guidelines may be modified to ensure that they achieve the management plan objectives. The following guidelines include enclosure methods and procedures proven to be effective.

- All tortoises relocated to any recipient site (including unprotected recipient sites) shall be released into a temporary enclosure as described below and retained within the enclosure for a period of not less than six months and no more than twelve months. However, there is no maximum enclosure time limit for recipient sites that are permanently fenced in their entirety and that are stocked at a density equal to the approved final stocking density for the site.
- Applicants with special circumstances may apply to be released from this

requirement. Special circumstances include the following: recipient sites with natural or artificial boundaries to restrain most tortoises (e.g., islands, coastlines, major rivers or large lakes, existing fencing that prevents the passage of all tortoises released at the site).

- Tortoises shall be released into temporary fenced enclosures at no more than 1.5 times the approved overall final stocking density for the site. However, the maximum number of gopher tortoises approved by FWC for release into the entire recipient site parcel shall not be exceeded. Enclosures within recipient sites with varying approved stocking rates may be stocked at 1.5 times the approved density for the area in which the enclosure is located. If an enclosure encompasses an area with varying approved stocking rates, then the enclosure's approved gopher tortoise density will be proportional to the number of acres in each approved stocking rate area. For example, if a 40-acre recipient site initially containing no gopher tortoises includes a 15-acre enclosure encompassing five acres that are approved for a final density of two gopher tortoises per acre and ten acres that are approved for a final density of three gopher tortoises per acre, then the enclosure can receive up to 60 gopher tortoises 1.5 [(5 x 2) + (10 x 3)].
- Temporary enclosures may be of any material that prevents the passage of tortoises of all sizes released to the site. Recommended and cost-effective materials include Belton Industries #935 pre-assembled silt fence (a more durable type of silt fence; see Glossary for purchasing information) and hay or pine straw bales.
- With the exception of hay or pine straw bales, temporary fencing must be buried at least eight inches into the ground to prevent tortoises pushing beneath the enclosure and must be at least two feet high and of sufficient robustness to prevent tortoises pushing or climbing over.
- Temporary fencing must be regularly monitored and maintained to repair damage and maintain the integrity of the temporary enclosure.
- Tortoises observed above ground and tortoise burrow numbers and activity status within the temporary enclosures shall be monitored weekly for the first month and monthly thereafter to document any problems with relocated tortoises (e.g., illness, mortality, evidence of human poaching, emigration). The FWC permitting office must be contacted if decreases in tortoise numbers are documented.

J. **Management Plan:** Gopher tortoise habitat requires active management. A detailed management plan mirroring the length of protection is a vital part of gopher tortoise conservation efforts on all FWC-permitted recipient sites. Management plan requirements are outlined in Appendix 3.

Table 2. *Acceptable* and *Desirable* Criteria Thresholds for Recipient Sites

SITE CHARACTERISTIC	ACCEPTABLE CRITERIA	DESIRABLE CRITERIA
Size	> 40 acres	> 200 acres
Soil	> 45 cm DWT, with land cover verification for flatwoods sites >31 cm (select cases)	>130 cm DWT
Habitat	> 30% herb cover < 60% canopy cover	>50% herb cover <40% canopy cover
Enhanced Conservation Value		Adjacent to protected land, or in Strategic Habitat Conservation Area, or ≥75% native upland community (maximum of 0.5 per acre)
Maximum Allowable Gopher Tortoise Density	Two per acre (requires all above criteria be satisfied)	0.5 per acre for each site characteristic that is satisfied, up to a maximum of two additional (four per acre maximum)

Temporary Exclusion Permit for Major Linear Utility Corridors

This type of on-site relocation conservation permit is specifically reserved for the installation or maintenance of major linear utility transmission lines (e.g., major natural gas or electric transmission lines). This permit applies to situations that require the temporary exclusion of tortoises from the utility construction corridor and where habitats within the corridor will be restored to provide suitable habitat for tortoises following completion of the utility installation. These permits require the temporary installation of filter fabric (silt fencing) or other comparable fencing (buried at least eight inches into the ground) along the outer edge of the construction right-of-way to block tortoise re-entry into the corridor during construction activities. Such fencing is only required along those portions of the construction corridor where tortoises are documented and are to be relocated from the construction area. The FWC will also consider other proposed options of keeping gopher tortoises out of harm's way in the immediate area of construction on these types of projects.

Temporary exclusion permits authorize the capture of tortoises from within the utility corridor right-of-way project area and their immediate release on the other side of the temporary fencing into adjacent suitable habitat. Tortoises must be released outside the project corridor in close proximity relative to where each tortoise was captured. The gopher tortoise density after

relocation within the designated recipient area shall not exceed either three tortoises per acre, or 1.5 times the existing gopher tortoise density within the recipient area, whichever is greater. This does not authorize placement of tortoises on properties not under control of the permittee. The permittee must obtain written approval from the adjacent landowner granting permission to the permittee to release the tortoises on the landowner's property. The temporary fencing must be removed following completion of the utility project and after the habitat has been restored. Tortoises can then naturally reoccupy restored habitat within the utility corridor.

Gopher tortoises may be released into an on-site enclosure in conformance with the FWC enclosure requirements. Enclosures shall not be located on the opposite side of barriers which deter tortoises from returning to the location where they were originally captured. Enclosure fencing shall be removed before expiration of the permitted maximum temporary exclusion time period or upon project completion, whichever comes first. The final gopher tortoise density within the enclosure shall not exceed three gopher tortoises per acre.

The application information requirements for this permit are the same as for conservation permits with on-site relocation of the affected tortoises. This permit is not intended, and will not be issued, for the installation of local utility service lines that are being installed as a precursor to development or to facilitate the development of the adjacent or surrounding area (e.g., infrastructure for specific development projects, planned subdivisions, or multiple projects or subdivisions). Permit applications for those projects must address impacts to all tortoises and tortoise burrows contained within the entire planned project development boundaries. For major linear utility corridor projects that include the construction of permanent structures used to service or maintain the installed utilities (e.g., gas compressor stations, water wells, pumping stations) do not qualify for a Temporary Exclusion permit and must be permitted separately to permanently relocate gopher tortoises.

Burrow or Structure Protection Permit

Burrow or Structure Protection permits are available when the integrity or utility of an existing structure is jeopardized by one or two burrows and therefore poses a public safety concern (e.g., burrow under a propane tank), or if the safety of the resident tortoise is compromised (e.g., burrows in a grass parking lot, dirt driveway, etc.). Application requirements and tortoise capture and handling procedures are similar to those for 10 or Fewer Burrows permits (See Appendix 11); however, tortoises relocated under a Burrow or Structure Protection permit shall only be relocated on-site. This type of permit may only be issued once a year for a contiguous property under the same ownership. As part of the application process, the applicant must complete the required online training (available at MyFWC.com/GopherTortoise) or the approved equivalent written training, unless the relocation activities are conducted by an Authorized Gopher Tortoise Agent.

In most cases, it is best to live with tortoises and their burrows. Relocations are stressful for gopher tortoises. The process takes time, money, and physical labor. Typical activities associated with residential lawn and landscape maintenance do not require a permit, provided the activities do not collapse gopher tortoise burrows or harm gopher tortoises. Activities that

require a permit are listed in Section II, Determining If a Permit Is Required. Visit MyFWC.com/GopherTortoise or contact FWC for more information on living with gopher tortoises.

On-Site Relocation under the Burrow or Structure Protection permit

This permit authorizes landowners or other individuals who have completed FWC online training to capture gopher tortoises (via bucket trapping, hand-shovel excavation, or live trapping) and to relocate tortoises to an on-site location within the property boundaries specified in the application. [**Note:** Only an authorized agent whose permit authorizes the supervision of burrow excavations using mechanical equipment may capture or attempt to capture gopher tortoises using a backhoe.] On-site recipient area criteria follow the same criteria as the 10 or Fewer Burrows permits and can be found in Appendix 11. Landowners may obtain the assistance of an authorized gopher tortoise agent for on-site relocations, as described under *Authorized Gopher Tortoise Agent Permit* above.

Release of tortoises must be accomplished in such a way as to preclude tortoises from returning to their burrows. Penning is not allowed under the Burrow or Structure Protection permit. These permits may require permanent or temporary fencing in an appropriate configuration to exclude tortoises from returning to the compromised burrow. Collapsing or filling those burrows is required upon capture and relocation of the resident tortoises. If fencing is necessary, a brief explanation should be provided in the application addressing why and what methods will be used to restrict tortoise access.

Tortoises cannot be relocated off-site under a Burrow or Structure Protection permit. If adequate suitable gopher tortoise habitat is not available on-site and tortoises must be moved off-site, applicants may qualify for a 10 or Fewer Burrows permit.

Emergency Take without Relocation Permit

This permit will be issued only under limited and specific circumstances, in cases where there is an immediate danger to the public's health and/or safety or in direct response to an official declaration of a state of emergency by the Governor of Florida or a local governmental entity. Applications submitted for this permit must include all information that is required from any other applicant seeking a conservation permit, along with a copy of the official declaration of a state of emergency. This permit process may be handled after the fact or at least after construction activities have already started. It is preferred that contact with FWC should be made as soon as possible to minimize adverse impacts to gopher tortoises and their burrows.

This section does not cover what should happen when a local emergency requiring immediate action to protect human safety and welfare, property, and wildlife and its habitat occurs. Because it is not possible to anticipate every circumstance (*e.g.*, a local oil spill along a highway that contaminates soil adjacent to a gopher tortoise burrow), the best solution would be for anyone encountering an emergency to contact FWC as soon as possible and to request assistance in determining the best course of action to take.

Disturbed Site Permit

Criteria for Relocation of Gopher Tortoises from Disturbed Sites

The Disturbed Site permit may be required in situations where premature disturbance to the vegetation or ground has occurred before gopher tortoise burrow surveys are complete or before gopher tortoise capture and relocation activities have been completed. This permit provides an option for mitigation and relocation of tortoises within disturbed portions of the project area. These permits are not punitive and may or may not be issued in association with FWC law enforcement investigations, but will not be issued until all associated FWC law enforcement investigations have been completed. Survey, capture, and relocation activities must be conducted by an Authorized Gopher Tortoise Agent.

Disturbed Site permits are issued when ***all four criteria*** below are met:

- Evidence of site disturbance to the ground or vegetation must be present on the site and within suitable gopher tortoise habitat
- Site disturbance either prevents:
  - Complete and accurate tortoise burrow surveys from being conducted (15% and 100% surveys as described in FWC guidelines), or;
  - FWC staff from conducting on-site inspections to verify 15% or 100% survey results prior to site disturbance commencing.
- Any one of the following applies:
  - Impact is to any part of the project area with documentation of gopher tortoises burrows on site (e.g., a past, valid, tortoise burrow survey of the disturbed area exists, showing burrows were present; physical evidence that burrows were present; or photographs), or;
  - Evidence of tortoise burrows is visible within the disturbed area, on the property where disturbance occurred, or is within close proximity on adjacent properties, or;
  - Evidence of impact to any tortoise or tortoise burrow.
- Disturbance to the project site has occurred within the past 18 months.

The criteria above may be met before a tortoise permit application has been received by FWC, during the permit application process, or after a permit has been issued, depending on when disturbance activities occur.

If the project site meets all criteria before 100% burrow survey reports and maps are submitted to FWC, or before the 72-hour waiting period after which such reports have been received by FWC, or before the completion of gopher tortoise capture and relocation activities, then active relocation permits or permit applications will be revoked or denied so that a Disturbed Site permit application may be submitted.

In cases where only a portion of the project site is prematurely disturbed and all relocation activities will not be covered under a Disturbed Site permit, another relocation permit (e.g.,

Conservation permit) will be issued for the remainder of the property. This only applies when discrete and contiguous, undisturbed areas of the project site can be identified.

Disturbed sites require different burrow survey protocols for estimating numbers of tortoises present and calculating mitigation contributions. Refer to Appendix 4 for details.

Mitigation Contributions, Refunds, and Recipient Site Requirements

All mitigation contributions must be submitted before Disturbed Site permits are issued. Mitigation contributions for Disturbed Sites are higher than for other relocation permits to mitigate for tortoises which may be buried underground or have left the project site in response to disturbance activities and cannot be relocated. FWC may provide a refund for each tortoise successfully captured and relocated as described for each permit type. Refunds for mitigation are not provided if no tortoises are relocated.

Areas within the project site that were not disturbed will be covered in a separate conservation or temporary exclusion permit. Reduced mitigation for relocation permits for the first five tortoises (10 burrows) will only be allotted for one of the two permits associated with the project. The disturbed site permit and other associated permit will be applied for concurrently.

All project sites qualify for one of three disturbed site permit types: "10 or Fewer Burrows," "Conservation," or "Temporary Exclusion." The entire project site is considered when determining the permit category, including any undisturbed areas (which are permitted separately). For example, a project site with 10 burrows inside disturbed areas and three burrows outside disturbed area (i.e., a total of 13 burrows) would qualify for a Disturbed Site Conservation permit. In this case, a Disturbed Site Conservation permit would authorize gopher tortoise relocation for the disturbed areas and a separate Conservation permit would authorize gopher tortoise relocation for the undisturbed portion of the project site. Temporary Exclusion Disturbed Site permits only cover the disturbed portion of the project site.

Disturbed Site 10 or Fewer Burrows Permit

The mitigation contribution for this permit follows the standard 10 or Fewer Burrows permit (outlined in Table 1.) with an additional $500 required for each tortoise estimated within the disturbed area. FWC may provide a refund of $500 for each tortoise successfully captured and relocated. In instances where additional tortoises greater than the original permitted number are found, a permit amendment must be requested (with additional mitigation) and received prior to continuing relocation activities.

Disturbed Site Conservation Permit

The mitigation contribution for this permit follows that of the standard Conservation permit (outlined in Table 1.) with an additional $1,500 required for each tortoise estimated within the disturbed area. FWC may provide a refund of $1,500 for each tortoise successfully captured and relocated. In instances where additional tortoises are captured greater than the original permitted

number, a permit amendment must be requested (with additional mitigation) and received before additional tortoises are relocated.

Disturbed Site Temporary Exclusion Permit for Major Linear Utility Corridors

The mitigation contribution for this permit follows that of the Temporary Exclusion permit for exclusions of 4-6 months (outlined in Table 1.), with an additional $500 required for each tortoise estimated within the disturbed area. FWC may provide a refund of $500 for each tortoise successfully captured and relocated. In instances where additional tortoises are captured greater than the original permitted number, a permit amendment must be requested (with additional mitigation) and received before additional tortoises are relocated.

Due Process for Gopher Tortoise Permit Applicants

The FWC adheres to the time requirements specified in Chapter 120, Florida Statutes, for processing permit applications. Upon submittal of an application, FWC staff will respond within 30 days requesting any additional information from the applicant. Upon receipt of all information necessary to complete an application, FWC staff will prepare and issue a permit within 90 days (but attempt to accomplish this within 45 days). Any person has a right to challenge the action of FWC on a given permit application. Each permittee is provided an "Election of Rights" form with the issued permit that conveys instructions for filing an informal or a formal hearing request.

Any non-permitted person who believes that their substantial interests would be affected by the action taken by FWC on a gopher tortoise permit application may also petition the agency for a hearing. For information on how to submit such a request, please contact: The Office of General Counsel, Florida Fish and Wildlife Conservation Commission, 620 South Meridian Street, Tallahassee, Florida 32399-1600.

Deviations from permitting requirements shall be granted only when the person subject to the requirements demonstrates a substantial hardship not intended by these guidelines and which violates principles of fairness. The person must also demonstrate the goals of the underlying Gopher Tortoise Management Plan will be or have been achieved by other means. For purposes of considering granting a deviation, "substantial hardship" means a demonstrated economic, technological, legal, or other type of hardship to the person requesting the deviation. For purposes of considering granting a deviation, "principles of fairness" are violated when the literal application of rules or guidelines affects a particular person in a manner significantly different from the way it affects other similarly situated persons.

V. HANDLING OF COMMENSAL SPECIES DURING RELOCATIONS

As the keystone species of Florida's uplands, the gopher tortoise provides refuge to some 350-400 other species. These commensal species may be intimately tied to tortoise burrows or may be occasional visitors, but the underground microhabitats serve as multi-purpose retreats that are

used for feeding, resting, reproduction, and protection from temperature extremes, moisture loss, and predators. Threats to commensal species are similar in nature to those faced by the gopher tortoise and have been addressed in the Gopher Tortoise Management Plan. One of the objectives outlined in the Management Plan is to promote the responsible, humane relocation of burrow commensals encountered during relocation efforts. An added benefit is the likely increase in biodiversity when commensals are released with the tortoises on recipient sites. The guidelines in Appendix 9 have been created to provide guidance for authorized agents who capture commensal species during gopher tortoise relocations. Emphasis is placed on four listed species, with the understanding that these species have habitat needs that generally go beyond those of the gopher tortoise and will, therefore, need to be considered during relocations.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	**EXHIBIT**	13
PARTY	Florida Power & Light Co.		
DESCRIPTION	R.R. LaBauve (RRL-8), Excerpt from St. Lucie Plant (PSL)NPDES Permit		

Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by:

Florida Power & Light
Mr. Richard L. Anderson
Vice President
6451 S. Ocean Drive
Jensen Beach, Florida 34957

PA File No. FL0002208-011-IW1S
St. Lucie Plant Units 1 and 2
NPDES Permit No. FL00002208
St. Lucie County

NOTICE OF PERMIT ISSUANCE

Enclosed is Permit Number FL0002208 to Florida Power & Light authorizing wastewater discharge from Units 1 and 2 at the St. Lucie Plant to the Atlantic Ocean, a Class III marine water, issued under Section 403.0885, Florida Statutes, and DEP Rule 62-620, Florida Administrative Code.

Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any.

Any party to this order (permit) has the right to seek judicial review of the permit under Section 120.68, Florida Statutes, by the filing of a Notice of Appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000 and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within thirty days after this notice is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mark P. Thomasson, P.E.
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Progress Energy Florida
Crystal River Energy Complex Units 4 &5

NPDES Permit No. FL0036366

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed by certified mail before the close of business on 09-29-2011 to the listed persons.

[Clerk Stamp]

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Shirley Shields 09-29-2011
Clerk Date

Copies furnished by certified mail to:
Mark Nuhfer, NPDES Permitting Section, EPA Region 4, Atlanta, GA
Chairman, Board of St. Lucie County Commissioners

Copies furnished by First Class mail to:
Florida Fish and Wildlife Conservation Commission, Conservation Planning Services
U.S. Fish & Wildlife Service
John Jones, Florida Power & Light

Copies furnished by intradepartmental mail to:
Linda Brien, P.G., DEP West Palm Beach
John A. Armstrong, P.E., DEP West Palm Beach
Michael Hambor, DEP West Palm Beach
Terry Davis, DEP St. Lucie
Cindy Mulkey, DEP Tallahassee

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Florida Power & Light (FPL)

RESPONSIBLE OFFICIAL:
Richard L. Anderson
Vice President
6501 S. Ocean Drive
Jensen Beach, Florida 34957

PERMIT NUMBER: FL0002208 (Major)
FILE NUMBER: FL0002208-011-IWIS
ISSUANCE DATE: **September 29, 2011**
EXPIRATION DATE: **September 28, 2016**

FACILITY:

St. Lucie Power Plant Units 1 and 2
Hutchinson Island
St. Lucie County, Florida
Latitude: See Note Below Longitude: See Note Below

Note: Latitude and longitude are not shown at the permittee's request, for purposes of Homeland Security pursuant to federal regulations found at 18 CFR 388.113(c)(i) and (ii) and by Presidential Directive dated December 17, 2003.

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.) and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. This permit is accompanied by an Administrative Order, pursuant to paragraphs 403.088(2)(e) and (f), Florida Statutes. Compliance with Administrative Order, AO022TL is a specific requirement of this permit. The above named permittee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:

The facility is an electric generating plant with a total nameplate rating of 1908 megawatts. The facility consists of two nuclear powered steam electric generating units (Unit 1 and Unit 2).

Units 1 and 2 use water from the Atlantic Ocean, a Class III marine water body, to remove heat from the main condensers via the once-through cooling water (OTCW) and auxiliary equipment cooling water (AECW) systems. Cooling water gravity flows from the Atlantic Ocean through three offshore intake structures into the intake canal. The water is then pumped through the main condensers for each unit. Heated cooling water is released to the discharge canal and back to the Atlantic Ocean through existing offshore Y and multi-port diffusers.

Units 1 and 2 are also regulated under the Florida Electrical Power Plant Siting Act (License No. PA74-02).

The radioactive component of the discharge is regulated by the U.S. Nuclear Regulatory Commission under the Atomic Energy Act, and not by the Department or the U.S. Environmental Protection Agency under the Clean Water Act.

WASTEWATER TREATMENT:

Facility discharge and treatment include the following. Once-through non-contact condenser cooling water (OTCW) and auxiliary equipment cooling water (AECW) are chlorinated. Low volume waste (LVW) (consisting of water treatment system wastewater, steam generator/boiler blowdown, and equipment area floor drainage), non-radioactive wastes/liquid radiation waste, and stormwater associated with industrial activity are treated by chemical/physical processes including neutralization, settling, ion exchange and micro filtration. Non-industrial stormwater and intake screen wash water are discharged without treatment.

PERMITTEE: Florida Power & Light (FPL) PERMIT NUMBER: FL0002208 (Major)
FACILITY: St. Lucie Power Plant EXPIRATION DATE: September 28, 2016

REUSE OR DISPOSAL:

Surface Water Discharge D-001: An existing 1,487 MGD daily maximum flow, 1,362 annual average daily flow permitted discharge to the onsite discharge canal, thence to the Atlantic Ocean, Class III Marine Waters, (WBID 8103).

Internal Outfall I-003: An existing permitted discharge to the discharge canal.

Internal Outfall I-005: An existing permitted discharge to the discharge canal.

Internal Outfall I-007: An existing permitted discharge to the discharge canal.

Internal Outfall I-008: An existing permitted discharge to theIntakecanal.

Storm Water Outfall I-06B: An existing intermittent permitted storm water discharge to the intake canal via an outlet control structure.

Storm Water Outfall I-06C: An existing intermittent permitted storm water discharge to the intake canal via an outlet control structure.

Storm Water Outfall I-06D: An existing intermittent permitted storm water discharge to the intake canal via an outlet control structure.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 25 of this permit.

PERMITTEE: Florida Power & Light (FPL) PERMIT NUMBER: FL0002208 (Major)
FACILITY: St. Lucie Power Plant EXPIRATION DATE: September 28, 2016

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge once-through non-contact cooling water and auxiliary equipment cooling water from **Outfall D-001** to the Atlantic Ocean. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max	Report	Daily Maximum	Hourly	Pump Logs	FLW-1	
Temperature, Water (During Normal Operation)	Deg F	Max	Report	Daily Maximum	Hourly	Recorder	EFF-2	See I.A.4 and I.A.5
Temperature, Water (During Maintenance Activities)	Deg F	Max	117	Daily Maximum	Hourly	Recorder	EFF-2	See I.A.4 and I.A.5
Temp. Diff. between Intake and Discharge (During Normal Operation)	Deg F	Max	30	Daily Maximum	Hourly	Calculated	INT-1 EFF-2	See I.A.4 and I.A.5
Temp. Diff. between Intake and Discharge (During Maintenance Activities)	Deg F	Max	32	Daily Maximum	Hourly	Calculated	INT-1 EFF-2	See I.A.4 and I.A.5
Oxidants, Total Residual	mg/L	Max Max	0.1 0.1	Daily Maximum Monthly Average	Continuous	Recorder	EFF-2	See I.A.6 And I.A.7 And Section VI.6
Chlorination Duration	min	Max	120	Daily Maximum	Daily; 24 hours	Logs	EFF-1	and I.A.8
Nitrogen, Ammonia, Total (as N)	mg/L	Max	Report	Single Sample	Quarterly	Grab	EFF-2 INT-1	
Nitrogen, Kjeldahl, Total (as N)	mg/L	Max	Report	Single Sample	Quarterly	Grab	EFF-2 INT-1	
Nitrite plus Nitrate, Total 1 det. (as N)	mg/L	Max	Report	Single Sample	Quarterly	Grab	EFF-2 INT-1	
Nitrogen, Total	mg/L	Max	Report	Single Sample	Quarterly	Grab	EFF-2 INT-1	
Phosphorus, Total (as P)	mg/L	Max	Report	Single Sample	Quarterly	Grab	EFF-2 INT-1	
Phosphate, Ortho (as PO4)	mg/L	Max	Report	Single Sample	Quarterly	Grab	EFF-2 INT-1	
Chronic Whole Effluent Toxicity, 7-Day IC25 (Mysidopsis bahia)	percent	Min	100	Single Sample	Quarterly	24-hr TPC	EFF-2	See I.A.13
Chronic Whole Effluent Toxicity, 7-Day IC25 (Menidia beryllina)	percent	Min	100	Single Sample	Quarterly	24-hr TPC	EFF-2	See I.A.13

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-1	Pump log or recorder.
EFF-2	Within the discharge canal upstream of the discharge piping to the Atlantic Ocean.
EFF-1	Outlet corresponding to the individual condenser from Unit 1 or Unit 2.
INT-1	At plant intake structure within the intake canal.

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3. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter in such amounts as to form nuisances. *[62-302.500(1)(a)]*

4. At monitoring location EFF-2, the heated water temperature shall not exceed 113°F, before notification to the Department for power uprate completion for Units 1 and 2, or 115°F, after notification to the Department for power uprate completion for Units 1 and 2, and 30°F above ambient at any time except that the maximum discharge temperature shall be limited to 117°F and 32°F above ambient during circulating water system maintenance. In determining the temperature differential, the time of travel through the plant may be considered. The permittee shall submit with the Discharge Monitoring Report a summary of cooling water system maintenance activities and associated maximum discharge temperature reading and temperature difference above ambient. The summary will include a brief explanation of nuisance activities. In the event that discharge temperature exceeds the temperature limitations, the permittee shall notify the Department within 5 days.

   Circulating water system maintenance (including, but not limited to, condenser and/or circulating water pump maintenance) shall mean:

   a. Repair or scheduled preventive activities that maintain the facility's circulating water system and its support systems within its as-designed capacity; and

   b. Results in at least one circulating water pump being shut down, or equivalent loss of heat removal, on each unit being shut down.and in such amounts as to form nuisances.

5. Heated water from Outfall D-001 shall not cause the ocean surface temperature to exceed 97°F as an instantaneous maximum at any point extending seaward from the most seaward 18-foot depth contour line (three-fathom bottom depth contour) which is offshore from Hutchinson Island. In addition, during June, July, August, and September, no heated water from Outfall D-001 with a temperature above 92°F shall move shoreward past the 18-foot depth contour line into adjacent coastal waters. Further, no heated water with a temperature above 90°F move shoreward past the 18-foot depth contour line into coastal waters during the period October thru May.

   Heated water discharged from any port of the multi-port diffuser shall not exceed 17°F above ambient temperature in the receiving body of water outside a thermal mixing zone extending 5.50 meters seaward along the center line and 2.15 meters each side of the centerline of each port (a total area of 12 square meters for each port). Heated water discharged from the Y diffuser shall not exceed 17°F above ambient temperature in the receiving body of water outside a circular thermal mixing zone with a 13.93-meter radius originating at the mid-point between the orifices of the Y diffuser (a total area of 610 square meters for both Y diffusers). The total area of the thermal mixing zone for the facility (multi-port and Y diffusers) shall not exceed 1306 square meters.

   [62-302.520, F.A.C.]

6. Total Residual Oxidants (TRO) means the value obtained using testing procedures for Total Residual Chlorine (TRC) found in 40 CFR 136.3.

   When automated TRO monitors are operable, TRO shall not exceed a maximum instantaneous concentration of 0.1 mg/l at any one time as measured at monitoring location EFF-2.

   If automated TRO monitors are inoperable for more than 7 days, TRO monitoring shall be conducted at least one time per week on not less than three grab samples during daylight hours. Multiple grab samples shall be collected during periods of TRO discharge from condensers.

   Multiple grabs for TRO shall be defined as once per five minutes during TRO discharge periods of 30 minutes or less and once per 15 minutes for periods exceeding 30 minutes with no less than four analyses during the period of TRO discharge (sampling shall be continued until the end of the TRO discharge).

7. Neither free available chlorine (FAC), total residual oxidant (TRO), nor any other Department-approved biocide shall be discharged from any condenser for more than two hours in any one day and not more than any one

tower shall discharge FAC, TRO or other biocide at any one time. TRO and biocide monitoring shall be adequate to document compliance with this requirement. Chlorine shall not be used in conjunction with any other biocide during treatment of the condensers. *[40 CFR 423.13(b)(2)]*

8. Auxiliary equipment cooling water may receive continuous low-level chlorination.

9. The permittee shall maintain the current intake through-screen velocity such that the existing maximum velocity is not exceeded. *[C.W.A. 316(b)]*

10. The permittee shall maintain current traveling screen practices at Units 1 and 2 so as to assure that the screens are cycled twice during each 24 hours of continuous operation unless precluded by repair/maintenance requirements. *[C.W.A. 316(b)]*

11. The permittee shall develop a plan in accordance with the schedule in Condition VI.4 to help return live fish, shellfish, and other aquatic organisms collected or trapped on the intake screens to their natural habitat. Other material shall be removed from the intake screens and disposed of in accordance with all existing Federal, State and/or Local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters. *[C.W.A. 316(b)]*

12. The permittee shall monitor aquatic organism entrapment in the intake canal. The permittee shall capture and return entrained organisms in the intake canal safely and as quick as possible when practical not cause harm. The permittee shall provide a summary of these efforts with the permit renewal application. [C.W.A. 316(b)]

13. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from outfall D-001.

    a. Effluent Limitation
        (1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. [Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]
        (2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. *[Rules 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]*

    b. Monitoring Frequency
        (1) Routine toxicity tests shall be conducted once every three months, the first starting within 60 days of the issuance date of this permit and lasting for the duration of this permit.
        (2) Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation in 13.a.(1) above, the permittee may submit a written request to the Department for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 13.a.(1) above.
        (3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-014, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive valid tests for the purpose of evaluating the reduction of monitoring frequency.

    c. Sampling Requirements
        (1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-014, Section 8.
        (2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.
        (3) Samples for routine and additional follow-up tests shall not be collected on the same day.

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d. Test Requirements
(1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: **100%, 50%, 25%, 12.5%,** and **6.25%** final effluent.
(2) The permittee shall conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, **Americamysis (Mysidopsis) bahia,** Method 1007.0, and an inland silverside, **Menidia beryllina,** Method 1006.0, concurrently.
(3) All test species, procedures and quality assurance criteria used shall be in accordance with **Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms**, 3rd Edition, EPA-821-R-02-014. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In the event the above method is revised, the permittee shall conduct chronic toxicity testing in accordance with the revised method.
(4) The control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows:
(a) For the **Americamysis bahia** bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.
(b) For the **Menidia beryllina** bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.
(c) If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements
(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.
(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-014, Section 14.12 (**Americamysis bahia**) and Section 13.12 (**Menidia beryllina**). The repeat test shall begin within 21 days after the last day of the invalid test.
(3) If 100% mortality occurs in all effluent concentrations for either species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.
(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-014, Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements
(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:
(a) Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.

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(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.
(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.
(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.
(5) The same bioassay data shall not be reported as the results of more than one test.
(6) All bioassay laboratory reports shall be sent to:
Florida Department of Environmental Protection
Tallahassee Office
2600 Blair Stone Road, M.S. 3545
Tallahassee, Florida 32399-2400

g. Test Failures
(1) A test fails when the test results do not meet the limits in 13.a.(1).
(2) Additional Follow-up Tests:
(a) If a routine test does not meet the chronic toxicity limitation in 13.a.(1) above, the permittee shall notify the Department at the address above within 21 days after the last day of the failed routine test and conduct two additional follow-up tests on each species that failed the test in accordance with 13.d.
(b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.
(c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permittee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-014.
(3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permittee shall notify the Department within 21 days after the last day of the third test failure.
(a) The permittee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.
(b) The Department shall review and approve the plan before initiation.
(c) The plan shall be initiated within 30 days following the Department's written approval of the plan.
(d) Progress reports shall be submitted quarterly to the Department at the address above.
(e) During the implementation of the plan, the permittee shall conduct quarterly routine whole effluent toxicity tests in accordance with 13.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 13.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-014, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.
(f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 13.a.(1) above, the permittee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests. If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.
(4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 13.(a)(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.

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(5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

14. The withdrawal of water for the testing and functioning of the emergency cooling systems for the St. Lucie Plant from that portion of the Indian River known as Big Mud Creek shall be in accordance with the following:

a. Testing of the alternate emergency cooling systems not to exceed 4,000,000 gallons per calendar year.

b. Flow of water in the alternate emergency cooling system, in the event that the main source of emergency cooling water from the Atlantic Ocean is not available, shall not exceed 60,000 gallons per minute, and may continue until the main source of emergency cooling water has been restored.

c. The permittee shall notify the Southeast District Office of the Department prior to each test of the emergency cooling canal system, and shall also notify the Department of any use of the emergency cooling canal system lasting more than twelve hours.

d. Starting with the issuance of this permit, all pertinent flow and length of time information associated with withdrawal of water from Big Mud Creek shall be kept on site in accordance with permit Condition V.2 and made available to Department inspectors upon request.

B. Internal Outfalls

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge process wastewater and monitoring well sample purge water from **Internal Outfall I-003** to the onsite discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Per batch of process	Calculated	OUI-1	
Oil and Grease	mg/L	Min Max	15.0 20.0	Monthly Average Daily Maximum	Annually	Grab	OUI-1	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Per batch of process	Grab	OUI-1	

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
OUI-1	Discharge from the radiation waste system prior to mixing with any other waste. stream.

3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge steam generator blowdown from **Internal Outfall I-005** to the onsite discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

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			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Weekly, when discharging	Calculated	OUI-2	See I.B.5
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Weekly, when discharging	Grab	OUI-2	See I.B.5
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Weekly, when discharging	Grab	OUI-2	See I.B.5
Hydrazine	mg/L	Max	0.30	Daily Maximum	Weekly, when discharging	Grab	EFF-2	See I.B.5, I.B.6, and I.B.7
Carbohydrazide	mg/L	Max	Report	Daily Maximum	Weekly, when discharging	Grab	EFF-2	See I.B.5, I.B.6, and I.B.7

4. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.3. and as described below:

Monitoring Site Number	Description of Monitoring Site
OUI-2	Discharge from I-005 prior to entering the discharge canal.
EFF-2	Within the discharge canal upstream of the discharge piping to the Atlantic Ocean.

5. Internal Outfall I-005 shall be monitored once per discharge event or once per week when discharging, whichever is more frequent, unless there is no discharge for that week. Total volume of batch and period of discharge shall be reported.

6. Hydrazine and Carbohydrazide shall be monitored once per batch by a grab sample during wet lay-up discharges that result from the start-up of a unit following a refueling outage.

7. A grab sample shall be taken at the discharge of the steam generator to the discharge canal and the following calculations shall be used to determine the concentration from the discharge canal to the Atlantic Ocean [point of discharge (POD)].

$$\text{Hydrazine at POD (mg/L)} = \frac{\text{Steam Generator Flow (MGD) x Blowdown Hydrazine Concentration (mg/L)}}{\text{Once-Through Cooling Water Flow (MGD)}}$$

$$\text{Carbohydrazide at POD (mg/L)} = \frac{\text{Steam Generator Flow (MGD) x Blowdown Carbohydrazide Concentration (mg/L)}}{\text{Once-Through Cooling Water Flow (MGD)}}$$

8. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge stormwater from **Internal Outfall I-008** to the intake canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Weekly, when discharging	Calculated	OUI-5	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Weekly, when discharging	Grab	OUI-5	

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			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Weekly, when discharging	Grab	OUI-5	

9. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.8. and as described below:

Monitoring Site Number	Description of Monitoring Site
OUI-5	Storm water discharge prior to entering the intake canal.

10. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge stormwater associated with industrial activity from the Former Oil Storage Area from **Internal Outfall I-06B** to the intake canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Annually	Calculated	OUI-3	
Solids, Total Suspended	mg/L	Max	Report	Daily Maximum	Annually	Grab	OUI-3	
Oil and Grease	mg/L	Max	Report	Daily Maximum	Annually	Grab	OUI-3	

11. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.10. and as described below:

Monitoring Site Number	Description of Monitoring Site
OUI-3	Discharge from the former oil storage area prior to entering the intake canal.

12. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge storm water not associated with industrial activity from **Internal Outfall I-06C** to the mangrove impoundment. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Annually	Calculated	OUI-4	
Oil and Grease	mg/L	Max	Report	Daily Maximum	Annually	Grab	OUI-4	

13. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.12. and as described below:

Monitoring Site Number	Description of Monitoring Site
OUI-4	Stormwater discharge prior to entering the mangrove impoundment area.

14. Discharge of intake screen wash water from Internal Outfall I-007 is permitted without limitation or monitoring requirements.

15. Discharge of storm water and wash-down water consisting of potable water with no chemical additives discharge from Spent Nuclear Fuel Dry Storage Area to the intake canal through Internal Outfall I-06D is permitted without limitations or monitoring requirements.

C. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in 62-302, F.A.C.; and

   c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

   When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

   Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

3. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e., monthly, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	Due Date
Monthly	first day of month - last day of month	28th day of following month
Quarterly	January 1 - March 31	April 28

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	April 1 - June 30 July 1 - September 30 October 1 - December 31	July 28 October 28 January 28
Semiannual	January 1 - June 30 July 1 - December 30	July 28 January 28
Annual	January 1 - December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge. The permittee may submit either paper or electronic DMR form(s). If submitting paper DMR form(s), the permittee shall make copies of the attached DMR form(s). If submitting electronic DMR form(s), the permittee shall use a Department-approved electronic DMR system.

The electronic submission of DMR forms shall accepted only if approved in writing by the Department. For purposes of determining compliance with this permit, data submitted in electronic format is legally equivalent to data submitted on signed and certified DMR forms.

The permittee shall submit the completed DMR form(s) to the Department by the twenty-eighth (28th) of the month following the month of operation at the addresses specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

And

Florida Department of Environmental Protection
Southeast District Office
Industrial Wastewater Section
1801 SE Hill Moor Drive, Suite C-204
Port St. Lucie, Florida 34952
(772) 871-7662

[62-620.610(18)]

4. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Southeast District Office at the address specified below:

   Florida Department of Environmental Protection
   Southeast District Office
   Industrial Wastewater Program
   1801 SE Hill Moor Drive, Suite C-204
   Port St. Lucie, Florida 34952
   (772) 871-7662

   [62-620.305]

5. All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. *[62-620.305]*

6. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

7. Bypasses subject to General Conditions IX.20 and IX.22 shall be monitored or estimated daily, or as approved by the Department for flow and other parameters required for the specific outfall that is bypassed. Monitoring results shall be reported to the Department.

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8. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit. A permit revision from the Department shall be required prior to the use of any biocide or chemical additive used in the cooling system (except chlorine as authorized elsewhere in this permit) or any other portion of the treatment system which may be toxic to aquatic life. The permit revision request shall include:

   a. Name and general composition of biocide or chemical

   b. Frequencies of use

   c. Quantities to be used

   d. Proposed effluent concentrations

   e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA-821-R-02-012 EP entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)

   f. Product data sheet

   g. Product label

   The Department shall review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without a permit revision by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

9. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. *[40 CFR Part 423.12(b)(2)]*

10. The permittee is authorized to use the following chemicals and biocides as previously approved:

Chemical Name	System Used
Ammonium Hydroxide	Feedwater, Condensate, Steam Generators
Carbohydrazide	Steam Generators
Boric Acid (Boron)	Reactor Coolant (RCS) and Support Systems
Dimethylamine	Feedwater, Condensate, Steam Generators
Hydrazine	Feedwater, Condensate, Steam Generators-Small quantities to RCS during cold startups
Sodium Molybdate	Closed Cooling Systems
Sodium Nitrite	Closed Cooling Systems
Tolytriazole	Closed Cooling Systems
Glutaraldehyde	Closed Cooling Systems
Isothiazolin	Closed Cooling Systems
Polyglycol	Closed Cooling Systems
Sodium Hypochlorite	Circulating Water and Intake Cooling (Auxiliary Equipment Cooling Water)
Ethanolamine (ETA)	Feedwater, Condensate, Steam Generators
Klaraid	Liquid Rad Waste System
Hydrogen Peroxide	RCS
Zinc Acetate	RCS
Potassium Hydroxide	Closed Cooling Systems
Sodium Hydroxide	Closed Cooling Systems
Lithium Hydroxide	RCS

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11. The permittee is authorized to use preservative-free wood flour for plugging pinhole leaks in the once through cooling water system condenser.

II. SLUDGE MANAGEMENT REQUIREMENTS

1. The permitee shall be responsible for proper treatment, management, use, and disposal of its sludge. *[62-620.320(6)]*

2. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in accordance with requirements of Chapter 62-730, F.A.C. *[62-730]*

3. Vegetation and materials removed from intake screens s must be properly stored onsite until they are disposed in accordance with requirements in Chapter 62-701, F.A.C., and other applicable State and Federal requirements. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in accordance with requirements of Chapter 62-730, F.A.C. *[62-730]*

III. GROUND WATER REQUIREMENTS

Section III is not applicable to this facility.

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

Section IV is not applicable to this facility.

V. OPERATION AND MAINTENANCE REQUIREMENTS

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports required by the permit for at least three years from the date the report was prepared;

   c. Records of all data, including reports and documents, used to complete the application for the permit for at least three years from the date the application was filed;

   d. A copy of the current permit;

   e. A copy of any required record drawings; and

   f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules.

   [62-620.350]

VI. SCHEDULES

1. In accordance with section 403.088(2)(e) and (f), Florida Statues, a compliance schedule for this facility is contained in Administrative Order AO022TL which is hereby incorporated by reference.

2. The following improvement actions shall be completed according to the following schedule. The Storm water Pollution Prevention Plan (SWPPP) shall be prepared and implemented in accordance with Part VII of this permit.

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Improvement Action	Completion Date
1. Develop and implement SWPPP	18 months from permit issuance.
2. Complete Plan Summary	2 years from permit issuance.
3. Progress/Update Report	3 years, and then annual thereafter.

[62-620.320(6)]

3. If the permittee wishes to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C. *[62-620.335(1) and (2)]*

4. Within six months of the completion of both uprate projects for Units 1 and 2, the permittee shall schedule a meeting with the Department to discuss the contents of the aquatic organism return plan in accordance with Condition I.A.11 and shall submit the plan to the Department six months thereafter. The plan shall be implemented within 24 months subsequent to approval by the Department. However, if the final 316(b) rule for existing facilities prescribes alternative means and schedules than that described above, the permittee shall, within six months after the effective date of the rule, submit to the Department a new plan and schedule for complying with 316(b) requirements.

5. The permittee shall notify the Department upon completion of the power uprate for Units 1 and 2. The permittee shall submit a notification letter to the Department at the following addresses:

   Florida Department of Environmental Protection
   Industrial Wastewater Section, Mail Station 3545
   2600 Blair Stone Road
   Tallahassee, Florida 32399-2400

   and

   Florida Department of Environmental Protection
   Southeast District Office
   Industrial Wastewater Program
   1801 SE Hill Moor Drive, Suite C-204
   Port St. Lucie, Florida 34952

6. No later than 90 days after the effective date of this Order, the Permittee shall prepare and submit for the Department's review and approval a plan of study (Total Residual Oxidants POS) that includes a schedule. The Total Residual Oxidants POS shall be designed and implemented to reaffirm that the discharge from the diffusers meets the total residual oxidants Class III marine water quality standard of 0.1 mg/L. The study shall last no less than 24 months from commencement. The results of the study shall be submitted in a report (Total Residual Oxidants Report) to the Department for review and approval no later than 60 days after the approved Total Residual Oxidants POS completion date. The schedule shall include milestones and the completion date.

   In the event that the Total Residual Oxidants Report fails to demonstrate that the discharge from the diffusers meets the total residual oxidants Class III marine water quality standard, the permittee shall prepare a feasibility study report (Engineering Report) for the evaluation of engineering options to achieve the water quality standard. The Engineering Report shall be submitted to the Department for review and approval no later than 90 days after the approved Total Residual Oxidants POS completion date. The options shall be ranked based on equal weighting of technical and economic feasibility. The results of the ranking shall be presented in the Engineering Report. In addition, the Engineering Report shall include a plan and schedule for implementing the highest ranked option. The schedule shall include milestones and the completion date. The implementation shall take no longer than 24 months from Department approval.

   The permittee shall provide status reports every six months following the approval of the Total Residual Oxidants POS and Engineering Report, until compliance is reaffirmed. The status reports shall document accomplishment of milestones established by the schedules.

APPENDIX I

ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS 42-1P THROUGH 42-8P
JANUARY 2013 – DECEMBER 2013

TJK-3
DOCKET NO. 120007-EI
FPL WITNESS: T.J. KEITH
EXHIBIT _____
PAGES 1-112

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 14
PARTY Florida Power & Light Co.
DESCRIPTION T.J. Keith (TJK-3), Appendix I, Env. Cost Rec. proj. 1/-12/13, Form 42-1P-42-8P

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

FORM: 42-1P

(1)	(2)	(3)	(4)	(5)
	Energy	CP Demand	GCP Demand	Total
1. Total Jurisdictional Revenue Requirements for the projected period				
a. Projected O&M Activities	$18,093,629	$12,023,609	$1,636,146	$31,753,383
b. Projected Capital Projects	$35,838,468	$147,440,643	$0	$183,279,110
c. Total Jurisdictional Revenue Requirements	$53,932,097	$159,464,251	$1,636,146	$215,032,494
2. True-up for Estimated Over/(Under) Recovery	$1,485	$6,083	$52	$7,620
3. Final True-up Over/(Under)	$189,521	$777,427	$9,965	$976,912
4. Total Jurisdictional Amount to be Recovered/(Refunded)	$53,741,091	$158,680,741	$1,626,130	$214,047,962
5. Total Projected Jurisdictional Amount Adjusted for Taxes	$53,779,784	$158,794,992	$1,627,300	$214,202,076

Note: Allocation to energy and demand in each period are in proportion to the respective period split of costs.

True-up costs are split in proportion to the split of actual demand-related and energy-related costs from respective true-up periods.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

FORM: 42-2P

O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
PROJECT #	Monthly Data													Method of Classification		
	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount	Energy	CP Demand	GCP Demand
1. Description of O&M Activities																
1 - Air Operating Permit Fees	$24,083	$24,083	$24,083	$24,083	$24,083	$24,083	$24,083	$24,083	$24,083	$24,083	$24,083	$24,087	$289,000	$269,000		
3a - Continuous Emission Monitoring Systems	$155,194	$190,079	$37,329	$30,579	$30,579	$45,329	$155,194	$30,579	$37,326	$30,578	$30,575	$43,055	$816,396	$816,396		
5e - Maintenance of Stationary Above Ground Fuel Storage Tanks	$84,500	$55,500	$756,836	$268,005	$251,200	$900,000	$200,000	$222,000	$850,000	$0	$0	$0	$3,588,041		$3,588,041	
6a - Oil Spill Clean-up/Response Equipment	$12,049	$12,049	$42,715	$12,049	$47,049	$42,715	$12,048	$12,048	$42,715	$22,330	$22,048	$12,048	$291,883	$291,883		
13 - RCRA (Resource Conservation & Recovery Act) Corrective Action	$4,166	$4,166	$4,166	$4,166	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$50,000		$50,000	
14 - NPDES Permit Fees	$115,200	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$115,200		$115,200	
17a - Disposal of Non-Containerized Liquid Waste	$30,000	$30,000	$36,000	$62,500	$0	$0	$0	$2,500	$0	$0	$0	$0	$161,000	$161,000		
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$159,688	$159,688	$159,688	$159,686	$159,688	$159,688	$159,688	$159,686	$159,688	$159,688	$159,688	$159,694	$1,916,262			$1,916,262
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$101,817	$101,817	$101,817	$101,817	$101,817	$101,817	$101,817	$101,817	$101,817	$101,817	$101,817	$101,828	$1,221,815	$93,986	$1,127,829	
19c - Substation Pollutant Discharge Prevention & Removal - Costs in Base Rates	($46,686)	($46,686)	($46,686)	($46,666)	($46,686)	($46,686)	($46,686)	($46,666)	($46,666)	($46,686)	($46,686)	($46,686)	($560,232)	($21,547)	($258,569)	($280,116)
NA - Amortization of Gains on Sales of Emissions Allowances	($46,048)	($46,048)	($46,048)	($46,048)	($46,718)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	($554,186)	($554,186)		
22 - Pipeline Integrity Management	$0	$0	$15,000	$150,000	$11,000	$0	$30,000	$0	$7,500	$40,000	$40,000	$0	$293,500		$293,500	
23 - SPCC - Spill Prevention, Control & Countermeasures	$76,045	$75,466	$75,466	$75,466	$77,307	$75,467	$75,467	$76,044	$75,467	$77,307	$86,287	$85,461	$931,256		$931,256	
24 - Manatee Reburn	$41,667	$41,667	$41,667	$41,667	$41,667	$41,667	$41,667	$41,667	$41,667	$41,667	$41,667	$41,663	$500,000	$500,000		
25 - Pt. Everglades ESP Technology	$24,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,000	$24,000		
27 - Lowest Quality Water Source	$27,442	$27,442	$27,442	$27,442	$27,442	$27,442	$27,442	$27,443	$27,443	$27,443	$27,443	$27,443	$329,309		$329,309	
28 - CWA 316(b) Phase II Rule	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$8,775	$8,775	$8,775	$16,775	$107,504	$107,504	$264,108		$264,108	
29 - SCR Consumables	$29,166	$29,188	$29,166	$29,166	$29,166	$29,166	$29,166	$29,166	$29,166	$29,166	$29,166	$29,174	$350,000	$350,000		
30 - HBMP	$1,833	$1,833	$1,833	$1,833	$1,833	$1,833	$1,833	$1,833	$1,833	$1,833	$1,833	$1,837	$22,000		$22,000	
31 - Clean Air Interstate Rule (CAIR) Compliance	$672,838	$672,838	$692,838	$710,638	$711,838	$691,838	$692,836	$757,960	$777,960	$757,960	$777,960	$757,986	$8,675,688	$8,675,688		
33 - MATS Project	$250,250	$250,250	$250,250	$250,250	$250,250	$250,250	$250,250	$250,250	$250,250	$250,250	$250,250	$250,250	$3,003,000	$3,003,000		
35 - Martin Plant Drinking Water System Compliance	$0	$0	$5,000	$0	$0	$5,000	$0	$0	$5,000	$0	$0	$5,000	$20,000		$20,000	
37 - DeSoto Next Generation Solar Energy Center	$98,331	$81,851	$154,001	$108,881	$81,301	$92,651	$87,001	$88,851	$86,831	$82,151	$86,301	$82,151	$1,127,902		$1,127,902	
38 - Space Coast Next Generation Solar Energy Center	$25,956	$26,856	$37,386	$27,071	$26,356	$36,966	$26,456	$30,456	$29,356	$26,966	$26,356	$32,955	$353,176		$353,176	
39 - Martin Next Generation Solar Energy Center	$258,801	$258,801	$258,801	$258,801	$258,801	$258,801	$258,801	$258,801	$258,801	$258,801	$258,801	$258,801	$3,105,612		$3,105,612	
40 - Greenhouse Gas Reduction Program	$0	$0	$0	$8,500	$0	$0	$0	$0	$0	$0	$0	$0	$8,500	$8,500		
41 - Manatee Temporary Heating System	$152,967	$142,218	$107,250	$96,263	$44,371	$33,365	$33,365	$33,365	$34,878	$29,962	$110,000	$112,000	$930,000	$930,000		
42 - Turkey Point Cooling Canal Monitoring Plan	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$2,442,000	$2,442,000		
45 - 800 MW Unit ESP	$85,000	$85,000	$85,000	$85,000	$85,000	$85,000	$85,000	$170,000	$170,000	$170,000	$170,000	$172,087	$1,447,087	$1,447,087		
46 - SL Lucie Cooling Water Discharge Monitoring	$27,334	$25,715	$59,044	$11,334	$43,854	$25,715	$45,473	$9,715	$59,854	$10,525	$43,044	$27,334	$388,941		$388,941	
47 - NPDES Permit Renewal Requirements	$0	$2,200	$15,200	$0	$6,800	$10,000	$18,500	$18,500	$5,200	$10,000	$25,100	$0	$113,500		$113,500	
48 - Industrial Boiler MACT	$0	$0	$0	$0	$0	$0	$0	$0	$1,000	$0	$0	$0	$1,000		$1,000	
49 - Thermal Discharge Standards	$0	$35,000	$0	$35,000	$0	$35,000	$0	$35,000	$0	$35,000	$0	$0	$175,000		$175,000	
50 - Steam Electric Effluent Guidelines Revised Rules	$0	$0	$45,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$45,000		$45,000	
51 - Gopher Tortoise Relocations	$0	$0	$0	$0	$0	$0	$0	$37,500	$0	$0	$0	$0	$37,500		$37,500	
52 - Numeric Nutrient Criteria Water Quality Standards in Florida	$0	$0	$442,400	$0	$0	$0	$0	$0	$0	$0	$0	$0	$442,400		$442,400	
2. Total of O&M Activities	$2,570,093	$2,445,250	$3,817,145	$2,692,166	$2,428,865	$3,089,612	$2,479,663	$2,540,640	$3,201,409	$2,319,121	$2,534,702	$2,447,177	$32,365,640	$18,456,789	$12,272,706	$1,636,146

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

FORM: 42-2P

O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total of O&M Activities	$2,570,093	$2,445,250	$3,617,145	$2,692,166	$2,428,665	$3,089,612	$2,479,663	$2,540,640	$3,201,409	$2,319,121	$2,534,702	$2,447,177	$32,365,640
3. Recoverable Costs Allocated to Energy	$1,640,702	$1,640,836	$1,509,786	$1,514,383	$1,426,821	$1,406,767	$1,486,965	$1,514,972	$1,571,399	$1,519,350	$1,619,103	$1,605,705	$18,456,789
4a. Recoverable Costs Allocated to CP Demand	$793,046	$668,070	$1,971,015	$1,041,439	$865,499	$1,546,500	$856,353	$889,323	$1,493,665	$663,426	$779,254	$705,121	$12,272,706
4b. Recoverable Costs Allocated to GCP Demand	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,351	$1,636,146
5. Retail Energy Jurisdictional Factor	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	
6a. Retail CP Demand Jurisdictional Factor	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	
6b. Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7. Jurisdictional Energy Recoverable Costs	$1,608,419	$1,608,550	$1,480,079	$1,484,586	$1,398,747	$1,379,087	$1,457,707	$1,485,163	$1,540,460	$1,489,455	$1,587,245	$1,574,111	$18,093,629
8a. Jurisdictional CP Demand Recoverable Costs	$776,949	$654,510	$1,931,009	$1,020,301	$847,932	$1,515,110	$838,971	$871,272	$1,463,348	$649,960	$763,437	$690,809	$12,023,609
8b. Jurisdictional GCP Demand Recoverable Costs	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,345	$136,351	$1,636,146
9. Total Jurisdictional Recoverable Costs for O&M Activities	$2,521,714	$2,399,405	$3,547,433	$2,641,231	$2,383,024	$3,030,543	$2,433,023	$2,492,780	$3,140,173	$2,275,760	$2,487,027	$2,401,271	$31,753,383

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

FORM: 42-3P

CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
PROJECT #	Monthly Data													Method of Classification	
	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount	Energy	Demand
1. Description of Investment Projects [a]															
2 - Low NOX Burner Technology	$15,024	$15,196	$15,118	$15,039	$14,961	$14,883	$14,804	$14,726	$14,648	$14,569	$14,491	$14,413	$177,872	$177,872	
3b - Continuous Emission Monitoring Systems	$42,429	$41,231	$41,081	$40,932	$42,216	$43,497	$43,340	$43,648	$43,955	$44,947	$45,936	$45,772	$518,983	$518,983	
4b - Clean Closure Equivalency	$118	$106	$106	$108	$105	$105	$105	$104	$104	$104	$103	$103	$1,270	$98	$1,172
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	$77,293	$76,269	$78,103	$75,937	$75,771	$75,606	$75,440	$75,274	$75,108	$74,942	$74,777	$74,611	$907,131	$69,779	$837,352
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$123	$123	$122	$122	$121	$121	$120	$120	$119	$119	$118	$118	$1,447	$111	$1,335
8b - Oil Spill Clean-up/Response Equipment	$14,416	$12,954	$13,132	$13,308	$13,587	$13,788	$13,415	$13,205	$13,229	$12,903	$12,780	$12,902	$159,618	$12,278	$147,340
10 - Relocate Storm Water Runoff	$661	$660	$659	$657	$656	$654	$653	$652	$650	$649	$646	$646	$7,846	$604	$7,242
12 - Scherer Discharge Pipeline	$4,451	$4,438	$4,425	$4,413	$4,400	$4,387	$4,375	$4,362	$4,349	$4,337	$4,324	$4,311	$52,573	$4,044	$48,529
20 - Wastewater Discharge Elimination & Reuse	$8,105	$6,989	$6,975	$6,962	$6,948	$6,935	$6,921	$6,908	$6,895	$6,881	$6,868	$6,854	$84,240	$6,480	$77,760
NA - Amortization of Gains on Sales of Emissions Allowances	($9,151)	($8,793)	($8,435)	($8,078)	($7,730)	($7,381)	($7,022)	($6,683)	($6,304)	($5,945)	($5,586)	($5,227)	($86,317)	($66,317)	
21 - St. Lucie Turtle Nets	$8,716	$8,711	$8,707	$8,703	$8,699	$8,695	$8,691	$8,687	$8,683	$8,679	$8,674	$24,769	$120,414	$9,263	$111,151
22 - Pipeline Integrity Management	$28,468	$28,427	$28,386	$28,583	$28,779	$28,737	$28,696	$28,654	$28,612	$28,571	$28,529	$28,487	$342,928	$26,379	$316,549
23 - SPCC - Spill Prevention, Control & Countermeasures	$138,391	$127,057	$126,868	$128,815	$130,757	$130,559	$130,361	$130,206	$130,050	$129,852	$129,653	$129,455	$1,582,026	$120,156	$1,441,870
24 - Manatee Reburn	$263,800	$263,275	$262,751	$262,226	$261,701	$261,178	$260,651	$260,126	$259,601	$259,076	$256,551	$258,026	$3,130,961	$3,130,961	
25 - Pt. Everglades ESP Technology	$1,973,809	$1,811,064	$1,800,725	$1,790,385	$1,780,046	$1,769,707	$1,759,368	$1,749,029	$1,738,689	$1,728,350	$1,716,011	$1,707,672	$21,326,855	$21,326,855	
26 - UST Remove/Replacement	$918	$916	$915	$913	$911	$910	$908	$907	$905	$904	$902	$900	$10,909	$839	$10,070
31 - Clean Air Interstate Rule (CAIR) Compliance	$5,003,021	$4,999,003	$4,999,318	$4,999,097	$4,998,913	$4,996,527	$4,990,997	$4,984,367	$4,977,492	$4,970,390	$4,963,372	$4,957,444	$59,839,942	$4,803,072	$55,236,869
33 - MATS Project	$1,005,961	$1,004,900	$1,004,363	$1,003,501	$1,002,541	$1,001,549	$1,000,615	$999,624	$998,580	$997,541	$996,504	$995,480	$12,011,159	$923,935	$11,087,224
34 - St Lucie Cooling Water System Inspection & Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,946	$17,946	$1,380	$16,565
35 - Martin Plant Drinking Water System Compliance	$2,095	$2,092	$2,089	$2,086	$2,082	$2,079	$2,076	$2,073	$2,070	$2,066	$2,063	$2,060	$24,932	$1,918	$23,014
36 - Low-Level Radioactive Waste Storage	$58,364	$58,289	$58,214	$58,139	$58,063	$57,988	$57,913	$57,838	$57,762	$57,687	$57,612	$108,284	$744,133	$57,241	$686,892
37 - DeSoto Next Generation Solar Energy Center	$1,405,342	$1,401,788	$1,398,287	$1,394,785	$1,391,231	$1,387,676	$1,384,122	$1,380,568	$1,377,013	$1,373,459	$1,369,905	$1,366,350	$16,630,525	$1,279,271	$15,351,254
38 - Space Coast Next Generation Solar Energy Center	$866,615	$864,962	$863,310	$861,556	$859,937	$858,417	$856,765	$855,112	$853,460	$851,807	$850,154	$848,502	$7,890,598	$606,969	$7,283,629
39 - Martin Next Generation Solar Energy Center	$3,949,243	$3,939,421	$3,936,399	$3,945,848	$3,948,459	$3,938,562	$3,936,437	$3,949,057	$3,953,857	$3,943,865	$3,933,673	$3,923,880	$47,298,902	$3,636,377	$43,660,525
41 - Manatee Temporary Heating System	$105,251	$105,820	$105,757	$105,817	$105,858	$105,925	$106,013	$106,052	$106,046	$106,081	$106,162	$106,199	$1,270,763	$97,753	$1,173,031
42 - Turkey Point Cooling Canal Monitoring Plan	$32,172	$32,131	$32,089	$32,047	$32,005	$31,963	$31,922	$31,880	$31,838	$31,798	$31,755	$31,713	$383,311	$29,485	$353,825
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$1,526	$1,524	$1,522	$1,520	$1,517	$1,515	$1,513	$1,511	$1,508	$1,506	$1,504	$1,502	$18,168		$18,168
45 - 800 MW Unit ESP	$827,055	$856,429	$876,367	$891,068	$905,816	$927,577	$971,067	$1,082,080	$1,204,276	$1,298,006	$1,362,092	$1,400,038	$12,603,853		$12,603,853
2. Total Investment Projects - Recoverable Costs	$15,624,217	$15,456,782	$15,455,351	$15,464,487	$15,468,352	$15,462,158	$15,480,266	$15,580,088	$15,683,200	$15,743,140	$15,773,775	$15,861,193	$187,053,006	$36,557,787	$150,495,219

[a] Each project's Total System Recoverable Expenses on Form 42-4P, Line 9.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

FORM: 42-3P

CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total Investment Projects - Recoverable Costs	$15,624,217	$15,456,782	$15,455,351	$15,464,487	$15,468,352	$15,462,158	$15,480,266	$15,580,086	$15,683,200	$15,743,140	$15,773,775	$15,861,193	$187,053,006
3. Recoverable Costs Allocated to Energy	$3,246,196	$3,081,577	$3,070,179	$3,059,843	$3,050,412	$3,039,665	$3,027,799	$3,017,454	$3,006,498	$2,995,046	$2,983,616	$2,977,502	$36,557,787
4. Recoverable Costs Allocated to Demand	$12,376,019	$12,375,205	$12,385,172	$12,404,644	$12,417,940	$12,422,493	$12,452,467	$12,562,632	$12,676,702	$12,748,095	$12,790,158	$12,883,691	$150,495,219
5. Retail Energy Jurisdictional Factor	98.03238%	98.03238%	96.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	
6. Retail Demand Jurisdictional Factor	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	
7. Jurisdictional Energy Recoverable Costs [a]	$3,184,286	$3,020,943	$3,009,769	$2,999,636	$2,990,391	$2,979,855	$2,968,223	$2,958,082	$2,947,342	$2,936,114	$2,924,910	$2,918,916	$35,838,468
8. Jurisdictional Demand Recoverable Costs [b]	$12,124,825	$12,124,028	$12,133,792	$12,152,869	$12,165,896	$12,170,356	$12,199,721	$12,307,650	$12,419,405	$12,489,349	$12,530,559	$12,622,193	$147,440,643
9. Total Jurisdictional Recoverable Costs for Investment Projects	$15,309,110	$15,144,971	$15,143,562	$15,152,506	$15,156,287	$15,150,211	$15,167,944	$15,265,732	$15,366,747	$15,425,463	$15,455,469	$15,541,109	$183,279,110

[a] Line 3 x Line 5

[b] Line 4 x Line 6

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2 - Low NOX Burner Technology														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($5,058,205)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5,058,205)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		($5,122,577)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5,122,577)
2. Plant-In-Service/Depreciation Base [a]	$9,896,803	$4,838,598	$4,838,598	$4,838,598	$4,838,598	$4,838,598	$4,838,598	$4,838,598	$4,838,598	$4,838,598	$4,838,598	$4,838,598	$4,838,598	N/A
3. Less: Accumulated Depreciation	$9,287,850	$4,175,354	$4,185,434	$4,195,515	$4,205,595	$4,215,675	$4,225,756	$4,235,836	$4,245,917	$4,255,997	$4,266,077	$4,276,158	$4,286,238	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$608,952	$663,244	$653,164	$643,084	$633,003	$622,923	$612,842	$602,762	$592,682	$582,601	$572,521	$562,440	$552,360	N/A
6. Average Net Investment		$636,098	$658,204	$648,124	$638,043	$627,963	$617,883	$607,802	$597,722	$587,641	$577,561	$567,481	$557,400	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$4,036	$4,176	$4,112	$4,048	$3,984	$3,920	$3,856	$3,792	$3,728	$3,664	$3,600	$3,536	$46,453
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$908	$940	$925	$911	$897	$882	$868	$853	$839	$825	$810	$796	$10,454
8. Investment Expenses														
a. Depreciation [d]		$10,080	$10,080	$10,080	$10,080	$10,080	$10,080	$10,080	$10,080	$10,080	$10,080	$10,080	$10,080	$120,965
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$15,024	$15,196	$15,118	$15,039	$14,961	$14,883	$14,804	$14,726	$14,648	$14,569	$14,491	$14,413	$177,872

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
3b - Continuous Emission Monitoring Systems														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($2,159,043)	$0	$0	$0	$257,000	$0	$0	$88,500	$0	$212,000	$0	$0	($1,601,543)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		($1,889,200)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,889,200)
2. Plant-In-Service/Depreciation Base [a]	$9,368,408	$7,209,364	$7,209,364	$7,209,364	$7,209,364	$7,466,364	$7,466,364	$7,466,364	$7,554,864	$7,554,864	$7,766,864	$7,766,864	$7,766,864	N/A
3. Less: Accumulated Depreciation	$6,239,593	$4,369,628	$4,388,863	$4,408,098	$4,427,332	$4,447,004	$4,467,112	$4,487,220	$4,507,448	$4,527,797	$4,548,474	$4,569,477	$4,590,481	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$3,128,815	$2,839,736	$2,820,501	$2,801,267	$2,782,032	$3,019,361	$2,999,252	$2,979,144	$3,047,416	$3,027,067	$3,218,391	$3,197,387	$3,176,383	N/A
6. Average Net Investment		$2,984,275	$2,830,119	$2,810,884	$2,791,649	$2,900,696	$3,009,307	$2,989,198	$3,013,280	$3,037,241	$3,122,729	$3,207,889	$3,186,885	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$18,933	$17,955	$17,833	$17,711	$18,403	$19,092	$18,964	$19,117	$19,269	$19,812	$20,352	$20,219	$227,661
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$4,261	$4,041	$4,013	$3,986	$4,142	$4,297	$4,268	$4,302	$4,337	$4,459	$4,580	$4,550	$51,235
8. Investment Expenses														
a. Depreciation [d]		$19,235	$19,235	$19,235	$19,235	$19,671	$20,108	$20,108	$20,229	$20,349	$20,676	$21,004	$21,004	$240,087
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$42,429	$41,231	$41,081	$40,932	$42,216	$43,497	$43,340	$43,648	$43,955	$44,947	$45,936	$45,772	$518,983

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
4b - Clean Closure Equivalency														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($19,812)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($19,812)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		($16,767)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($16,767)
2. Plant-In-Service/Depreciation Base [a]	$41,612	$21,799	$21,799	$21,799	$21,799	$21,799	$21,799	$21,799	$21,799	$21,799	$21,799	$21,799	$21,799	N/A
3. Less: Accumulated Depreciation	$29,759	$13,031	$13,069	$13,107	$13,145	$13,183	$13,221	$13,259	$13,297	$13,336	$13,374	$13,412	$13,450	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$11,852	$8,769	$8,731	$8,692	$8,654	$8,616	$8,578	$8,540	$8,502	$8,464	$8,426	$8,387	$8,349	N/A
6. Average Net Investment		$10,310	$8,750	$8,712	$8,673	$8,635	$8,597	$8,559	$8,521	$8,483	$8,445	$8,406	$8,368	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$65	$56	$55	$55	$55	$55	$54	$54	$54	$54	$53	$53	$663
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$15	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$149
8. Investment Expenses														
a. Depreciation [d]		$38	$38	$38	$38	$38	$38	$38	$38	$38	$38	$38	$38	$458
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$118	$106	$106	$106	$105	$105	$105	$104	$104	$104	$103	$103	$1,270

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

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ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($1,132,078)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,132,078)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		($911,263)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($911,263)
2. Plant-In-Service/Depreciation Base [a]	$11,351,926	$10,219,848	$10,219,848	$10,219,848	$10,219,848	$10,219,848	$10,219,848	$10,219,848	$10,219,848	$10,219,848	$10,219,848	$10,219,848	$10,219,848	N/A
3. Less: Accumulated Depreciation	$4,031,083	$3,141,156	$3,162,491	$3,183,827	$3,205,162	$3,226,497	$3,247,833	$3,269,168	$3,290,504	$3,311,839	$3,333,174	$3,354,510	$3,375,845	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$7,320,843	$7,078,692	$7,057,357	$7,038,022	$7,014,686	$6,993,351	$6,972,015	$6,950,680	$6,929,345	$6,908,009	$6,886,674	$6,865,338	$6,844,003	N/A
6. Average Net Investment		$7,199,768	$7,068,025	$7,046,689	$7,025,354	$7,004,019	$6,982,683	$6,961,348	$6,940,012	$6,918,677	$6,897,341	$6,876,006	$6,854,671	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$45,678	$44,842	$44,706	$44,571	$44,436	$44,300	$44,165	$44,030	$43,894	$43,759	$43,624	$43,488	$531,493
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$10,280	$10,092	$10,061	$10,031	$10,000	$9,970	$9,939	$9,909	$9,878	$9,848	$9,818	$9,787	$119,613
8. Investment Expenses														
a. Depreciation [d]		$21,335	$21,335	$21,335	$21,335	$21,335	$21,335	$21,335	$21,335	$21,335	$21,335	$21,335	$21,335	$256,025
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$77,293	$76,269	$76,103	$75,937	$75,771	$75,606	$75,440	$75,274	$75,108	$74,942	$74,777	$74,611	$907,131

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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. Plant-In-Service/Depreciation Base [a]	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	N/A
3. Less: Accumulated Depreciation	$23,133	$23,195	$23,257	$23,319	$23,381	$23,443	$23,505	$23,567	$23,629	$23,691	$23,753	$23,816	$23,878	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$7,897	$7,835	$7,773	$7,711	$7,649	$7,587	$7,525	$7,463	$7,401	$7,339	$7,277	$7,214	$7,152	N/A
6. Average Net Investment		$7,866	$7,804	$7,742	$7,680	$7,618	$7,556	$7,494	$7,432	$7,370	$7,308	$7,246	$7,183	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$50	$50	$49	$49	$48	$48	$48	$47	$47	$46	$46	$46	$573
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$11	$11	$11	$11	$11	$11	$11	$11	$11	$10	$10	$10	$129
8. Investment Expenses														
a. Depreciation [d]		$62	$62	$62	$62	$62	$62	$62	$62	$62	$62	$62	$62	$745
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$123	$123	$122	$122	$121	$121	$120	$120	$119	$119	$118	$118	$1,447

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
8b - Oil Spill Clean-up/Response Equipment														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($366,102)	$0	$19,500	$0	$64,500	$0	($9,275)	($28,144)	($8,505)	$0	($16,488)	$0	($344,514)
c. Retirements		$0	$0	$0	$0	$0	$0	($9,275)	($39,144)	($8,505)	$0	($44,988)	$0	($101,911)
d. Other		($5,506)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5,506)
2. Plant-In-Service/Depreciation Base [a]	$1,284,558	$918,456	$918,456	$937,956	$937,956	$1,002,456	$1,002,456	$993,181	$965,038	$956,533	$956,533	$940,044	$940,044	N/A
3. Less: Accumulated Depreciation	$243,229	$245,477	$253,231	$261,147	$269,226	$277,396	$285,581	$284,180	$252,719	$251,937	$259,392	$221,683	$229,030	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$1,041,329	$672,979	$665,225	$676,809	$668,730	$725,060	$716,875	$709,001	$712,319	$704,596	$697,141	$718,362	$711,014	N/A
6. Average Net Investment		$857,154	$669,102	$671,017	$672,769	$696,895	$720,967	$712,938	$710,660	$708,458	$700,868	$707,751	$714,688	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$5,438	$4,245	$4,257	$4,268	$4,421	$4,574	$4,523	$4,509	$4,495	$4,447	$4,490	$4,534	$54,201
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$1,224	$955	$958	$961	$995	$1,029	$1,018	$1,015	$1,012	$1,001	$1,011	$1,020	$12,198
8. Investment Expenses														
a. Depreciation [d]		$7,754	$7,754	$7,916	$8,079	$8,170	$8,184	$7,874	$7,682	$7,723	$7,455	$7,279	$7,347	$93,219
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$14,416	$12,954	$13,132	$13,308	$13,587	$13,788	$13,415	$13,205	$13,229	$12,903	$12,780	$12,902	$159,618

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
10 - Relocate Storm Water Runoff														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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. Plant-In-Service/Depreciation Base [a]	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	N/A
3. Less: Accumulated Depreciation	$55,346	$55,523	$55,700	$55,876	$56,053	$56,230	$56,406	$56,583	$56,760	$56,936	$57,113	$57,290	$57,466	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$62,448	$62,271	$62,094	$61,918	$61,741	$61,564	$61,388	$61,211	$61,034	$60,857	$60,681	$60,504	$60,327	N/A
6. Average Net Investment		$62,359	$62,183	$62,006	$61,829	$61,653	$61,476	$61,299	$61,122	$60,946	$60,769	$60,592	$60,416	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$396	$395	$393	$392	$391	$390	$389	$388	$387	$386	$384	$383	$4,674
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$89	$89	$89	$66	$88	$88	$88	$87	$87	$87	$87	$86	$1,052
8. Investment Expenses														
a. Depreciation [d]		$177	$177	$177	$177	$177	$177	$177	$177	$177	$177	$177	$177	$2,120
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$661	$660	$659	$657	$656	$654	$653	$652	$650	$649	$648	$646	$7,846

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
12 - Scherer Discharge Pipeline														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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. Plant-In-Service/Depreciation Base [a]	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	N/A
3. Less: Accumulated Depreciation	$490,864	$492,496	$494,128	$495,761	$497,393	$499,025	$500,658	$502,290	$503,922	$505,555	$507,187	$508,819	$510,452	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$363,460	$361,828	$360,195	$358,563	$356,931	$355,298	$353,666	$352,034	$350,401	$348,769	$347,137	$345,504	$343,872	N/A
6. Average Net Investment		$362,644	$361,011	$359,379	$357,747	$356,114	$354,482	$352,850	$351,217	$349,585	$347,953	$346,320	$344,688	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,301	$2,290	$2,280	$2,270	$2,259	$2,249	$2,239	$2,226	$2,218	$2,208	$2,197	$2,187	$26,925
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$518	$515	$513	$511	$508	$506	$504	$501	$499	$497	$494	$492	$6,060
8. Investment Expenses														
a. Depreciation [d]		$1,632	$1,632	$1,632	$1,632	$1,632	$1,632	$1,632	$1,632	$1,632	$1,632	$1,632	$1,632	$19,588
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$4,451	$4,438	$4,425	$4,413	$4,400	$4,387	$4,375	$4,362	$4,349	$4,337	$4,324	$4,311	$52,573

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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20 - Wastewater Discharge Elimination & Reuse														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($437,404)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($437,404)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		($153,617)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($153,617)
2. Plant-In-Service/Depreciation Base [a]	$1,235,070	$797,667	$797,667	$797,667	$797,667	$797,667	$797,667	$797,667	$797,667	$797,667	$797,667	$797,667	$797,667	N/A
3. Less: Accumulated Depreciation	$271,880	$119,991	$121,720	$123,448	$125,176	$126,904	$128,633	$130,361	$132,089	$133,817	$135,546	$137,274	$139,002	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$963,190	$677,675	$675,947	$674,219	$672,491	$670,762	$669,034	$667,306	$665,577	$663,849	$662,121	$660,393	$658,664	N/A
6. Average Net Investment		$820,433	$676,811	$675,083	$673,355	$671,626	$669,898	$668,170	$666,442	$664,713	$662,985	$661,257	$659,529	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$5,205	$4,294	$4,283	$4,272	$4,261	$4,250	$4,239	$4,228	$4,217	$4,206	$4,195	$4,184	$51,835
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$1,171	$966	$964	$961	$959	$956	$954	$952	$949	$947	$944	$942	$11,666
8. Investment Expenses														
a. Depreciation [d]		$1,728	$1,728	$1,728	$1,728	$1,728	$1,728	$1,728	$1,728	$1,728	$1,728	$1,728	$1,728	$20,739
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$8,105	$6,989	$6,975	$6,962	$6,948	$6,935	$6,921	$6,908	$6,895	$6,881	$6,868	$6,854	$84,240

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
21 - St. Lucie Turtle Nets														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,474,724	$3,474,724
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. Plant-In-Service/Depreciation Base [a]	$352,942	$352,942	$352,942	$352,942	$352,942	$352,942	$352,942	$352,942	$352,942	$352,942	$352,942	$352,942	$3,827,666	N/A
3. Less: Accumulated Depreciation	($700,592)	($700,063)	($699,533)	($699,004)	($698,474)	($697,945)	($697,416)	($696,886)	($696,357)	($695,827)	($695,298)	($694,769)	($691,633)	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$1,053,534	$1,053,005	$1,052,476	$1,051,946	$1,051,417	$1,050,887	$1,050,358	$1,049,829	$1,049,299	$1,048,770	$1,048,240	$1,047,711	$4,519,299	N/A
6. Average Net Investment		$1,053,270	$1,052,740	$1,052,211	$1,051,681	$1,051,152	$1,050,623	$1,050,093	$1,049,564	$1,049,034	$1,048,505	$1,047,976	$2,783,505	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$6,682	$6,679	$6,676	$6,672	$6,669	$6,665	$6,662	$6,659	$6,655	$6,652	$6,649	$17,659	$90,980
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$1,504	$1,503	$1,502	$1,502	$1,501	$1,500	$1,499	$1,499	$1,498	$1,497	$1,496	$3,974	$20,475
8. Investment Expenses														
a. Depreciation [d]		$529	$529	$529	$529	$529	$529	$529	$529	$529	$529	$529	$3,135	$8,959
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$8,716	$8,711	$8,707	$8,703	$8,699	$8,695	$8,691	$8,687	$8,683	$8,679	$8,674	$24,769	$120,414

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
22 - Pipeline Integrity Management														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$50,000	$0	$0	$0	$0	$0	$0	$0	$0	$50,000
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. Plant-In-Service/Depreciation Base [a]	$3,013,308	$3,013,308	$3,013,308	$3,013,308	$3,063,308	$3,063,308	$3,063,308	$3,063,308	$3,063,308	$3,063,308	$3,063,308	$3,063,308	$3,063,308	N/A
3. Less: Accumulated Depreciation	$26,380	$31,653	$36,926	$42,200	$47,517	$52,877	$58,238	$63,599	$68,960	$74,321	$79,681	$85,042	$90,403	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$2,986,929	$2,981,655	$2,976,382	$2,971,109	$3,015,792	$3,010,431	$3,005,070	$2,999,709	$2,994,349	$2,988,988	$2,983,627	$2,978,266	$2,972,905	N/A
6. Average Net Investment		$2,984,292	$2,979,019	$2,973,745	$2,993,450	$3,013,111	$3,007,751	$3,002,390	$2,997,029	$2,991,668	$2,986,307	$2,980,947	$2,975,586	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$18,933	$18,900	$18,866	$18,991	$19,116	$19,082	$19,048	$19,014	$18,980	$18,946	$18,912	$18,878	$227,668
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$4,261	$4,253	$4,246	$4,274	$4,302	$4,294	$4,287	$4,279	$4,272	$4,264	$4,256	$4,249	$51,237
8. Investment Expenses														
a. Depreciation [d]		$5,273	$5,273	$5,273	$5,317	$5,361	$5,361	$5,361	$5,361	$5,361	$5,361	$5,361	$5,361	$64,023
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$28,468	$28,427	$28,386	$28,583	$28,779	$28,737	$28,696	$28,654	$28,612	$28,571	$28,529	$28,487	$342,928

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($3,128,625)	$6,666	$6,666	$406,666	$6,666	$6,666	$6,666	$15,698	$6,666	$6,666	$6,666	$6,674	($2,646,259)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		($267,332)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($267,332)
2. Plant-In-Service/Depreciation Base [a]	$18,705,021	$15,576,395	$15,583,061	$15,589,727	$15,996,393	$16,003,059	$16,009,725	$16,016,391	$16,032,089	$16,038,755	$16,045,421	$16,052,087	$16,058,761	N/A
3. Less: Accumulated Depreciation	$3,605,332	$3,370,278	$3,402,567	$3,434,867	$3,467,761	$3,501,248	$3,534,746	$3,568,255	$3,601,782	$3,635,327	$3,668,882	$3,702,448	$3,736,024	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$15,099,689	$12,206,117	$12,180,494	$12,154,860	$12,528,633	$12,501,811	$12,474,979	$12,448,136	$12,430,308	$12,403,429	$12,376,539	$12,349,640	$12,322,737	N/A
6. Average Net Investment		$13,652,903	$12,193,306	$12,167,677	$12,341,746	$12,515,222	$12,488,395	$12,461,558	$12,439,222	$12,416,868	$12,389,984	$12,363,089	$12,336,188	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$86,618	$77,358	$77,196	$78,300	$79,401	$79,230	$79,060	$78,918	$78,777	$78,606	$78,435	$78,265	$950,165
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$19,494	$17,410	$17,373	$17,622	$17,869	$17,831	$17,793	$17,761	$17,729	$17,690	$17,652	$17,614	$213,836
8. Investment Expenses														
a. Depreciation [d]		$32,279	$32,289	$32,300	$32,894	$33,488	$33,498	$33,509	$33,527	$33,545	$33,555	$33,566	$33,576	$398,025
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$138,391	$127,057	$126,868	$128,815	$130,757	$130,559	$130,361	$130,206	$130,050	$129,852	$129,653	$129,455	$1,562,026

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
24 - Manatee Reburn														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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. Plant-In-Service/Depreciation Base [a]	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	$31,170,571	N/A
3. Less: Accumulated Depreciation	$5,884,479	$5,952,015	$6,019,551	$6,087,087	$6,154,624	$6,222,160	$6,289,696	$6,357,232	$6,424,769	$6,492,305	$6,559,841	$6,627,377	$6,694,914	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$25,286,092	$25,218,556	$25,151,020	$25,083,483	$25,015,947	$24,948,411	$24,880,875	$24,813,338	$24,745,802	$24,678,266	$24,610,730	$24,543,194	$24,475,657	N/A
6. Average Net Investment		$25,252,324	$25,184,788	$25,117,251	$25,049,715	$24,982,179	$24,914,643	$24,847,107	$24,779,570	$24,712,034	$24,644,498	$24,576,962	$24,509,425	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$160,209	$159,780	$159,352	$158,923	$158,495	$158,067	$157,638	$157,210	$156,781	$156,353	$155,924	$155,496	$1,894,227
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$36,055	$35,959	$35,862	$35,766	$35,670	$35,573	$35,477	$35,380	$35,284	$35,187	$35,091	$34,995	$426,299
8. Investment Expenses														
a. Depreciation [d]		$67,536	$67,536	$67,536	$67,536	$67,536	$67,536	$67,536	$67,536	$67,536	$67,536	$67,536	$67,536	$810,435
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$263,800	$263,275	$262,751	$262,226	$261,701	$261,176	$260,651	$260,126	$259,601	$259,076	$258,551	$258,026	$3,130,961

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

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25 - Pt. Everglades ESP Technology														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($81,901,169)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($81,901,169)
c. Retirements		($81,901,169)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($81,901,169)
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base [a]	$81,901,169	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
3. Less: Accumulated Depreciation	$17,895,361	($62,523,701)	($61,193,409)	($59,863,118)	($58,532,826)	($57,202,535)	($55,872,243)	($54,541,952)	($53,211,660)	($51,881,369)	($50,551,077)	($49,220,786)	($47,890,494)	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$64,005,809	$62,523,701	$61,193,409	$59,863,118	$58,532,826	$57,202,535	$55,872,243	$54,541,952	$53,211,660	$51,881,369	$50,551,077	$49,220,786	$47,890,494	N/A
6. Average Net Investment		$63,264,755	$61,858,555	$60,528,263	$59,197,972	$57,867,681	$56,537,389	$55,207,098	$53,876,806	$52,546,515	$51,216,223	$49,885,932	$48,555,640	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$401,372	$392,451	$384,011	$375,571	$367,131	$358,691	$350,252	$341,812	$333,372	$324,932	$316,492	$308,053	$4,254,140
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$90,329	$88,322	$86,422	$84,523	$82,623	$80,724	$78,825	$76,925	$75,026	$73,127	$71,227	$69,328	$957,401
8. Investment Expenses														
a. Depreciation [d]		$151,816	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$151,816
b. Amortization [e]		$1,330,291	$1,330,291	$1,330,292	$1,330,291	$1,330,292	$1,330,291	$1,330,292	$1,330,291	$1,330,292	$1,330,291	$1,330,292	$1,330,291	$15,963,498
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$1,973,809	$1,811,064	$1,800,725	$1,790,385	$1,780,046	$1,769,707	$1,759,368	$1,749,029	$1,738,689	$1,728,350	$1,718,011	$1,707,672	$21,326,855

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-36.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
26 - UST Remove/Replacement														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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. Plant-In-Service/Depreciation Base [a]	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	N/A
3. Less: Accumulated Depreciation	$23,263	$23,465	$23,667	$23,869	$24,071	$24,273	$24,475	$24,677	$24,879	$25,082	$25,284	$25,486	$25,688	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$92,183	$91,981	$91,779	$91,577	$91,375	$91,173	$90,971	$90,769	$90,567	$90,365	$90,163	$89,961	$89,759	N/A
6. Average Net Investment		$92,082	$91,880	$91,678	$91,476	$91,274	$91,072	$90,870	$90,668	$90,466	$90,264	$90,062	$89,860	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$584	$583	$582	$580	$579	$578	$577	$575	$574	$573	$571	$570	$6,926
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$131	$131	$131	$131	$130	$130	$130	$129	$129	$129	$129	$128	$1,559
8. Investment Expenses														
a. Depreciation [d]		$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$2,424
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$918	$916	$915	$913	$911	$910	$908	$907	$905	$904	$902	$900	$10,909

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$946,664	$874,045	$841,897	$884,237	$401,447	$253,331	$180,932	$204,617	$136,053	$222,001	$356,212	$5,301,436
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. Plant-In-Service/Depreciation Base [a]	$516,988,862	$516,988,862	$517,935,526	$518,809,571	$519,651,468	$520,535,705	$520,937,152	$521,190,483	$521,371,415	$521,576,032	$521,712,085	$521,934,086	$522,290,298	N/A
3. Less: Accumulated Depreciation	$17,029,418	$18,151,051	$19,273,710	$20,398,341	$21,524,832	$22,653,192	$23,782,945	$24,913,407	$26,044,340	$27,175,691	$28,307,410	$29,439,518	$30,572,251	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$499,959,444	$498,837,811	$498,661,816	$498,411,230	$498,126,637	$497,882,514	$497,154,208	$496,277,076	$495,327,075	$494,400,342	$493,404,675	$492,494,569	$491,718,047	N/A
6. Average Net Investment		$499,398,628	$498,749,814	$498,536,523	$498,268,933	$498,004,575	$497,518,361	$496,715,642	$495,802,076	$494,863,709	$493,902,509	$492,949,622	$492,106,308	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$3,168,346	$3,164,230	$3,162,876	$3,161,179	$3,159,502	$3,156,417	$3,151,324	$3,145,528	$3,139,575	$3,133,477	$3,127,431	$3,122,081	$37,791,965
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$713,041	$712,115	$711,810	$711,428	$711,051	$710,357	$709,211	$707,906	$706,566	$705,194	$703,833	$702,629	$8,505,143
8. Investment Expenses														
a. Depreciation [d]		$1,121,633	$1,122,659	$1,124,631	$1,126,490	$1,128,360	$1,129,753	$1,130,462	$1,130,933	$1,131,351	$1,131,720	$1,132,107	$1,132,734	$13,542,834
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$5,003,021	$4,999,003	$4,999,318	$4,999,097	$4,998,913	$4,996,527	$4,990,997	$4,984,367	$4,977,492	$4,970,390	$4,963,372	$4,957,444	$59,839,942

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
33 - MATS Project														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$149,728	$105,635	$84,526	$86,365	$78,524	$98,120	$67,450	$87,575	$68,950	$88,000	$72,142	$987,015
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. Plant-In-Service/Depreciation Base [a]	$107,121,508	$107,121,508	$107,271,236	$107,376,871	$107,461,397	$107,547,762	$107,626,286	$107,724,406	$107,791,856	$107,879,431	$107,948,381	$108,036,381	$108,108,523	N/A
3. Less: Accumulated Depreciation	$7,431,018	$7,663,073	$7,895,291	$8,127,786	$8,360,486	$8,593,372	$8,826,436	$9,059,692	$9,293,127	$9,526,730	$9,760,502	$9,994,445	$10,228,561	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$99,690,491	$99,458,435	$99,375,945	$99,249,086	$99,100,911	$98,954,391	$98,799,850	$98,664,715	$98,498,730	$98,352,702	$98,187,879	$98,041,937	$97,879,963	N/A
6. Average Net Investment		$99,574,463	$99,417,190	$99,312,515	$99,174,998	$99,027,651	$98,877,120	$98,732,282	$98,581,722	$98,425,716	$98,270,291	$98,114,908	$97,960,950	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$631,732	$630,735	$630,071	$629,198	$628,263	$627,308	$626,389	$625,434	$624,444	$623,458	$622,473	$621,496	$7,521,003
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$142,172	$141,948	$141,798	$141,602	$141,392	$141,177	$140,970	$140,755	$140,532	$140,310	$140,088	$139,869	$1,692,614
8. Investment Expenses														
a. Depreciation [d]		$232,056	$232,218	$232,494	$232,700	$232,886	$233,064	$233,256	$233,435	$233,603	$233,772	$233,943	$234,116	$2,797,543
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$1,005,961	$1,004,900	$1,004,363	$1,003,501	$1,002,541	$1,001,549	$1,000,615	$999,624	$998,580	$997,541	$996,504	$995,480	$12,011,159

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

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ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
34 - St Lucie Cooling Water System Inspection & Maintenance														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,873,359	$3,873,359
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. Plant-In-Service/Depreciation Base [a]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,873,359	N/A
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,905	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,870,454	N/A
6. Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,935,227	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,278	$12,278
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,763	$2,763
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,905	$2,905
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,946	$17,946

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
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35 - Martin Plant Drinking Water System Compliance														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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. Plant-In-Service/Depreciation Base [a]	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	N/A
3. Less: Accumulated Depreciation	$18,597	$19,009	$19,421	$19,833	$20,245	$20,657	$21,069	$21,481	$21,892	$22,304	$22,716	$23,128	$23,540	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$216,794	$216,383	$215,971	$215,559	$215,147	$214,735	$214,323	$213,911	$213,499	$213,087	$212,675	$212,263	$211,851	N/A
6. Average Net Investment		$216,588	$216,177	$215,765	$215,353	$214,941	$214,529	$214,117	$213,705	$213,293	$212,881	$212,469	$212,057	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,374	$1,371	$1,369	$1,366	$1,364	$1,361	$1,358	$1,356	$1,353	$1,351	$1,348	$1,345	$16,317
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$309	$309	$308	$307	$307	$306	$306	$305	$305	$304	$303	$303	$3,672
8. Investment Expenses														
a. Depreciation [d]		$412	$412	$412	$412	$412	$412	$412	$412	$412	$412	$412	$412	$4,943
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$2,095	$2,092	$2,089	$2,086	$2,082	$2,079	$2,076	$2,073	$2,070	$2,066	$2,063	$2,060	$24,932

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
36 - Low-Level Radioactive Waste Storage														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,517,223	$10,517,223
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. Plant-In-Service/Depreciation Base [a]	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$6,454,033	$16,971,256	N/A
3. Less: Accumulated Depreciation	$185,366	$195,048	$204,729	$214,410	$224,091	$233,772	$243,453	$253,134	$262,815	$272,496	$282,177	$291,858	$309,427	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$6,268,666	$6,258,985	$6,249,304	$6,239,623	$6,229,942	$6,220,261	$6,210,580	$6,200,899	$6,191,218	$6,181,537	$6,171,856	$6,162,175	$16,661,829	N/A
6. Average Net Investment		$6,263,826	$6,254,145	$6,244,464	$6,234,783	$6,225,102	$6,215,421	$6,205,740	$6,196,059	$6,186,378	$6,176,696	$6,167,015	$11,412,002	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$39,740	$39,678	$39,617	$39,555	$39,494	$39,433	$39,371	$39,310	$39,248	$39,187	$39,126	$72,401	$506,160
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$8,943	$8,930	$8,916	$8,902	$8,888	$8,874	$8,861	$8,847	$8,833	$8,819	$8,805	$16,294	$113,912
8. Investment Expenses														
a. Depreciation [d]		$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$17,569	$124,061
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$58,364	$58,289	$58,214	$58,139	$58,063	$57,988	$57,913	$57,838	$57,762	$57,687	$57,612	$106,264	$744,133

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 8.18% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
37 - DeSoto Next Generation Solar Energy Center														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$10,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000
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. Plant-In-Service/Depreciation Base [a]	$152,036,539	$152,036,539	$152,036,539	$152,046,539	$152,046,539	$152,046,539	$152,046,539	$152,046,539	$152,046,539	$152,046,539	$152,046,539	$152,046,539	$152,046,539	N/A
3. Less: Accumulated Depreciation	$16,053,165	$16,474,954	$16,896,743	$17,318,546	$17,740,363	$18,162,179	$18,583,995	$19,005,812	$19,427,628	$19,849,445	$20,271,261	$20,693,078	$21,114,894	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$135,983,373	$135,561,584	$135,139,795	$134,727,993	$134,306,176	$133,884,360	$133,462,543	$133,040,727	$132,618,910	$132,197,094	$131,775,277	$131,353,461	$130,931,644	N/A
6. Average Net Investment		$135,772,479	$135,350,690	$134,933,894	$134,517,084	$134,095,268	$133,873,451	$133,251,635	$132,829,818	$132,408,002	$131,986,185	$131,564,369	$131,142,552	N/A
a. Average ITC Balance		$39,244,329	$39,122,263	$39,000,197	$38,878,131	$38,756,065	$38,633,999	$38,511,933	$38,389,867	$38,267,801	$38,145,735	$38,023,669	$37,901,603	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$940,422	$937,501	$934,811	$931,720	$928,798	$925,878	$922,954	$920,032	$917,110	$914,188	$911,266	$908,344	$11,092,825
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$203,526	$202,893	$202,268	$201,643	$201,011	$200,378	$199,746	$199,114	$198,481	$197,849	$197,217	$196,584	$2,400,711
8. Investment Expenses														
a. Depreciation [d]		$415,730	$415,730	$415,744	$415,757	$415,758	$415,757	$415,758	$415,757	$415,758	$415,757	$415,758	$415,757	$4,989,021
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$6,059	$8,059	$6,059	$6,059	$6,059	$6,059	$6,059	$6,059	$6,059	$6,059	$6,059	$6,059	$72,708
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Expenses (Lines 7 & 8)		$1,405,342	$1,401,788	$1,398,287	$1,394,785	$1,391,231	$1,387,676	$1,384,122	$1,380,568	$1,377,013	$1,373,459	$1,369,905	$1,366,350	$16,630,525

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
38 - Space Coast Next Generation Solar Energy Center														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$3,728	$0	$0	$0	$0	$0	$0	$0	$3,728
c. Retirements		$0	$0	$0	$0	($7,272)	$0	$0	$0	$0	$0	$0	$0	($7,272)
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base [a]	$70,633,200	$70,633,200	$70,633,200	$70,633,200	$70,633,200	$70,636,928	$70,636,928	$70,636,928	$70,636,928	$70,636,928	$70,636,928	$70,636,928	$70,636,928	N/A
3. Less: Accumulated Depreciation	$6,422,815	$6,620,574	$6,818,334	$7,016,094	$7,213,752	$7,404,129	$7,601,867	$7,799,605	$7,997,343	$8,195,081	$8,392,819	$8,590,557	$8,788,295	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$64,210,385	$64,012,625	$63,814,866	$63,617,106	$63,419,447	$63,232,800	$63,035,062	$62,837,323	$62,639,585	$62,441,847	$62,244,109	$62,046,371	$61,848,633	N/A
6. Average Net Investment		$64,111,505	$63,913,746	$63,715,986	$63,518,277	$63,326,124	$63,133,931	$62,936,192	$62,738,454	$62,540,716	$62,342,978	$62,145,240	$61,947,502	N/A
a. Average ITC Balance		$16,738,671	$16,687,482	$16,636,293	$16,585,104	$16,533,915	$16,482,726	$16,431,537	$16,380,348	$16,329,159	$16,277,970	$16,226,781	$16,175,592	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$440,456	$439,098	$437,740	$436,383	$435,061	$433,738	$432,381	$431,023	$429,665	$428,308	$426,950	$425,593	$5,196,395
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$95,663	$95,368	$95,073	$94,778	$94,491	$94,204	$93,909	$93,614	$93,319	$93,024	$92,729	$92,434	$1,128,606
8. Investment Expenses														
a. Depreciation [d]		$194,848	$194,848	$194,848	$194,747	$194,736	$194,826	$194,826	$194,826	$194,826	$194,826	$194,826	$194,826	$2,337,808
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$2,912	$2,912	$2,912	$2,912	$2,912	$2,912	$2,912	$2,912	$2,912	$2,912	$2,912	$2,912	$34,944
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Expenses (Lines 7 & 8)		$666,615	$664,962	$663,310	$661,556	$659,937	$658,417	$656,765	$655,112	$653,460	$651,807	$650,154	$648,502	$7,890,598

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
39 - Martin Next Generation Solar Energy Center														
1. Investments														
a. Expenditures/Additions		$0	$0	$1,750,000	$1,975,500	$0	$0	$2,000,000	$2,225,500	$0	$0	$0	$0	$7,951,000
b. Clearings to Plant		$0	$0	$0	$3,500,000	$0	$0	$0	$4,451,000	$0	$0	$0	$0	$7,951,000
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. Plant-In-Service/Depreciation Base [a]	$411,631,319	$411,631,319	$411,631,319	$411,631,319	$415,131,319	$415,131,319	$415,131,319	$415,131,319	$419,582,319	$419,582,319	$419,582,319	$419,582,319	$419,582,319	N/A
3. Less: Accumulated Depreciation	$28,011,021	$29,174,822	$30,338,622	$31,502,422	$32,671,035	$33,844,461	$35,017,886	$36,191,312	$37,370,857	$38,556,523	$39,742,189	$40,927,854	$42,113,520	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$1,750,000	$225,500	$225,500	$225,500	$2,225,500	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$383,620,297	$382,456,497	$381,292,697	$381,878,896	$382,685,783	$381,512,358	$380,338,932	$381,165,507	$382,211,461	$381,025,796	$379,840,130	$378,654,464	$377,468,799	N/A
6. Average Net Investment		$383,038,397	$381,874,597	$381,585,796	$382,282,340	$382,099,070	$380,925,645	$380,752,220	$381,688,484	$381,618,629	$380,432,963	$379,247,297	$378,061,631	N/A
a. Average ITC Balance		$115,100,233	$114,756,435	$114,412,637	$114,068,839	$113,725,041	$113,381,243	$113,037,445	$112,693,647	$112,349,849	$112,006,051	$111,662,253	$111,318,455	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,661,931	$2,653,855	$2,651,330	$2,655,057	$2,653,202	$2,645,065	$2,643,272	$2,648,520	$2,647,384	$2,639,170	$2,630,955	$2,622,740	$31,752,482
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$575,263	$573,517	$573,019	$573,929	$573,583	$571,823	$571,490	$572,743	$572,558	$570,780	$569,003	$567,225	$6,864,934
8. Investment Expenses														
a. Depreciation [d]		$1,134,953	$1,134,953	$1,134,953	$1,139,766	$1,144,578	$1,144,578	$1,144,578	$1,150,699	$1,156,819	$1,156,819	$1,156,819	$1,156,819	$13,756,335
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$28,847	$28,847	$28,847	$28,647	$28,847	$28,847	$28,847	$28,847	$28,847	$28,847	$28,847	$28,847	$346,164
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Expenses (Lines 7 & 8)		$3,949,243	$3,939,421	$3,936,399	$3,945,848	$3,948,459	$3,938,562	$3,936,437	$3,949,057	$3,953,857	$3,943,865	$3,933,873	$3,923,880	$47,298,902

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
41 - Manatee Temporary Heating System														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$67,689	$32,189	$20,189	$16,189	$16,189	$21,689	$20,689	$11,689	$11,689	$19,313	$21,956	$10,000	$269,474
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. Plant-In-Service/Depreciation Base [a]	$11,871,104	$11,938,793	$11,970,983	$11,991,172	$12,007,362	$12,023,551	$12,045,240	$12,065,930	$12,077,619	$12,089,309	$12,108,622	$12,130,578	$12,140,578	N/A
3. Less: Accumulated Depreciation	$258,761	$273,554	$288,442	$303,381	$318,355	$333,360	$348,401	$363,483	$378,596	$393,731	$408,896	$424,100	$439,335	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$11,612,343	$11,665,240	$11,682,540	$11,687,791	$11,689,006	$11,690,191	$11,696,839	$11,702,447	$11,699,024	$11,695,578	$11,699,726	$11,706,477	$11,701,242	N/A
6. Average Net Investment		$11,638,792	$11,673,890	$11,685,166	$11,688,399	$11,689,599	$11,693,515	$11,699,643	$11,700,735	$11,697,301	$11,697,652	$11,703,102	$11,703,860	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$73,840	$74,063	$74,134	$74,155	$74,163	$74,187	$74,226	$74,233	$74,211	$74,214	$74,248	$74,253	$889,929
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$16,618	$16,668	$16,684	$16,689	$16,690	$16,696	$16,705	$16,706	$16,701	$16,702	$16,710	$16,711	$200,280
8. Investment Expenses														
a. Depreciation [d]		$14,793	$14,889	$14,939	$14,974	$15,005	$15,041	$15,082	$15,113	$15,135	$15,165	$15,204	$15,235	$180,575
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$105,251	$105,620	$105,757	$105,617	$105,858	$105,925	$106,013	$106,052	$106,048	$106,081	$106,162	$106,199	$1,270,783

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
42 - Turkey Point Cooling Canal Monitoring Plan														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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. Plant-In-Service/Depreciation Base [a]	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	$3,582,753	N/A
3. Less: Accumulated Depreciation	$132,082	$137,456	$142,830	$148,204	$153,578	$158,953	$164,327	$169,701	$175,075	$180,449	$185,823	$191,197	$196,571	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$3,450,671	$3,445,297	$3,439,923	$3,434,549	$3,429,174	$3,423,800	$3,418,426	$3,413,052	$3,407,678	$3,402,304	$3,396,930	$3,391,556	$3,386,181	N/A
6. Average Net Investment		$3,447,984	$3,442,610	$3,437,236	$3,431,862	$3,426,487	$3,421,113	$3,415,739	$3,410,365	$3,404,991	$3,399,617	$3,394,243	$3,388,868	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$21,875	$21,841	$21,807	$21,773	$21,739	$21,705	$21,671	$21,636	$21,602	$21,568	$21,534	$21,500	$260,251
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$4,923	$4,915	$4,908	$4,900	$4,892	$4,885	$4,877	$4,869	$4,862	$4,854	$4,846	$4,839	$58,570
8. Investment Expenses														
a. Depreciation [d]		$5,374	$5,374	$5,374	$5,374	$5,374	$5,374	$5,374	$5,374	$5,374	$5,374	$5,374	$5,374	$64,490
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$32,172	$32,131	$32,089	$32,047	$32,005	$31,963	$31,922	$31,880	$31,838	$31,796	$31,755	$31,713	$383,311

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
44 - Martin Plant Barley Barber Swamp Iron Mitigation														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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. Plant-In-Service/Depreciation Base [a]	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	N/A
3. Less: Accumulated Depreciation	$5,278	$5,567	$5,855	$6,143	$6,432	$6,720	$7,008	$7,296	$7,585	$7,873	$8,161	$8,449	$8,738	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$159,440	$159,152	$158,864	$158,575	$158,287	$157,999	$157,711	$157,422	$157,134	$156,846	$156,557	$156,269	$155,981	N/A
6. Average Net Investment		$159,296	$159,008	$158,719	$158,431	$158,143	$157,855	$157,566	$157,278	$156,990	$156,702	$156,413	$156,125	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,011	$1,009	$1,007	$1,005	$1,003	$1,001	$1,000	$998	$996	$994	$992	$991	$12,007
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$227	$227	$227	$226	$226	$225	$225	$225	$224	$224	$223	$223	$2,702
8. Investment Expenses														
a. Depreciation [d]		$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$3,459
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$1,526	$1,524	$1,522	$1,520	$1,517	$1,515	$1,513	$1,511	$1,508	$1,506	$1,504	$1,502	$18,168

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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45 - 800 MW Unit ESP														
1. Investments														
a. Expenditures/Additions		$5,550,578	$2,789,273	$2,093,272	$1,956,520	$2,105,057	$3,761,280	$7,696,477	$9,752,364	$10,226,443	$11,842,002	$3,065,724	$7,182,099	$68,021,089
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$40,979,605	$1,610,673	$7,385,294	$0	$0	$49,975,572
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. Plant-In-Service/Depreciation Base [a]	$61,517,629	$61,517,629	$61,517,629	$61,517,629	$61,517,629	$61,517,629	$61,517,629	$61,517,629	$102,497,234	$104,107,907	$111,493,201	$111,493,201	$111,493,201	N/A
3. Less: Accumulated Depreciation	$670,393	$803,681	$936,970	$1,070,258	$1,203,546	$1,336,834	$1,470,122	$1,603,411	$1,781,093	$2,004,916	$2,238,483	$2,480,052	$2,721,621	N/A
4. CWIP - Non Interest Bearing	$25,707,665	$31,258,243	$34,047,516	$36,140,788	$38,097,306	$40,202,365	$43,963,645	$51,660,122	$20,432,881	$29,046,651	$33,505,359	$36,571,083	$43,753,182	N/A
5. Net Investment (Lines 2 - 3 + 4)	$86,554,901	$91,972,191	$94,628,175	$96,588,159	$98,411,391	$100,383,160	$104,011,152	$111,574,340	$121,149,022	$131,151,643	$142,760,077	$145,584,232	$152,524,762	N/A
6. Average Net Investment		$89,263,546	$93,300,183	$95,608,167	$97,499,775	$99,397,275	$102,197,156	$107,792,746	$116,361,681	$126,150,332	$136,955,860	$144,172,154	$149,054,497	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$566,317	$591,926	$606,569	$618,570	$630,608	$646,372	$683,872	$736,236	$800,338	$868,892	$914,675	$945,650	$8,614,025
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$127,450	$133,214	$136,509	$139,210	$141,919	$145,917	$153,906	$166,141	$180,117	$195,546	$205,849	$212,820	$1,938,600
8. Investment Expenses														
a. Depreciation [d]		$133,288	$133,288	$133,286	$133,288	$133,288	$133,288	$133,288	$177,683	$223,822	$233,568	$241,569	$241,569	$2,051,227
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$827,055	$858,429	$876,367	$891,068	$905,816	$927,577	$971,067	$1,082,060	$1,204,278	$1,298,006	$1,362,092	$1,400,038	$12,603,853

[a] Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 34-38.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on May 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

[c] The Debt Component is 1.7134% based on May 2012 ROR Surveillance Report and reflects a 10% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

[d] Applicable depreciation rate or rates. See Form 42-4P, pages 34-38.

[e] Applicable amortization period(s). See Form 42-4P, pages 34-38.

[f] Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

[g] For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% based on the May 2012 ROR Surveillance Report and reflects a 10% return on equity.

Debt Component: Return of 2.01%based on the May 2012 ROR Surveillance Report and reflects a 10% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

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

FORM: 42-4P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1. Working Capital Dr(Cr)														
a. 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
b. 158.200 Allowances Withheld	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 182.300 Other Regulatory Assets-Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
d. 254.900 Other Regulatory Liabilities-Gains	($1,200,474)	($1,154,426)	($1,108,378)	($1,062,329)	($1,016,281)	($972,777)	($926,595)	($880,413)	($834,231)	($788,049)	($741,866)	($695,684)	($649,502)	
2. Total Working Capital	($1,200,474)	($1,154,426)	($1,108,378)	($1,062,329)	($1,016,281)	($972,777)	($926,595)	($880,413)	($834,231)	($788,049)	($741,866)	($695,684)	($649,502)	
3. Average Net Working Capital Balance		($1,177,450)	($1,131,402)	($1,085,353)	($1,039,305)	($994,529)	($949,686)	($903,504)	($857,322)	($811,140)	($764,957)	($718,775)	($672,593)	
4. Return on Average Net Working Capital Balance														
a. Equity Component grossed up for taxes [a]		($7,470)	($7,178)	($6,886)	($6,594)	($6,310)	($6,025)	($5,732)	($5,439)	($5,146)	($4,853)	($4,560)	($4,267)	
b. Debt Component (Line 6 x 1.6698% x 1/12)		($1,681)	($1,615)	($1,550)	($1,484)	($1,420)	($1,356)	($1,290)	($1,224)	($1,158)	($1,092)	($1,026)	($960)	
5. Total Return Component [d]		($9,151)	($8,793)	($8,435)	($8,078)	($7,730)	($7,381)	($7,022)	($6,663)	($6,304)	($5,945)	($5,586)	($5,227)	($86,317)
6. Expense Dr(Cr)														
a. 411.800 Gains from Dispositions of Allowances		($46,048)	($46,048)	($46,048)	($46,048)	($46,718)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	
b. 411.900 Losses from Dispositions of Allowances		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 509.000 Allowance Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Net Expense (Lines 6a + 6b + 6c) [e]		($46,048)	($46,048)	($46,048)	($46,048)	($46,718)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	($46,182)	($554,186)
8. Total System Recoverable Expenses (Lines 5 + 7)		($55,200)	($54,842)	($54,484)	($54,126)	($54,447)	($53,563)	($53,204)	($52,845)	($52,486)	($52,128)	($51,769)	($51,410)	
a. Recoverable Costs Allocated to Energy		($55,200)	($54,842)	($54,484)	($54,126)	($54,447)	($53,563)	($53,204)	($52,845)	($52,486)	($52,128)	($51,769)	($51,410)	
b. Recoverable Costs Allocated to Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
9. Energy Jurisdictional Factor		98.03238%	98.03238%	98.03236%	98.03238%	98.03238%	98.03236%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	
10. Demand Jurisdictional Factor		97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	
11. Retail Energy-Related Recoverable Costs [b]		($54,113)	($53,763)	($53,412)	($53,061)	($53,376)	($52,509)	($52,157)	($51,806)	($51,454)	($51,102)	($50,750)	($50,398)	
12. Retail Demand-Related Recoverable Costs [c]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
13. Total Jurisdictional Recoverable Costs (Lines 11 + 12)		($54,113)	($53,763)	($53,412)	($53,061)	($53,376)	($52,509)	($52,157)	($51,806)	($51,454)	($51,102)	($50,750)	($50,398)	($627,901)

[a] March 2010 forward, the Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.6764% is based on 2012 ROR Surveillance Report and reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

[b] Line 8a times Line 9

[c] Line 8b times Line 10

[d] Line 5 is reported on Capital Schedule

[e] Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
ANNUAL CAPITAL DEPRECIATION SCHEDULE
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

FORM: 42-4P

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Dec - 2012	Dec - 2013
2 - Low NOX Burner Technology	02 - Steam Generation Plant	PtEvergiades U1	31200	0.00%	$2,689,233	$0
2 - Low NOX Burner Technology	02 - Steam Generation Plant	PtEvergiades U2	31200	0.00%	$2,368,972	$0
2 - Low NOX Burner Technology	02 - Steam Generation Plant	TurkeyPt U1	31200	2.50%	$2,563,376	$2,563,376
2 - Low NOX Burner Technology	02 - Steam Generation Plant	TurkeyPt U2	31200	2.50%	$2,275,222	$2,275,222
2 - Low NOX Burner Technology					**$9,896,803**	**$4,838,598**
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	$31,859	$65,859
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Manatee U1	31100	2.10%	$56,430	$56,430
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Manatee U1	31200	2.60%	$505,974	$505,974
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Manatee U2	31100	2.10%	$56,333	$56,333
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Manatee U2	31200	2.60%	$508,552	$508,552
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Martin Comm	31200	2.60%	$31,632	$52,632
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Martin U1	31100	2.10%	$36,811	$36,611
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Martin U1	31200	2.60%	$542,175	$542,175
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Martin U2	31100	2.10%	$36,845	$36,845
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Martin U2	31200	2.60%	$529,518	$529,518
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	PtEverglades Comm	31100	0.00%	$127,911	$0
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	PtEverglades Comm	31200	0.00%	$67,788	$0
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	PtEverglades U1	31200	0.00%	$458,061	$0
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	PtEverglades U2	31200	0.00%	$480,322	$0
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	PtEverglades U3	31200	0.00%	$507,658	$0
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	PtEverglades U4	31200	0.00%	$517,303	$0
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	Scherer U4	31200	2.60%	$515,653	$515,653
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	$43,193	$43,193
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	$780	$780
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	$780	$780
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	$59,056	$59,056
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31200	2.50%	$37,955	$101,455
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	TurkeyPt U1	31200	2.50%	$545,584	$545,584
3b - Continuous Emission Monitoring Systems	02 - Steam Generation Plant	TurkeyPt U2	31200	2.50%	$504,689	$504,689
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	$58,860	$56,860
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	FtLauderdale Comm	34500	3.40%	$34,502	$34,502
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	FtLauderdale U4	34300	4.30%	$462,254	$508,754
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	FtLauderdale U5	34300	4.20%	$473,360	$519,860
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	$0	$18,000
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	FtMyers U2 CC	34300	4.20%	$171,024	$225,024
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	FtMyers U3 CC	34300	5.20%	$2,283	$51,283
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Martin U3	34300	4.20%	$444,950	$457,950
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Martin U4	34300	4.20%	$437,552	$450,552
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Martin U8	34300	4.30%	$13,693	$13,693
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	PtEverglades GTs	34300	3.40%	$0	$34,000
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Putnam Comm	34100	2.60%	$82,858	$82,858
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Putnam Comm	34300	4.20%	$3,139	$3,139
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Putnam U1	34300	4.00%	$346,616	$393,116
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Putnam U2	34300	3.30%	$380,355	$426,855
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Sanford U4	34300	4.80%	$147,961	$183,961
3b - Continuous Emission Monitoring Systems	05 - Other Generation Plant	Sanford U5	34300	4.20%	$106,139	$142,139
3b - Continuous Emission Monitoring Systems					**$9,368,408**	**$7,766,864**
4b - Clean Closure Equivalency	02 - Steam Generation Plant	PtEverglades Comm	31100	0.00%	$19,812	$0
4b - Clean Closure Equivalency	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	$21,799	$21,799
4b - Clean Closure Equivalency					**$41,612**	**$21,799**
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	$3,111,263	$3,111,263
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	$174,543	$174,543
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	Manatee U1	31200	2.60%	$104,645	$104,845
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	Manatee U2	31200	2.60%	$127,429	$127,429
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	Martin Comm	31100	2.10%	$1,110,450	$1,110,450
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	Martin Comm	31200	2.60%	$94,329	$94,329
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	Martin U1	31100	2.10%	$176,339	$176,339
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	PtEverglades Comm	31100	0.00%	$1,132,078	$0
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	$42,091	$42,091
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	SJRPP - Comm	31200	2.60%	$2,292	$2,292
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	$87,560	$87,560
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	02 - Steam Generation Plant	TurkeyPt U2	31100	2.10%	$42,159	$42,159

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
ANNUAL CAPITAL DEPRECIATION SCHEDULE
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

FORM: 42-4P

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Dec - 2012	Dec - 2013
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	$898,111	$898,111
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	$584,290	$584,290
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	$133,479	$133,479
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	$2,781,640	$2,781,640
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	05 - Other Generation Plant	Putnam Comm	34200	2.90%	$749,026	$749,026
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks					**$11,351,926**	**$10,219,848**
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	$31,030	$31,030
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground					**$31,030**	**$31,030**
8b - Oil Spill Clean-up/Response Equipment	02 - Steam Generation Plant	Amortizable	31650	5-Year	$143,516	$181,516
8b - Oil Spill Clean-up/Response Equipment	02 - Steam Generation Plant	Amortizable	31670	7-Year	$314,015	$227,112
8b - Oil Spill Clean-up/Response Equipment	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	$46,882	$46,882
8b - Oil Spill Clean-up/Response Equipment	02 - Steam Generation Plant	Martin Comm	31600	2.40%	$23,107	$23,107
8b - Oil Spill Clean-up/Response Equipment	02 - Steam Generation Plant	PtEverglades Comm	31100	0.00%	$366,102	$0
8b - Oil Spill Clean-up/Response Equipment	05 - Other Generation Plant	Amortizable	34650	5-Year	$22,458	$13,184
8b - Oil Spill Clean-up/Response Equipment	05 - Other Generation Plant	Amortizable	34670	7-Year	$5,734	$0
8b - Oil Spill Clean-up/Response Equipment	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	$358,330	$358,330
8b - Oil Spill Clean-up/Response Equipment	05 - Other Generation Plant	FtLauderdale U5	34600	3.40%	$0	$64,500
8b - Oil Spill Clean-up/Response Equipment	05 - Other Generation Plant	West County Energy Center Comm	34600	3.30%	$0	$21,000
8b - Oil Spill Clean-up/Response Equipment	08 - General Plant	Other	39000	2.10%	$4,413	$4,413
8b - Oil Spill Clean-up/Response Equipment					**$1,284,558**	**$940,044**
10 - Relocate Storm Water Runoff	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	$117,794	$117,794
10 - Relocate Storm Water Runoff					**$117,794**	**$117,794**
12 - Scherer Discharge Pipeline	02 - Steam Generation Plant	Scherer Comm	31100	2.10%	$524,873	$524,873
12 - Scherer Discharge Pipeline	02 - Steam Generation Plant	Scherer Comm	31200	2.60%	$328,762	$328,762
12 - Scherer Discharge Pipeline	02 - Steam Generation Plant	Scherer Comm	31400	2.60%	$689	$689
12 - Scherer Discharge Pipeline					**$854,324**	**$854,324**
20 - Wastewater Discharge Elimination & Reuse	02 - Steam Generation Plant	Martin U1	31200	2.60%	$380,995	$380,995
20 - Wastewater Discharge Elimination & Reuse	02 - Steam Generation Plant	Martin U2	31200	2.60%	$416,672	$416,672
20 - Wastewater Discharge Elimination & Reuse	02 - Steam Generation Plant	PtEverglades Comm	31100	0.00%	$437,404	$0
20 - Wastewater Discharge Elimination & Reuse					**$1,235,070**	**$797,667**
21 - St. Lucie Turtle Nets	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	$352,942	$3,827,666
21 - St. Lucie Turtle Nets					**$352,942**	**$3,827,666**
22 - Pipeline Integrity Management	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	$752,070	$802,070
22 - Pipeline Integrity Management	02 - Steam Generation Plant	Martin Comm	31100	2.10%	$2,261,238	$2,261,238
22 - Pipeline Integrity Management					**$3,013,308**	**$3,063,308**
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	$807,719	$807,719
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	$33,272	$33,272
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	Manatee Comm	31500	2.40%	$26,325	$26,325
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	Manatee U1	31200	2.60%	$45,750	$45,750
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	Manatee U2	31200	2.60%	$37,431	$37,431
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	Martin Comm	31100	2.10%	$343,785	$343,785
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	Martin Comm	31500	2.40%	$34,755	$34,755
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	PtEverglades Comm	31100	0.00%	$2,967,754	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	PtEverglades Comm	31200	0.00%	$159,754	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	PtEverglades Comm	31500	0.00%	$7,783	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	$92,013	$92,013
23 - SPCC - Spill Prevention, Control & Countermeasures	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31500	2.20%	$13,559	$13,559
23 - SPCC - Spill Prevention, Control & Countermeasures	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	$1,019,614	$1,019,614
23 - SPCC - Spill Prevention, Control & Countermeasures	03 - Nuclear Generation Plant	StLucie U1	32400	1.80%	$437,945	$437,945
23 - SPCC - Spill Prevention, Control & Countermeasures	03 - Nuclear Generation Plant	StLucie U2	32300	2.40%	$552,390	$552,390
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	$189,219	$189,219
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	$1,480,169	$1,480,169
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtLauderdale Comm	34300	6.00%	$28,250	$28,250
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	$92,727	$92,727
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	$513,250	$513,250
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtMyers GTs	34100	2.30%	$178,936	$178,936
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	$629,983	$629,983

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
ANNUAL CAPITAL DEPRECIATION SCHEDULE
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

FORM: 42-4P

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Dec - 2012	Dec - 2013
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtMyers GTs	34500	2.20%	$12,430	$12,430
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtMyers U2 CC	34300	4.20%	$49,727	$49,727
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	FtMyers U3 CC	34500	3.40%	$12,430	$12,430
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	Martin Comm	34100	3.50%	$61,216	$461,216
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	Martin U8	34200	3.80%	$84,868	$84,868
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	PtEverglades GTs	34100	2.20%	$454,081	$454,081
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	$1,835,190	$1,835,190
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	PtEverglades GTs	34500	2.10%	$7,783	$7,783
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	Putnam Comm	34100	2.60%	$148,511	$148,511
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	Putnam Comm	34200	2.90%	$1,730,935	$1,730,935
23 - SPCC - Spill Prevention, Control & Countermeasures	05 - Other Generation Plant	Putnam Comm	34500	2.50%	$60,747	$60,747
23 - SPCC - Spill Prevention, Control & Countermeasures	06 - Transmission Plant - Electric	Other	35200	1.90%	$1,058,508	$1,074,506
23 - SPCC - Spill Prevention, Control & Countermeasures	06 - Transmission Plant - Electric	Other	35300	2.60%	$177,982	$177,982
23 - SPCC - Spill Prevention, Control & Countermeasures	06 - Transmission Plant - Electric	Other	35800	1.80%	$65,655	$65,655
23 - SPCC - Spill Prevention, Control & Countermeasures	07 - Distribution Plant - Electric	Other	36100	1.90%	$3,026,351	$3,090,353
23 - SPCC - Spill Prevention, Control & Countermeasures	07 - Distribution Plant - Electric	Other	36670	2.00%	$79,531	$88,563
23 - SPCC - Spill Prevention, Control & Countermeasures	08 - General Plant	Other	39000	2.10%	$146,691	$146,691
23 - SPCC - Spill Prevention, Control & Countermeasures					**$16,705,021**	**$16,058,761**
24 - Manatee Rebum	02 - Steam Generation Plant	Manatee U1	31200	2.60%	$16,687,067	$16,687,067
24 - Manatee Rebum	02 - Steam Generation Plant	Manatee U2	31200	2.60%	$14,483,504	$14,483,504
24 - Manatee Rebum					**$31,170,571**	**$31,170,571**
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U1	31100	4-Year	$298,710	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U1	31200	4-Year	$10,404,603	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U1	31500	4-Year	$2,500,249	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U1	31600	4-Year	$307,032	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U2	31100	4-Year	$184,084	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U2	31200	4-Year	$11,979,735	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U2	31500	4-Year	$3,954,582	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U2	31600	4-Year	$324,087	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U3	31100	4-Year	$713,693	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U3	31200	4-Year	$18,160,534	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U3	31500	4-Year	$4,304,057	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U3	31600	4-Year	$528,541	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U4	31100	4-Year	$313,276	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U4	31200	4-Year	$20,646,501	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U4	31500	4-Year	$6,729,950	$0
25 - Pt. Everglades ESP Technology	02 - Steam Generation Plant	PtEverglades U4	31600	4-Year	$551,535	$0
25 - Pt. Everglades ESP Technology					**$81,901,169**	**$0**
26 - UST Remove/Replacement	08 - General Plant	Other	39000	2.10%	$115,447	$115,447
26 - UST Remove/Replacement					**$115,447**	**$115,447**
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	$102,052	$102,052
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Manatee U1	31200	2.60%	$20,059,060	$20,059,060
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Manatee U1	31400	2.60%	$7,240,728	$7,240,728
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Manatee U2	31200	2.60%	$20,461,498	$20,461,498
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Manatee U2	31400	2.60%	$7,912,962	$7,912,962
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Martin Comm	31200	2.60%	$518,275	$518,275
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Martin Comm	31400	2.60%	$287,258	$287,258
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Martin U1	31200	2.60%	$19,504,077	$19,504,077
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Martin U1	31400	2.60%	$7,794,707	$7,794,707
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Martin U2	31200	2.60%	$20,248,975	$20,248,975
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Martin U2	31400	2.60%	$7,477,120	$7,477,120
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	Scherer U4	31200	2.60%	$348,261,192	$353,562,628
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	$27,708,299	$27,708,299
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	SJRPP U1	31500	2.40%	$455,146	$455,146
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	SJRPP U1	31600	2.40%	$9,138	$9,138
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	$26,524,626	$26,524,626
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	SJRPP U2	31500	2.40%	$426,220	$426,220
31 - Clean Air Interstate Rule (CAIR) Compliance	02 - Steam Generation Plant	SJRPP U2	31600	2.40%	$9,591	$9,591
31 - Clean Air Interstate Rule (CAIR) Compliance	05 - Other Generation Plant	FtLauderdale GTs	34300	2.90%	$110,242	$110,242
31 - Clean Air Interstate Rule (CAIR) Compliance	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	$57,855	$57,855
31 - Clean Air Interstate Rule (CAIR) Compliance	05 - Other Generation Plant	Martin Comm U3&4	34100	3.50%	$763,350	$763,350

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31 - Clean Air Interstate Rule (CAIR) Compliance	05 - Other Generation Plant	Martin Comm U3&4	34300	4.30%	$244,343	$244,343
31 - Clean Air Interstate Rule (CAIR) Compliance	05 - Other Generation Plant	Martin Comm U3&4	34500	3.40%	$292,499	$292,499
31 - Clean Air Interstate Rule (CAIR) Compliance	05 - Other Generation Plant	PtEverglades GTs	34300	3.40%	$107,874	$107,874
31 - Clean Air Interstate Rule (CAIR) Compliance	07 - Distribution Plant - Electric	Other	36500	3.90%	$411,775	$411,775
31 - Clean Air Interstate Rule (CAIR) Compliance					**$518,986,882**	**$522,290,298**
33 - MATS Project	02 - Steam Generation Plant	Scherer U4	31100	2.10%	$81,956	$81,956
33 - MATS Project	02 - Steam Generation Plant	Scherer U4	31200	2.60%	$106,998,574	$107,985,589
33 - MATS Project	02 - Steam Generation Plant	Scherer U4	31500	2.40%	$40,978	$40,978
33 - MATS Project					**$107,121,508**	**$108,108,523**
34 - St Lucie Cooling Water System Inspection & Maintenance	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	$0	$3,873,359
34 - St Lucie Cooling Water System Inspection & Maintenance					**$0**	**$3,873,359**
35 - Martin Plant Drinking Water System Compliance	02 - Steam Generation Plant	Martin Comm	31100	2.10%	$235,391	$235,391
35 - Martin Plant Drinking Water System Compliance					**$235,391**	**$235,391**
36 - Low-Level Radioactive Waste Storage	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	$6,454,033	$8,137,033
36 - Low-Level Radioactive Waste Storage	03 - Nuclear Generation Plant	TurkeyPt Comm	32100	1.80%	$0	$8,834,223
36 - Low-Level Radioactive Waste Storage					**$6,454,033**	**$16,971,256**
37 - DeSoto Next Generation Solar Energy Center	05 - Other Generation Plant	Amortizable	34650	5-Year	$21,935	$21,935
37 - DeSoto Next Generation Solar Energy Center	05 - Other Generation Plant	Amortizable	34670	7-Year	$59,592	$59,592
37 - DeSoto Next Generation Solar Energy Center	05 - Other Generation Plant	DeSoto Solar	34000	0.00%	$255,507	$255,507
37 - DeSoto Next Generation Solar Energy Center	05 - Other Generation Plant	DeSoto Solar	34100	3.30%	$4,502,770	$4,502,770
37 - DeSoto Next Generation Solar Energy Center	05 - Other Generation Plant	DeSoto Solar	34300	3.30%	$115,303,900	$115,303,900
37 - DeSoto Next Generation Solar Energy Center	05 - Other Generation Plant	DeSoto Solar	34500	3.30%	$26,194,769	$26,204,769
37 - DeSoto Next Generation Solar Energy Center	06 - Transmission Plant - Electric	Other	35200	1.90%	$5,655	$5,655
37 - DeSoto Next Generation Solar Energy Center	06 - Transmission Plant - Electric	Other	35300	2.60%	$520,413	$520,413
37 - DeSoto Next Generation Solar Energy Center	06 - Transmission Plant - Electric	Other	35310	2.90%	$1,712,305	$1,712,305
37 - DeSoto Next Generation Solar Energy Center	06 - Transmission Plant - Electric	Other	35500	3.40%	$394,418	$394,418
37 - DeSoto Next Generation Solar Energy Center	06 - Transmission Plant - Electric	Other	35600	3.20%	$191,358	$191,358
37 - DeSoto Next Generation Solar Energy Center	07 - Distribution Plant - Electric	Other	36100	1.90%	$608,255	$608,255
37 - DeSoto Next Generation Solar Energy Center	07 - Distribution Plant - Electric	Other	36200	2.60%	$2,215,123	$2,215,123
37 - DeSoto Next Generation Solar Energy Center	08 - General Plant	Amortizable	39720	7-Year	$22,114	$22,114
37 - DeSoto Next Generation Solar Energy Center	08 - General Plant	Other	39220	9.40%	$28,426	$28,426
37 - DeSoto Next Generation Solar Energy Center					**$152,036,539**	**$152,046,539**
38 - Space Coast Next Generation Solar Energy Center	01 - Intangible Plant	Amortizable	30300	30-Year	$6,359,027	$6,359,027
38 - Space Coast Next Generation Solar Energy Center	05 - Other Generation Plant	Amortizable	34630	3-Year	$7,272	$6,000
38 - Space Coast Next Generation Solar Energy Center	05 - Other Generation Plant	Amortizable	34650	5-Year	$9,438	$9,438
38 - Space Coast Next Generation Solar Energy Center	05 - Other Generation Plant	Amortizable	34670	7-Year	$51,560	$51,560
38 - Space Coast Next Generation Solar Energy Center	05 - Other Generation Plant	Spacecoast Solar	34100	3.30%	$3,838,726	$3,838,726
38 - Space Coast Next Generation Solar Energy Center	05 - Other Generation Plant	Spacecoast Solar	34300	3.30%	$51,606,083	$51,606,083
38 - Space Coast Next Generation Solar Energy Center	05 - Other Generation Plant	Spacecoast Solar	34500	3.30%	$6,126,699	$6,126,699
38 - Space Coast Next Generation Solar Energy Center	05 - Other Generation Plant	Spacecoast Solar	34600	3.30%	$0	$5,000
38 - Space Coast Next Generation Solar Energy Center	06 - Transmission Plant - Electric	Other	35300	2.60%	$139,391	$139,391
38 - Space Coast Next Generation Solar Energy Center	07 - Distribution Plant - Electric	Other	36100	1.90%	$269,799	$269,799
38 - Space Coast Next Generation Solar Energy Center	07 - Distribution Plant - Electric	Other	36200	2.60%	$2,186,996	$2,186,996
38 - Space Coast Next Generation Solar Energy Center	08 - General Plant	Amortizable	39720	7-Year	$6,351	$6,351
38 - Space Coast Next Generation Solar Energy Center	08 - General Plant	Other	39220	9.40%	$31,858	$31,858
38 - Space Coast Next Generation Solar Energy Center					**$70,633,200**	**$70,636,928**
39 - Martin Next Generation Solar Energy Center	05 - Other Generation Plant	Amortizable	34650	5-Year	$21,384	$21,384
39 - Martin Next Generation Solar Energy Center	05 - Other Generation Plant	Amortizable	34670	7-Year	$4,910	$4,910
39 - Martin Next Generation Solar Energy Center	05 - Other Generation Plant	Martin Solar	34000	0.00%	$216,844	$216,844
39 - Martin Next Generation Solar Energy Center	05 - Other Generation Plant	Martin Solar	34100	3.30%	$19,859,164	$19,859,164
39 - Martin Next Generation Solar Energy Center	05 - Other Generation Plant	Martin Solar	34300	3.30%	$385,420,310	$393,371,310
39 - Martin Next Generation Solar Energy Center	05 - Other Generation Plant	Martin Solar	34500	3.30%	$4,059,061	$4,059,061
39 - Martin Next Generation Solar Energy Center	05 - Other Generation Plant	Martin Solar	34600	3.30%	$1,299	$1,299
39 - Martin Next Generation Solar Energy Center	05 - Other Generation Plant	Martin U8	34300	4.30%	$423,126	$423,126
39 - Martin Next Generation Solar Energy Center	06 - Transmission Plant - Electric	Other	35500	3.40%	$603,692	$603,692
39 - Martin Next Generation Solar Energy Center	06 - Transmission Plant - Electric	Other	35600	3.20%	$364,159	$364,159
39 - Martin Next Generation Solar Energy Center	07 - Distribution Plant - Electric	Other	36400	4.10%	$9,282	$9,282
39 - Martin Next Generation Solar Energy Center	07 - Distribution Plant - Electric	Other	36680	1.50%	$94,476	$94,476

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39 - Martin Next Generation Solar Energy Center	07 - Distribution Plant - Electric	Other	36760	2.60%	$2,728	$2,728
39 - Martin Next Generation Solar Energy Center	08 - General Plant	Amortizable	39420	7-Year	$18,993	$18,993
39 - Martin Next Generation Solar Energy Center	08 - General Plant	Amortizable	39720	7-Year	$3,204	$3,204
39 - Martin Next Generation Solar Energy Center	08 - General Plant	Other	39220	9.40%	$25,193	$25,193
39 - Martin Next Generation Solar Energy Center	08 - General Plant	Other	39240	11.10%	$405,859	$405,859
39 - Martin Next Generation Solar Energy Center	08 - General Plant	Other	39290	3.50%	$97,633	$97,633
39 - Martin Next Generation Solar Energy Center					**$411,631,319**	**$419,582,319**
41 - Manatee Temporary Heating System	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	$4,042,459	$4,042,459
41 - Manatee Temporary Heating System	02 - Steam Generation Plant	PtEverglades Comm	31400	2.30%	$3,481,414	$3,750,888
41 - Manatee Temporary Heating System	02 - Steam Generation Plant	Riviera Comm	31400	0.60%	$2,605,268	$2,605,268
41 - Manatee Temporary Heating System	06 - Transmission Plant - Electric	Other	35300	2.60%	$276,404	$276,404
41 - Manatee Temporary Heating System	07 - Distribution Plant - Electric	Other	36100	1.90%	$29,981	$29,981
41 - Manatee Temporary Heating System	07 - Distribution Plant - Electric	Other	36200	2.60%	$488,124	$488,124
41 - Manatee Temporary Heating System	07 - Distribution Plant - Electric	Other	36400	4.10%	$226,155	$226,155
41 - Manatee Temporary Heating System	07 - Distribution Plant - Electric	Other	36500	3.90%	$307,184	$307,184
41 - Manatee Temporary Heating System	07 - Distribution Plant - Electric	Other	36660	1.50%	$221,326	$221,326
41 - Manatee Temporary Heating System	07 - Distribution Plant - Electric	Other	36760	2.60%	$168,995	$168,995
41 - Manatee Temporary Heating System	07 - Distribution Plant - Electric	Other	36910	3.90%	$607	$607
41 - Manatee Temporary Heating System	08 - General Plant	Amortizable	39720	7-Year	$23,187	$23,187
41 - Manatee Temporary Heating System					**$11,871,104**	**$12,140,578**
42 - Turkey Point Cooling Canal Monitoring Plan	03 - Nuclear Generation Plant	TurkeyPt Comm	32100	1.80%	$3,582,753	$3,582,753
42 - Turkey Point Cooling Canal Monitoring Plan					**$3,582,753**	**$3,582,753**
44 - Martin Plant Barley Barber Swamp Iron Mitigation	02 - Steam Generation Plant	Martin Comm	31100	2.10%	$164,719	$164,719
44 - Martin Plant Barley Barber Swamp Iron Mitigation					**$164,719**	**$164,719**
45 - 800 MW Unit ESP	02 - Steam Generation Plant	Manatee U1	31200	2.60%	$0	$49,975,572
45 - 800 MW Unit ESP	02 - Steam Generation Plant	Manatee U2	31200	2.60%	$61,517,629	$61,517,629
45 - 800 MW Unit ESP					**$61,517,629**	**$111,493,201**
				Total	$1,511,677,040	$1,500,949,586

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Air Operating Permit Fees - O & M**
Project No. 1

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, and Florida Statutes 403.0872, require each major source of air pollution to pay an annual license fee. The amount of the fee is based on each source's previous year's emissions. It is calculated by multiplying the applicable annual operation license fee factor by the tons of each air pollutant emitted by the unit during the previous year and regulated in each unit's air operating permit, up to a total of 4,000 tons per pollutant. The major regulated pollutants at the present time are sulfur dioxide (SO2), nitrogen oxides (NOx) and particulate matter. The fee covers units in FPL's service area, as well as Unit 4 of Plant Scherer located in Juliette, Georgia, within the Georgia Power Company service area. FPL's share of ownership of that unit is 76.36%. The fees for FPL's units are paid to the Florida Department of Environmental Protection (FDEP) generally in February of each year, whereas FPL pays its share of the fees for Scherer Unit 4 to Georgia Power Company on a monthly basis.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The monthly fees for 2011 emissions have been paid and continue to be paid in 2012. Year 2011 air operating permit fees for the Florida facilities were calculated in January 2012 utilizing 2011 operating information. They were paid to the FDEP in February, 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $783,832 or 60.8% lower than previously projected. Lower than projected natural gas prices resulted in significantly less oil-fired operation than estimated for the oil-burning units. Air Permit fees and payments to the State of Florida are based on actual unit operations and performance.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The monthly fees for 2011 emissions have been paid and continue to be paid in 2012. Year 2011 air operating permit fees for the Florida facilities were calculated in January 2012 utilizing 2011 operating information. They were paid to the FDEP in February, 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $289,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Continuous Emission Monitoring Systems (CEMS) - O & M**
Project No. 3a

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO2, NOx, CO, Carbon Dioxide (CO2/O2) emissions, as well as opacity data from affected air pollution sources. FPL has 57 units, which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants and opacity. These Systems continuously extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability. Operation and maintenance of these systems in accordance with the provisions of 40 CFR Part 75 is an ongoing activity, which follow the Title IV CEMS Quality Assurance Program Manual.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Operation and maintenance of the CEMS continue to be performed according to requirements of the Title IV CEM Quality Assurance Program Manual, 40 CFR Parts 60 & 75 regulations and all applicable FAC, as well as local requirements. Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled for quality assurance and as needed for diagnostic or recertification requirements. QA/QC maintenance continues to be performed on the analyzers to meet reliability and availability requirements. CEMS required parts continue to be purchased as needed for repairs and/or preventative maintenance. Equipment having met end of life has been replaced as recommended by OEMs. Calibration span gases continue to be purchased as needed to meet required daily and QA calibrations. Analysis of fuel oil for sulfur content, heat of combustion and carbon continues to be performed per the requirements of 40 CFR Part 75, Appendix D. CEMS 24/7 Software Support contract with Babcock & Wilcox / KVB-Enertec (CEMS NETDAHS) continues to be maintained to ensure proper functionality as well as the integrity of the CEMS data. Maintenance of the software also ensures compliance with current rules or regulations or changes made by the EPA, State and Local Agencies. Training on the Operation and Maintenance of the system, as well as rule/regulation changes continue as needed.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $148,242 or 19.6% lower than previously projected. The variance is primarily due to the following reasons:

- Fewer oil sample analyses were required than previously projected due to reduced oil combustions as a result of lower than projected gas prices.
- Lower than projected costs for Data Acquisition and Handling System (DAHS) 24/7 software support that resulted from vendor discounted unit support fees as the number of total units supported under the contract has increased.
- Lower than projected costs associated with CEMS routine maintenance at Ft. Lauderdale, Putnam, Sanford, Pt. Everglades, and Ft. Myers plants due to less run time as a result of lower than projected natural gas prices and fewer parts required to be replaced.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
This is an ongoing project. Each reporting period will include the cost of quality assurance activities, training, spare parts, calibration gas, and software support.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $816,398.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M**
Project No. 5a

Project Description:
Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections will be completed for this year and all 2012 tank registration fees have been paid. As of 8/6/12, all corporate tanks, which were due for internal & external API inspections in this reporting period, were inspected with no significant mechanical deficiencies or findings to report. Total of two (2) internal and five (5) external API inspections were conducted in the reporting period. Tank PPE-904's internal liner was replaced and returned to service in March, 2012. Lastly, Putnam Plant Tank-G had a complete external coating completed in the second quarter of 2012. Our original plan had a touch-up coating job scheduled but the conditions of the tank required a complete recoating to be performed.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $466,470 or 21.3% lower than previously projected. The variance is primarily due to opportunities to eliminate storage tank work previously projected for 2012. At the time of the original projection filing, it was not yet clear whether the Port Everglades plant would be modernized. As a result of the approval of the modernization project at the Port Everglades plant, the Fuel Oil Terminal facility will be decommissioned in 2013, and therefore the replacement of asphalt storage tank aprons on tanks 801, 802, 807 and 808 at the terminal was not performed. Additionally, with the decommissioning planned for Sanford Unit 3 in 2013/2014, an Alternate Procedure was submitted to the Florida Department of Environmental Protection (FDEP) requesting to forego the API-653 internal tank inspection on Sanford Plant Units 3A, 3B and light oil tanks scheduled for August 2012 and proceed to decommissioning and clean closure in 2013/2014. Concurrence from the FDEP on our Alternate Procedure is forthcoming. Finally, there were lower than projected mechanical repairs resulting from the Martin Fuel Terminal T-1271B Storage Tank API internal inspection.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
This is an ongoing project and each reporting period will include ongoing maintenance of above ground fuel storage tanks in accordance with F.A.C. Chapter 62-761. During the fourth quarter of 2012, the API internal inspection of Tank TMT-1271A will be accelerated because the plants fuel specifications are changing in 2013 from 1.0% Sulfur to 0.7% Sulfur.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $3,588,041.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Oil Spill Cleanup/Response Equipment - O&M**
Project No. 8a

Project Description:
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Plan updates continue to be performed and filed for all sites as required. Routine maintenance of all oil spill equipment has continued throughout the year as well as the performance of spill management drills, including deployment drills throughout the system. A corporate team deployment drill will also be conducted in November 2012 at our Manatee Fuel Oil Terminals. Additionally, several HAZWOPER Training sessions will be conducted for new employees of the site initial team that do not currently hold the required HAZWOPER training certification required of an initial responder or supervisor.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $190,461 or 89.6% higher than previously projected. The variance is primarily due to the development and deployment of Hazardous Worker Operations Training (HAZWOPER) 40hr, 24hr, 8hr and Incident Command Training required for FPL's Oil Spill Response teams to be in compliance with OPA 90 regulations. With updates to the facility response plans in the first quarter of 2012, a substantial gap was indentified in the number of HAZWOPER trained personnel on the Initial Spill Response teams and Corporate Oil Spill response team. The majority of these costs are associated with third party vendors that provide this specialized classroom training.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
This is an ongoing project. Each reporting period will include ongoing maintenance of all oil spill equipment in accordance with OPA 90. Additionally, following a formal assessment of the oil spill program, FPL retained a contractor to perform the mandated OSRO (oil spill removal organization) function. This contractor also performs required maintenance on the oil spill equipment at all of the power plants as well as performs required annual equipment deployment drill at these facilities.

FPL has retained a spill management company to assist in corporate-level responses, improve the Fleet's ability to mobilize spill equipment (specifically boats), and continue to certify all oil spill response members in the NIMS mandated Incident Command System (ICS).

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $291,863.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **RCRA Corrective Action - O & M**
Project No. 13

Project Description:
Under the Hazardous and Solid Waste Amendments of 1984 (amending the Resource Conservation and Recovery Act, or RCRA), the U.S. EPA has the authority to require hazardous waste treatment facilities to investigate whether there have been releases of hazardous waste or constituents from non-regulated units on the facility site. If contamination is found to be present at levels that represent a threat to human health or the environment, the facility operator can be required to undertake "corrective action" to remediate the contamination. In April 1994, the U.S. EPA advised FPL that it intended to initiate RCRA Facility Assessments (RFAs) at FPL's nine former hazardous waste treatment facility sites. The RFA is the first step in the RCRA Corrective Action process. At a minimum, FPL will be responding to the agency's requests for information concerning the operation of these power plants, their waste streams, their former hazardous waste treatment facilities, and their non-regulated Solid Waste Management Units (SWMUs). FPL may also conduct assessments of human health risks resulting from possible releases from the SWMU's in order to demonstrate that any residual contamination does not represent an undue threat to human health or the environment. Other response actions could include a voluntary clean-up or compliance with the agency's imposition of the full gamut of RCRA Corrective Action requirements, including RCRA Facility Investigation, Corrective Measures Study, and Corrective Measures Implementation.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The March 5, 1999 Consent Order for St Lucie Nuclear Plant is amended by the new agreement, with the objective to achieve a no further action either with or without controls. Seven contaminated areas at St Lucie Nuclear are included in the amended agreement and amended consent order that will require continued monitoring, reporting and ultimate site rehabilitation. FPL and the FDEP have the option to defer further assessment and/or remediation until the nuclear plant is decommissioned as directed under the authority of the Nuclear Regulatory Commission. In July, 2012, the site submitted a restrictive covenant document for the area known as the Former Fueling Facility to the FDEP, which was signed by the St Lucie Site Vice President. A final, FDEP approved document is anticipated to be returned by the end of September, 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $76,000 or 76% lower than previously projected. The variance is primarily due to delays in receiving the final approval of the deed restriction package from the FDEP. The work plan for completion has been deferred until approval is received.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The new agreement and consent order included requirements for FPL to manage site rehabilitation of several contaminated areas at the St. Lucie Nuclear Plant, and provided options for closure of these areas under the RCRA program. In support of the amended agreement and amended consent order and in response to FPL's report to FDEP's expected impact, FDEP issued a letter to FPL on April 15, 2011, requiring numerous actions. In order to meet the conditions of these agreements, FPL recommended that FDEP consider a status change for the contaminated areas from "active remediation" to "no further action with controls" as allowed by the RCRA Contaminated Sites Program. The final approved site rehabilitation completion order is expected to be received for the Former Fueling Facility by the end of 2012. A no further action with controls proposal was submitted to the FDEP in February, 2012 for the turbine lube oil and transformer sites.

Project Projection:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $50,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **NPDES Permit Fees – O&M**
Project No. 14

Project Description:
In compliance with State of Florida Rule 62-4.052, FPL is required to pay annual regulatory program and surveillance fees for any permits it requires to discharge wastewater to surface waters under the National Pollution Discharge Elimination System. These fees effect the Florida legislature's intent that the Florida Department of Environmental Protection's (FDEP) costs for administering the NPDES program be borne by the regulated parties, as applicable. The fees for each permit type are as set forth in the rule, with an effective date of May 1, 1995, for their implementation.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The NPDES permit fees were paid to FDEP for power generation operating plants and nuclear plants.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $40,875 or 35.5% lower than previously projected. A reversing entry was recorded in February 2012 for 2011 costs associated with the NPDES permitting renewal process that were inadvertently charged to the environmental clause. Additionally, a correcting entry was recorded in April 2012 for a chlorination study performed at the St. Lucie plant as a result of a permit renewal condition that should have been charged to Project 47 – NPDES Industrial Waste Water Permits in 2011.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The NPDES annual regulatory program and surveillance fees were paid to FDEP for power generation operating plants and nuclear plants.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $115,200.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Disposal of Noncontainerized Liquid Waste - O&M**
Project 17a

Project Description:
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Repair to the ash press included a railing repair that was completed in August 2012. Work at Turkey Point is scheduled for completion in September 2012 with work at Manatee to follow.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $59,748 or 27.0% lower than previously projected. The variance is primarily due to work at Port Everglades Plant that was originally budgeted in the ECRC that will now be charged to the Port Everglades Modernization Project. The work at Port Everglades Plant included site remediation and removal of the ash basins.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
This is an ongoing project. The frequency of basin clean out is a function of basin capacity and rate of sludge/ash generation.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $161,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Substation Pollutant Discharge Prevention & Removal - O&M
Project No. 19a, 19b, 19c

Project Description:
Florida Statute Chapter 376 Pollutant Discharge Prevention and Removal requires that any person discharging a pollutant, defined as any commodity made from oil or gas, shall immediately undertake to contain, remove and abate the discharge to the satisfaction of the department. Florida Statute Chapter 403 states it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The equipment leak repair and regasketing work continues. The arsenic in soils and/or groundwater continues to be addressed at six (6) substations located in Miami-Dade County. All arsenic-impacted soils at these substations are anticipated to be completely managed by the end of this year. A groundwater treatment system to clean-up the arsenic-impacted groundwater has been operating successfully at the University and Lawrence Substations. A groundwater treatment system is currently being designed for the Coconut Grove and Princeton Substations. A restrictive covenant is progressing for the Overtown Substation. The covenant and closure of this substation is expected to be achieved by the end of this year.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)

- 19a. Project expenditures are estimated to be $1,269,224 or 45.0% lower than previously projected. The variance is primarily due to manufacturing delays in the delivery of certain transformer components (e.g., radiators and bushings) from vendors, which has caused a reduction in the work schedule. These components are needed prior to performing transformer regasketing work. The components are expected to be delivered early next year.
- 19b. Project expenditures are estimated to be $23,091 or 2.3% lower than previously projected.
- 19c. No variance expected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
FPL's leak repair and regasketing work activities of oil-filled equipment is progressing. Many transformers require the replacement of components (e.g., radiators, bushings) prior to completing the regasketing work. The deliveries of some components were delayed due to backorders which resulted in a reduction in our work schedule. However, some components have been received, and the regasketing repair work is anticipated to increase toward the end of the year. Equipment encapsulation work is planned for two breakers in 2012. However, there are tentative plans that these two breakers will be entirely replaced in the near future. Once confirmed, we plan to eliminate this program. Environmental remediation work continues at six substations located in Miami-Dade County due to various degrees of arsenic contamination. Major remediation work to clean-up the arsenic-impacted groundwater at the University and Lawrence Substations has been successfully pursuing. A groundwater treatment system is being designed for the Coconut Grove and Princeton Substations. All the remediation work is being conducted under the direction of the Miami-Dade County Regulatory and Economic Resources Department.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are:

- 19a $1,916,262
- 19b $1,221,815
- 19c ($560,232)

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater/Stormwater Discharge Elimination & Reuse - O&M
Project No. 20

Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants, and the Dade County DERM requires the Turkey Point and Cutler plants' wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The project is on hold due to the Pt. Everglades ESP Project.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The project is on hold due to the Pt. Everglades ESP Project.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **St. Lucie Turtle Net – O&M**
Project No. 21

Project Description:
FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service ("NMFS"). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years. An effective 5-inch primary barrier net is vital to limiting the number of lethal turtle takes per year. In 2002, the existing net became deformed due to the influxes of jellyfish and algae entering the canal. With the Commission approval, a replacement and enhancement of the net system was performed. In 2007, the antifoulant and protective coating on the existing 5-inch net deteriorated and was experiencing UV damage. With Commission approval, FPL purchased and installed a new 5-inch net in 2009.

In October 2009, the 5-inch primary barrier net failed due to influxes of algae that entered the canal and created a blockage of approximately 80% of the net. The net is currently in a temporary configuration, which has created an effective temporary barrier for turtles. The Turtle Net project now requires the engineering, construction and installation of a more robust barrier structure that can withstand significant algal events and similar environmental challenges. The proposed design would include the removal of the damaged piles and installation of new piles and a support structure to effectively secure the net.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Engineers have proposed and are currently designing a more effective barrier structure that will include a method for tensioning the turtle net and the design of a portable lift station. Engineering is also working on a design to improve the debris handling capability of the structure in order to provide improved access for maintenance of the net.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Engineering vendor was selected and drawings are to be received by fourth quarter of 2012. Site certification approval process is expected to commence during the fourth quarter of 2012. The current net will remain in a temporary configuration until the new structure is constructed. Engineering of the structure will continue through 2012. Construction activities on the net is planned to begin first quarter 2013.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) – O&M
Project No. 22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid / gas pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The ongoing integrity assessments were undertaken for the corporate liquid/gas pipelines along with associated evaluations and appropriate countermeasures. Smart Pigging of the TMR-30 pipeline was conducted during 4Q2011 with confirmatory and remedial repairs on that pipeline being performed in 2012. The low earthen cover on the TMT 16 inch pipeline was risk ranked and remedial action has been completed on one (1) known areas of no topsoil coverage in March, 2012. We intend to address another area of low earthen cover during 4Q12 - when soil conditions dry and allow for proper excavation and earthworks. Further actions are required in 2013 and 2014 to address the remaining higher risk locations. Annual Public Awareness Campaign was improved and will be conducted in August, 2012. Lastly, upgrades to pipeline block valve control system field devices and telemetry devices (modems) is scheduled for 4Q12.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $46,708 or 9.8% lower than previously projected. The variance is primarily due to lower than estimated costs for work completed to remediate an area of low pipeline ground cover along the pipeline at Manatee Terminal found during a routine inspection.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Inline inspection projects on FPL's TMR-18 and TMT-16 pipelines will continue on a 5-year interval based on observed condition and DOT regulations. Inline inspection of our TMR-30 pipeline will continue on a 3-year interval based on our integrity management program. Repairs program to address TMR-30 pipeline's external corrosion at field joints will continue into 2014. Pipeline Awareness Program (PAP) public outreach will continue annually.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $293,500.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (Spill Prevention, Control, and Countermeasures) - O&M
Project No. 23

Project Description:
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- Has a combined aboveground oil storage capacity of more than 1,320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and
- Due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002. A deficiency was found at the St, Lucie Unit 2 Diesel Oil Storage Tank and refueling tank areas. In order to meet compliance regulations, these areas are required to have secondary containment systems installed. For compliance, it is necessary to install oil berms, designed to catch any spilled oil upon delivery, in these areas.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
FPL is continually updating the SPCC plans for 625 substations. The updates are required to maintain compliance when oil-filled equipment is relocated, removed, upgraded, or added to the substation. Oil diversionary structures are being repaired and new structures are being installed at certain substations. We are currently using alternative oil diversionary products such as interlocking plastic sheeting and polymer-filled booms to provide a more effective and long lasting means to contain oil releases. Inspections of all substations, which are required by SPCC regulations, are being performed on a quarterly basis with the information being captured in a complex database.

FPL began demolishing an aboveground oil water separator at the Sanford Plant, July 30, 2012. Construction will include a new oil waster separator and two associated pumps. Project projected completion date is September 1, 2012. FPL is continually updating the Facility Response Plans for all electrical power plants and terminals. These updates incorporate changes to equipment and containment throughout the year.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $180,585 or 18.9% higher than previously projected. The variance is primarily due to costs that were reclassified from Capital to O&M. The replacement of Sanford Plant's Oily Water Separator was identified as not being a full replacement of the system and therefore, did not meet the capitalization policy. In addition, Martin Units 3 and 4 had unplanned repairs to the secondary containment around the diesel storage tank. The unplanned repairs included concrete cracks and expansion joint repairs. This variance was partially offset by a decrease in the substation oil diversionary structure (i.e., perimeter curbing) repair, which was deferred in order to negotiate new contracts with vendors.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The updating of the 625 substation SPCC plans is ongoing. FPL continues to work on planning and conceptual engineering for additional facility upgrades. Additionally, due to the large number of quarterly substation inspection reports that are being generated, FPL is continuously using a complex database to manage all SPCC-required information. This database has proven to be an efficient and effective method of gathering information to identify compliance issues that need to be addressed. FPL continues to explore new automated methods to be proactive in maintaining SPCC compliance. FPL is continually updating the Facility Response Plans for all electrical power plants

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

and terminals. These updates incorporate changes to equipment and containment throughout the year to maintain SPCC regulation compliance.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $931,256.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Manatee Reburn – O&M**
Project No. 24

Project Description:
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process divides the furnace into three zones.

In the 1996-97 time period, FPL invested considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, and pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The units continue to operate reliably and minor tuning of the process continues. The systems have achieved significant NOx emission reductions. The PMT Reburn O&M ECRC dollars cover all on-going burner and equipment maintenance costs associated with the project. Unit 2 Combustion Air Dampers were repaired as a result of damages found during an inspection in the spring of 2012. Funding was requested and approved to inspect and repair Unit 1 Combustion Air Dampers during the ESP outage starting Fall 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $258,659 or 28.7% higher than previously projected. The variance is primarily due to a shift in work at Manatee Plant from 2011 to 2012 due to changes in the outage schedules that occurred after the approval of the 800 MW ESP project. This work includes the replacement of the Unit 1 and 2 Burner Scanners and Igniters, Unit 1 and 2 Burner Guide Tube Assemblies and Unit 1 Burner Swirlers.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Unit 1 & Unit 2 are operating as referenced above. Project expenditures are based on runtime and available maintenance time.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $500,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pt. Everglades ESP Technology – O&M
Project No. 25

Project Description:
The requirements of the Clean Air Act direct the Environmental Protection Agency to develop health-based standards for certain "criteria pollutants". i.e. ozone (O3), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The DEP's Title V permit for FPL Port Everglades plant requires FPL to install and maintain Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The ESP engineering design for Units 1–4 was completed in 2004. All four units' ESPs were completed between 2005 and 2007 and are operational (O&M activities started in April 2005 for this project).

The installation of the new Kirk Key Interlock System for all units (1&2, and 3&4) was completed in 2011.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $308,749 or 48.2% lower than previously projected. The variance is primarily due to lower than anticipated unit operation on fuel oil as a result of lower than projected natural gas prices. In addition, projected costs associated with the ESP overhaul at the Port Everglades plant will not be incurred. As a result of the modernization of the facility in 2013, the overhaul will no longer be performed.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Construction on all four ESPs was completed and all four units ESPs are operational.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $24,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **UST Replacement/Removal – O&M**
Project No. 26

Project Description:
The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.
UST Category-B tanks are tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have a secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST shall have secondary containment if installed after December 10, 1990.
UST and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
There were no activities in 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are for 2012 are $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Lowest Quality Water Source (LQWS) – O&M**
Project No. 27

Project Description:
Section 366.8255 of the Florida Statutes provides for the recovery through the ECRC of "environmental compliance costs" which are costs incurred in complying with "environmental rules or regulations." The LQWS Project is required in order to comply with permit conditions in the Consumptive Use Permits (CUPs) issued by the St. Johns River Water Management District (SJRWMD or the District)) for the Sanford Plant. Those permit conditions are intended to preserve Florida's groundwater, which is an important environmental resource. The permit conditions therefore "apply to electric utilities and are designed to protect the environment" as contemplated by section 366.8255. The SJRWMD adopted a policy in 2000 that, upon permit renewal, a user of the District's water is required to use the lowest quality of water that is technically, environmentally and economically feasible for its needs. This policy was implemented for the Sanford Plant in the current CUPs. For the Sanford facility, Condition 15 of CUP No. 9202, issued in June 2000, requires the lowest quality of water to be used that is feasible to meet the needs of the facility. The LQWS project at Sanford Plant is currently operational.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The project at the Sanford Plant is currently operational.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $6,768 or 2.1% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The project at the Sanford Plant is currently operational.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $329,309.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **CWA 316(b) Phase II Rule – O&M**
Project No: 28

Project Description:
The Phase II Rule implements section 316 (b) of the Clean Water Act (CWA) for certain existing power plants that employ a cooling water intake structure and that withdraw 50 million gallons per day (MGD) or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans or other Waters of the United States (WUS) for cooling purposes. The Phase II Rule establishes national requirements applicable to, and that reflect the best technology available (BTA) for the location, design, construction and capacity of existing cooling water intake structures (CWIS) to minimize adverse environmental impacts. The Phase II Rule has implications at the following FPL facilities: Cape Canaveral, Cutler, Fort Myers, Lauderdale, Port Everglades, Riviera, Sanford, Martin, Manatee and St. Lucie Power Plants.

A new proposed 316(b) Rule entitled Cooling Water Intake Structures at Existing and Phase I facilities (Existing Facilities Rule) was published in the Federal Register on April 20, 2011. A Consent Decree with Riverkeeper required EPA to sign the final Existing Facilities Rule by July 27, 2012; however, in July 2012 EPA announced that the deadline had been extended for one year. The Existing Facilities Rule, as proposed, will regulate cooling water intake structures from power plants and industries that withdraw threshold limits of cooling water from waters of the U.S. The rule requirements are designed to reduce adverse environmental impacts that result from the impingement and entrainment of aquatic organisms by requiring facilities to install Best Technology Available to reduce the impacts to cooling water intakes.

The Existing Facilities Rule replaces the previous 316(b) Phase II Rule for Existing Facilities (Phase II Rule), that was issued in 2004 and challenged by environmental groups and six northeastern states. The Phase II Rule was subsequently remanded to the EPA by the Second Circuit Court of Appeals after aspects concerning cost to benefit analysis were ruled upon by the U.S. Supreme Court.

FPL's current CWA 316(b) Phase II Project was approved by the Commission in Order No. PSC-04-0987-PAA-EI, issued October 11, 2004. The project included the recovery of costs associated with work required to respond to EPA requirements that facilities covered by the Phase II Rule complete and submit Comprehensive Demonstration Studies to determine the effect of cooling water intake structures on aquatic life. Additionally, in 2008, Order No. PSC-08-0775-FOF-EI approved the recovery of legal and consulting activities associated with protecting the interests of FPL and its customers in the Phase II Rule development. The cost for these activities was projected to be $525,000. To date, however, FPL has not had to spend any of this projected amount because we have been able to work within the Utility Water Act Group and the Edison Electric Institute to have the Supreme Court rule on the 316 (b) Phase II Rule without assistance from outside consultants or outside legal counsel retained by FPL.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
In May 2012, EPA secured an additional year to finalize the rule under a modified settlement agreement. The Agency is working to finalize the standards by June 27, 2013. EPA issued two Notices of Data Availability (NODA) in mid-June that described flexibilities EPA is considering as part of the impingement mortality limitations and that described the preliminary results of surveys of households' willingness to pay for incremental reductions in fish mortality. This extension will allow EPA to complete analysis of data, options and public comments on the NODAs prior to finalizing the rule. On July 11, 2012, FPL submitted comments on the NODA to EPA.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $1,111,073 or 93.9% lower than previously projected. EPA announced on July 18, 2012 that issuance of the new 316(b) rule would be delayed until July 27, 2013 (although this does not preclude EPA from issuing it earlier). As a result, it is now anticipated that originally projected 2012 costs for studies will be spent in 2013. Also, costs for Manatee, Sanford and Putnam plants with closed cooling systems were removed from the budget since it is unlikely that the final rule will apply to these plants. Since the rule is not final, these revised estimates are subject to change pending the specific documentation and schedule requirements in the final rule.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The NODA that EPA issued suggests that the agency is considering more flexibility in implementing the proposed impingement standards, including relief from the mortality standard and monitoring. FPL provided EPA with positive feedback on these aspects. Although an additional year has been granted for rule finalization, EPA may not wait the full year to issue the rule.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $264,108.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **SCR Consumables - O&M**
Project No. 29

Project Description:
The Manatee Unit 3 and Martin Unit 8 Expansion Project Final Orders of Certification under the Florida Power Plant Siting Act and the PSD Air Construction Permit require the installation of SCRs on each of the plants' four Heat Recovery System Generators (HRSG) for the control of nitrogen oxide (NOx) emissions. The Florida Department of Environmental Protection (FDEP) made the determination that the SCR system is considered Best Available Control Technology (BACT) for these types of units, with concurrence from the U.S. Environmental Protection Agency (EPA). The operation of the SCRs will cause FPL to incur O&M costs for certain products that are consumed in the SCRs. These include anhydrous ammonia, calibration gases, and equipment wear parts requiring periodic replacement such as controllers, ammonia detectors, heaters, pressure relief valves, dilution air blower components, NOX control analyzers and components.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The SCR systems are operational on both Manatee Unit 3 and Martin Unit 8. An inspection of the ammonia injection system is required in 2012 on Units C and D at a cost of approx. $70,000. This is a required, repetitive inspection to determine remaining catalyst life.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $144,143 or 41.2% higher than previously projected. The variance is primarily due to unexpected repairs of the Anhydrous Ammonia tank at the Martin and Manatee plants found during the planned inspection required by the plants' risk management plans per the Air Permit Facility-Wide Conditions (FW9), and by regulation under 40 CFR Part 68. The Anhydrous Ammonia tank required repairs to fittings that were showing signs of corrosion at several locations on the tank. The ammonia system had to be drained in order to repair the fittings and as a result ammonia costs increased. In addition, there were unanticipated costs associated with the inspection of the ammonia piping at the Manatee plant. As part of the plants' risk management plans, this inspection will occur every five years and will require a piping Non Destructive Examination (NDE) inspection, pipe coating and the removal of pipe lagging.

Project Progress Summary:
(January 1, 2012 December 31, 2012)
The SCR systems are operating reliably on both Manatee Unit 3 and Martin Unit 8.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $350,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Hydrobiological Monitoring Program (HBMP) - O&M**
Project No. 30

Project Description:
The Hydrobiological Monitoring Program is required by the Water Management District in the Conditions of Certification for Manatee Unit 3. The program involves the data collection of river chemistry, flow and vegetation conditions to demonstrate that the plant's withdrawals do not impact the environment in and along the river. The Hydrobiological Monitoring Program is a 10 year study which started in 2003 during the construction phase of Unit 3 and will be completed in 2013.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Continue with river monitoring, calibration, maintenance and data collection. Vegetative mapping, aerial photography and mapping will be conducted during the fall of 2011, for reports due in 2013. A Data Summary Report was completed in March 2011. In May thru July 2012, additional data was gathered to report effects of the Emergency Diversion Schedule (utilized May thru July 2012) on river quality. Data acquisition and analysis, along with a report to SWFWMD is required any time the Emergency Diversion Schedule is used. A charge of ~ $8200 will be incurred for this work in 2012

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
There is no variance.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
This is an ongoing project.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $22,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **CAIR – O&M**
Project No. 31

Project Description:
In response to the EPA Clean Air Interstate Rule (CAIR), FPL initiated the CAIR Project to implement strategies to comply with Annual and Ozone Season NOx and SO2 emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, the costs for the operation of SCR's constructed on SJRPP Units 1 and 2, costs for the operation of the Scrubber and SCR being installed on Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in a cycling mode. The study costs to Aptech Engineering have been paid and a significant portion of the work has been completed on the Martin and Manatee 800 MW units. Several countermeasures that were prioritized and scheduled for implementation in 2008 – 2011. The CEMS installation on the Gas Turbine Peaking Units has been completed with ongoing maintenance expenses for their operation. On December 3, 2008 Georgia EPD promulgated the GA Multi-Pollutant rule requiring installation of SCR and a Scrubber on Scherer Unit 4. Recently, on July 6, 2010, EPA proposed the Transport Rule, which will leave requirements to comply with the CAIR regulations in place until 2012 when a new program will be implemented to further reduce So2 and NOx emissions from fossil power plants.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
800MW Cycling Project - The A and B Boiler Feed Pump recirculation regulators were inspected at Martin 2. Martin has removed the isolation valves on the Controlled Extraction, valves on the Mass Blowdown Automation, as well as the control valves on the Spray Upgrades. The Water Induction Protection bridal piping was removed at Martin. Manatee 1 has had these projects installed. Manatee 1 also had the A and B BFP recirculation valves replaced. Three throttle valves were shipped off for refurbishment and SPE coating and returned. The Water Treatment Plant lease payments have started for both Martin and Manatee.

St. John's River Power Park (SJRPP) 1&2 SCR construction is in progress. Construction was completed on the Scherer FGD and SCR in May 2012. Performance guarantee testing of the SCR was completed in June 2012 and it is now in operation. Performance guarantee testing of the FGD is projected to be completed in August 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $1,120,991 or 24.1% lower than previously projected. The variance is primarily due to lower than expected operating expenses of the Scherer Unit 4 Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) as a result of a change in the start of the planned duct tie-in outage in 2012. This resulted in the final installation and testing of the SCR and FGD to occur later in the year than originally projected which reduced expected operating expenses. The SCR completed testing and was placed in service June 14, 2012 and testing of the FGD is expected to be completed in August 2012. Ammonia injection costs decreased as a result of less operating hours of the SJRPP SCR due to cost efficiencies. In addition, subsequent to FPL's projection of anticipated legal costs for challenging the Clean Air Interstate Rule (CAIR), on December 23, 2011, the U.S. Court of Appeals for the D.C. Circuit unexpectedly stayed the CSAPR rule, resulting in lower than projected legal expenses for 2012.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
As part of the 800 MW Cycling project the A and B Boiler Feed Pump recirculation regulators were inspected at Martin 2 and Manatee 1. Martin 2 and Manatee 1 have removed the isolation valves on the Controlled Extraction, valves on the Mass Blow-down Automation, as well as the control valves on the Spray Upgrades. The Water Induction Protection bridal piping was removed at Martin 2 and Manatee 1. Lease payments for the water treatment plant additions required at both Manatee and Martin have begun.

FPL's CAIR project at SJRPP U1 & 2 continues with both SCRs in operation. O&M expenses for reagents and maintenance will be ongoing. FPL's share of O&M costs associated with the CAIR Scrubber and SCRs at plant Scherer started in 2011 as common plant facilities were placed in service. Unit specific O&M expenses for the FGD and SCR started in 2012 after construction was completed and will be ongoing.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $8,675,688.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **BART Project – O&M**
Project No. 32

Project Description:
Conduct air dispersion modeling to determine the visibility impacts to Federally Mandated Class 1 Areas (National Parks, National Wilderness Areas, etc.) from FPL's BART-Eligible units. The Regional Haze Rule, renamed the Clean Air Visibility Rule, (CAVR) mandates that certain vintage electric generating units (ca. 1962-1977) install Best Available Retrofit Technology (BART) if it is shown, via modeling that a unit causes or contributes to visibility impairment in any Class 1 Area.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
As a result of the D.C. Circuit Court of Appeals vacatur of CAIR and the subsequent determination that compliance with CAIR equals BART, FPL was then required to develop 5-factor BART determinations for those sources formerly exempt. To comply with the analysis requirements to determine what is the Best Available Retrofit Technology (BART) for each FPL BART-eligible source, FPL had to assess the following 5-factors: 1) The cost of compliance; 2) The energy and non-air quality environmental impacts of compliance; 3) Any existing pollution control technology in use at the source; 4) The remaining useful life of the source, and; 5) The degree of visibility improvement which may reasonably be anticipated from the use of BART. The required visibility modeling and BART determinations were made for Putnam 1&2, Manatee 1&2, Martin 1&2 and Turkey Point 1&2. The determinations were submitted to FDEP in 2012 for submittal in the Florida Regional Haze SIP to EPA.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $15,900, versus an original estimate of $0. As a result of the Circuit Court's vacature of CAIR, Florida's Regional Haze State Implementation Plan (SIP), which relied on EPA's assertion that CAIR was equal to BART (Best Available Retrofit Technology), was no longer valid for emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) which were part of the Clean Air Visibility Rule (CAVR). Therefore, several of our BART-eligible plants that were formerly exempt from BART controls for SO2 and NOx (Putnum Units 1 and 2, Turkey Point Units 1 and 2, Manatee Units 1 and 2, and Martin Units 1 and 2), are now required to develop 5-factor BART determinations and conduct visibility modeling to satisfy the BART requirements of CAVR. This was unanticipated until late 2011. The additional charges are consultant fees to develop the BART determinations and visibility modeling for the four plants identified above.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Submitted BART application for exempt facilities (PCC, PMR, PMT, PPE, PRV) to FDEP on January 31, 2007. BART determination for PTF was submitted to the FDEP. FDEP requested additional information on PTF February 26, 2007, which necessitated additional consultant modeling support. Response to FDEP with additional information submitted to FDEP May 3, 2007. FPL and FDEP successfully negotiated the terms of the Draft BART permit for PTF Units 1 and 2 with FPL receiving the final permit on April 14, 2009 for installation of new dust collectors in 2012. In 2012 FPL submitted a request to modify Turkey Point 1&2 BART permit on 01/25 to: a) remove the requirement to install new dust collectors, b) cease burning fossil fuel in Unit 2, and c) limit Unit 1 to an annual 25% capacity factor equivalent for oil fuel firing from December 31, 2013 until the MATS Rule becomes effective or June 1, 2017 whichever comes first. 5-factor BART Determinations were developed for PMT 1&2 and PMR 1&2 and submitted to FDEP on May 30, 2012. The PMT BART Determination proposed a reduction in fuel oil sulfur from 1.0% to and equivalent 0.7% and the addition of ESPs on Units 1&2. PMR proposed no changes with the exception of adding ESPs to Units 1&2 which are required under the EPA Mercury and Air Toxics Standards rule. We received the final modified BART permit for PTF on July 2nd, which included all of our proposed BART elements, including the withdrawal of the requirement to install new dust collectors saving approximately $3.7 million..

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **MATS Project – O&M**
Project No. 33

Project Description:
The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on March 15, 2005, imposing nation-wide standards of performance for mercury (Hg) emissions from existing and new coal-fired electric utility steam generating units. The CAMR is designed to reduce emissions of Hg through implementation of coal-fired generating unit Hg controls. In addition, CAMR requires the installation of Hg Continuous Emission Monitoring Systems (HgCEMS) to monitor compliance with the emission requirements. The rule is implemented in two phases with an initial compliance date of 2010 for Phase I and the final required reductions of Phase II in 2018. The State of Florida has begun the implementation of the requirements for reduction of Hg through rule making process. Plant St. John's River Power Park (SJRPP) Units 1 & 2, in which FPL has 20% ownership shares, are affected units under this rule and will require the installation of Hg controls and HgCEMS. Similarly, the State of Georgia has also begun their rule making process to implement the federal rule, which will affect FPL's ownership share of Plant Scherer Unit 4, also requiring the installation of HgCEMS and Hg controls.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The Scherer Unit 4 baghouse was placed into service April 4, 2010. The baghouse passed all performance guarantee tests in May 2010 and is now in continuous operation.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $48,903 or 1.5% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The FPL CAMR project at Plant Scherer includes FPL's costs from the installation of the baghouse, the mercury sorbant injection system with associated controls and material handling equipment, and capital additions to Plant Scherer common areas to accommodate sorbant delivery and storage and spent sorbant disposal. Hg controls at Plant Scherer were installed on all four units at the plant to comply with the Georgia Multi-Pollutant Rule. Installation of controls requires a specific sequence for the construction of the controls and material handling systems. The baghouse on Unit 4 was installed and placed in-service in April 2010. Ongoing O&M costs associated with the CAMR Compliance project include expenses associated with purchase of sorbant used for flue gas Hg removal and disposal of spent sorbant.

Project Projections:
(January 1, 2013 - December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $3,003,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **St. Lucie Cooling Water System Inspection and Maintenance – O&M**
Project No. 34

Project Description:
The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system (the "Cooling System") at FPL's St. Lucie nuclear plant , such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie Plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie Plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion ("BO") that is to be issued by the National Oceanic and Atmospheric Administration ("NOAA") pursuant to section 7 of the ESA. It is anticipated that NOAA will finalize the BO in late 2012 or early 2013. NOAA sent the Nuclear Regulatory Commission ("NRC") a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Cleaning of the 12' north intake pipe and velocity cap vertical section was completed in 2011.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The cleaning of all three (3) intake pipes and velocity cap vertical sections and the concrete removal at all three (3) velocity caps (for the installation of the turtle excluders) was completed in 2011.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Water System – O&M**
Project No. 35

Project Description:
The Martin Drinking Water System (DWS) is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for TTHM (trihalomethanes) and HAA5 (Haleo Acetic Acid). The upgrades to the potable water system will cause FPL to incur capital costs for major component upgrades to the system in order to comply with the new requirements. These include Nano filtration, air stripping, carbon and multimedia filtration. The operation of the potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The project has been implemented. The agency has inspected and approved system startup and testing. The system will continue to run throughout 2011. O&M dollars were expended on filter maintenance and expected until the end of 2011 and into 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
There is no variance explanation needed.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
O&M dollars were expended on filter maintenance and expected until the end of 2010 and into 2011.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $20,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Low Level Radioactive Waste – O&M**
Project No. 36

Project Description:
The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste (LLW) such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. The Barnwell facility ceased accepting LLW from FPL June 30th, 2008. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN is to ensure construction of a LLW storage facility with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5 year period. This will allow continued uninterrupted operation of the PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN will also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The Turkey Point LLW Storage Facility project schedule has been created. The Engineering Package has been completed and issued for construction. A contractor has been selected and contracts are in the process of being created. The construction of the LLW Storage Facility at Turkey Point is planned to commence in September of 2012 and is expected to be completed by September of 2013.

The St. Lucie LLW Storage Facility has been placed on hold in 2012 as a result of resources being dedicated to other projects. Completion of the Facility will resume in January of 2013 with the installation of the fiber optics for the fire detection system, installation of the internal shielding, and the crane rails for the gantry crane.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
No variance is expected. There are no project expenditures projected for 2012.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The construction of the LLW Storage Facility at Turkey Point is planned to commence in September of 2012 and is expected to be completed by September of 2013.

The LLW Project at St. Lucie has experienced some additional schedule delays due to the competition for resources being focused on other projects. This has resulted in delaying the completion of the facility to the 1st quarter 2013. The St. Lucie LLW schedule delay has shifted some of the projected 2010 expenditures for the construction work into 2011 and 2013.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **DeSoto Next Generation Solar Energy Center – O&M**
Project No. 37

Project Description:
The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic generating facility which will convert sunlight directly into electric power. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility will utilize cutting edge solar panel technology. The project will involve the installation of the solar PV panels and tracking system and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Through end of June, 2012, Desoto's net energy production was 79,032 MWHs. No major maintenance events during this time. The primary accomplishment for the year is the installation of a Low Voltage Ride Through system on each inverter. The site is currently transitioning out of the warranty period. Site personnel have initiated a project studying panel degradation by using an IV Curve Tracer. Installation of current transformers on the DC inputs to the inverters is scheduled to begin during the third quarter of the year. This will give site personnel the ability to detect changes in DC generation in the solar array.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $127,739 or 11.5% lower than previously projected. The variance is primarily due to lower than projected costs associated with employee payroll and related expenses, and overheads as a result of obtaining more experience in maintaining the Desoto and Space Coast facilities. It was determined that the site personnel at Desoto could also support Space Coast Next Generation Solar Energy Center reducing the payroll costs and expenses remaining at Desoto. Additionally, planned technical support payroll and expenses were less than projected as a result of less fleet team support.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Desoto achieved Commercial Operation on October 27, 2009 and Final Acceptance on April 27, 2010.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $1,127,902.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Space Coast Next Generation Solar Energy Center – O&M**
Project No. 38

Project Description:
The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW solar photovoltaic (PV) generating facility which will convert sunlight directly into electric power. The facility will utilize a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project will involve the installation of the solar PV panels and support structures and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

The Space Coast project also includes building a 900 KW solar PV facility at the Kennedy Space Center (KSC) industrial area. This 900 KW solar site will be built and operated and maintained by FPL as compensation for the lease of the land for the Space Coast Solar Site which is located on KSC property.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Through end of June, 2012, Space Coast's net energy production was 28,525 MWHs. The site operated with no major maintenance events. The warranty is still in effect until September 30, 2012. Installation of current transformers on the DC inputs to the inverters is scheduled to begin during the third quarter of the year. This will give site personnel the ability to detect changes in DC generation in the solar array.

KSC 1 MW site operated well with no major issues. Through end of June, 2012, net energy production was 2443 MWHs. Quarterly Operation and Maintenance reports were submitted to NASA in accordance with Lease Agreement between NASA and FPL.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $306,336 or 51.2% lower than previously projected. The variance is primarily due to lower than projected costs associated with employee payroll and related expenses, overheads, and contractor services. Two full-time positions included in the original budget will not be filled as maintenance and operations are now covered by personnel stationed at the Desoto Next Generation Solar Energy Center. In addition, the new grounds maintenance contract was renegotiated at a lower monthly cost and planned technical support was less than projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Space Coast Solar Site achieved commercial operation on April 16, 2010 and Final Acceptance is expected by September 30, 2010.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $353,176.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Next Generation Solar Energy Center - O&M**
Project No. 39

Project Description:
The Martin Next Generation Solar Energy Center ("Martin Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam to be supplied by Martin Solar will be used to supplement the steam currently generated by the heat recovery steam generators. The project will involve the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors will track the sun to maintain the optimum angle to collect solar radiation. The collectors will concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Commercial Operation was achieved on December 10, 2010. In the first seven months of operation this year, the plant generated approximately 63,170 MWH of equivalent steam.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $1,059,615 or 42.7% higher than previously projected. The variance is primarily due to higher maintenance costs, employee payroll, and gas usage. The number of solar employees increased from 7 to 15 for a total increase of $577,979 annually. The original staffing of 7 employees was based primarily on the number required to perform basic outside operations duties, inspection of watch, and minor maintenance. FPL planned to determine how much staffing was required after some operational experience and then increase staffing as needed. After several months of operation it became apparent that additional staffing was required to perform operational and maintenance duties. Four of eight employees were added in November, 2011 and the balance were added in January, 2012.

Mirror washing costs have also increased from the original 2012 estimate by $221,000. The original 2012 budget was based on washing mirrors every two weeks. FPL learned subsequently that mirror washing must be performed daily in order to maintain performance. A more aggressive cleaning schedule began in 2012 and will have an annual estimated cost of $459,238.

Additionally, nitrogen gas usage is greater than planned. Nitrogen gas is used to displace the water that mixes with the heat transfer fluid. FPL projects an additional cost of $147,900 for increased gas usage.

Lastly, the preheater leak repairs began in June 2012 in the amount of $175,000. Additional preheater leaks caused FPL to exceed their original maintenance budget.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Commercial Operation was achieved on December 10, 2010. In the first seven months of operation this year, the plant generated approximately 63,170 MWH of equivalent steam.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $3,105,612.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Greenhouse Gas Reduction Program - O & M**
Project No. 40

Project Description:
The purpose of FPL's proposed Electric Utility Greenhouse Gas (GHG) Reduction Program is to implement both the reporting and emission reduction requirements established under Chapter 403 of the Florida Statutes and to comply with the EPA Mandatory GHG Reporting Rule promulgated on October 30, 2009. During the initial implementation of the Florida program, electric utilities, major emitters of GHG's, are required to participate in The Climate Registry providing historical and current (GHG) emission data to establish the baseline emissions and targets for the required compliance reductions to meet the 2017, 2025 and 2050 deadlines. In subsequent years utilities will be required to engage third party verification of their reported inventory. To comply with future GHG Cap and Trade programs FPL will need to recover GHG emission allowance costs through this project as needed. To achieve the future reduction goals established by the executive order, FPL anticipates that additional reductions in its GHG emissions will be required beyond the currently planned fossil unit conversions, nuclear uprates, and the addition of new nuclear generating units. The additional reductions will likely require a combination of the implementation of carbon sequestration and storage technology and the use of verified carbon offset projects. EPA's Mandatory (GHG) Reporting Rule requires electric utilities to record emissions of GHGs, primarily CO2 from the combustion of fossil fuels, and report actual data in a subsequent year. FPL was required to begin reporting GHGs emitted from its fossil generating units annually starting in 2011.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
FPL completed implementation for its GHG Reporting System and successfully reported required facility GHG emissions to the EPA prior to the regulatory deadline. The implementation included the installation and use of a GHG reporting system and the training of those employees responsible for imputing required data.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $58,500 or 97.5% lower than previously projected. The variance is primarily due to the purchase of a GHG reporting software and user training in 2011 subsequent to submittal of final projections for 2012. FPL implemented the system in 2011 earlier than anticipated to address initial implementation issues with sufficient margin prior to the regulatory required reporting deadline.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
FPL has implemented the system and completed one reporting cycle for FPL facilities required to report under the EPA Mandatory GHG Reporting Rule.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are $8,500.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Manatee Temporary Heating System – O&M**
Project No. 41

Project Description:
FPL is subject to specific and continuing legal requirements to provide a warm water refuge for the endangered manatee at its Riviera (PRV) and Cape Canaveral Plants (PCC). FPL has undertaken the design, engineering, purchase, and installation of a temporary manatee heating system at both PRV and PCC ("the Project"). The Project is required pursuant to PRV's and PCC's Manatee Protection Plans (MPP), as part of the State Industrial Wastewater Facility Permit Numbers FL0001546, Specific Condition 13, issued on February 16, 1998 and FL0001473, Specific Condition 9, issued on August 10,2005, respectively. In order to comply with the respective MPP's, FPL's installation of a temporary manatee heating system at PRV and PCC will be implemented to avoid potential adverse impacts to manatees congregating at PRV's and PCC's manatee embayment area. Manatees currently gather at the plants during the annual period from November 15 to March 31 at PRV and the annual period of October 15 to March 31 at PCC. FPL's installation of the Manatee Temporary Heating System at each site must be implemented to provide warm water until the site has completed the planned modernization of the existing power generation units and return of warm water flow from the generating unit cooling water will be provided by operation of the new units.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The Manatee Temporary Heating System at PRV began operations in Q4 2009 and was available throughout the 09/10, 10/11 and 11/12 manatee season. The PCC Manatee Heating System work was completed in September 2010, and the unit was available throughout the 2010/2011 and 2011/2012 manatee season.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $705,074 or 52.8% less than previously projected. The variance is primarily due to lower than expected system operating costs at the Cape Canaveral plant as a result of design enhancements that were identified during the previous manatee heating season (October 2010 through March 2011), as well as unseasonably warm weather. The intake refuge perimeter design enhancement, primarily the addition of a sheet pile wall to minimize the refuge size and open boundary, has improved the capability to maintain the refuge at the required 68°F and thus minimizing the loss of heated water to the Indian River. In addition to the refuge perimeter enhancement, the unseasonably warm weather has resulted in the need to operate the primary heating source less often and no need to operate the supplemental heater. As a consequence, FPL has needed less contracted manpower to operate both heaters, as well as incurring reduced manatee observer labor costs.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The Manatee Temporary Heating System at PRV began operations in Q4 2009 and was available throughout the 09/10, 10/11 and 11/12 manatee season. The PCC Manatee Heating System work was completed in September 2010 and the unit was available throughout the 2010/2011 and 2011/2012 manatee season.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for January 2013 through December 2013 are $930,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Turkey Point Cooling Canal Monitoring Plan - O & M**
Project No. 42

Project Description:
Pursuant to Conditions IX and X of the Florida Department of Environmental Protection's (FDEP) Final Order Approving Site Certification, filed October 29, 2008, FPL submitted its initial draft of the proposed Cooling Canal Monitoring Plan associated with FPL's Turkey Point Uprate Project to the South Florida Water Management District (SFWMD). This plan requires an assessment of baseline conditions to provide information on the vertical and horizontal extent of the hypersaline groundwater plume and effect of that plume on ground and surface water quality, if any. Comments, concerns and requests for revisions or action items were received from the SFWMD as well as the FDEP. Miami-Dade Department of Environmental Resource Management (DERM) has incorporated into the current draft the proposed monitoring plan, dated July 16, 2009.

The TP CCM Plan was finalized by FPL and the agencies on October 14, 2009. The objective of FPL's TP CCM Plan is to implement the Conditions of Certification IX and X, which states that "the Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to surface water, groundwater and water quality monitoring, and ecological monitoring to: delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition; determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate Project. The Revised Plan includes installation and monitoring of an appropriate network of wells and surface water stations.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
FPL received the final CCM Plan on October 14, 2009 from the Florida Department of Environmental Protection (FDEP), South Florida Water Management District (SFWMD) and Miami-Dade County. The Agencies approved the Quality Assurance Project Plan on December 2, 2011. The second Semi-Annual Report was submitted on March 28, 2012. The Comprehensive Pre-Uprate Monitoring Plan will be submitted on October 31, 2012. The Initial Ecological Condition Characterization Report was submitted in June 2012. FPL and the SFWMD conducted two environmental audits each in 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are expected to be $1,245,000 or 94.3% higher than previously projected. The variance is due to various factors. When the original budget was submitted it was assumed that after the first two years of data collection that the sampling and monitoring effort required by the agencies in the Monitoring plan would be reduced by approximately 50%. The agencies have not agreed to any of FPL's request to reduce sampling at this time. The agencies are requiring very detail analysis of the data collected in the semi-annual and annual reports that are a requirement of the Monitoring Plan. The cost of the lab analysis was underestimated, there are only a handful of labs that analyze for some of the specialized parameters that FPL is being required to monitor for and they are expensive. The time required for management of the consultants required the hiring of a project manager at the Turkey Point Site. Additional work such as annual geophysical survey were not anticipate but are being required annually by the agencies. All of this work is necessary to comply with the FPL Turkey Point Power Plant Groundwater, Surface Water, and Ecological Monitoring Plan and the Quality Assurance Project Plan.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Implementation of the CCM is ongoing and will continue throughout the year. Water Quality data collection continues; which consist of daily automated and quarterly water quality analysis in both surface water and groundwater well. Ecological and porewater monitoring is ongoing.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2013 to December 31, 2013)

Estimated project O&M expenditures for the period January 2013 through December 2013 are $2,442,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NESHAP Information Collection Request Project (National Emission Standards for Hazardous Air Pollutants) – O & M
Project No. 43

Project Description:
Pursuant to EPA's authority under Section 114 of the Clean Air Act (CAA), the EPA issued an Information Collection Request (ICR) to coal- and oil-fired electric utility steam generating units in January 2010. Four (4) FPL facilities received this information request from the EPA and were thus required by law to conduct extensive stack testing and oil sampling and analysis on eight (8) units in accordance with an EPA approved protocol. Data from the stack testing and analysis and the oil sampling and analysis was required to be quality assured and submitted to the EPA via the EPA Electronic Reporting Tool (ERT). EPA had solicited comments and any additional data which would assist them in writing the draft and final rules.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
All testing and sampling for the eight (8) units is complete. The final data and analysis reports for five (5) units are complete and have been submitted to the EPA. The final reports for two (2) units were submitted to the EPA on August 28, 2010, and the final report for the last unit will be submitted to the EPA in early September, 2010. FPL provided additional information to EPA on the risk assessment of oil-fired unit acid gasses and emissions of Nickel compounds that demonstrated risks below EPA threshold levels. FPL also filed comments with EPA on August 4, 2011 requesting that EPA reduce testing and reporting requirements, allow limited use units to operate without additional controls, and to not regulate acid gases from oil-fired units.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
No project expenditures are estimated for 2012.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
All testing and sampling for the eight (8) units is complete. The final data and analysis reports for five (5) units are complete and have been submitted to the EPA. The final reports for two (2) units was finalized and submitted to the EPA August 4, 2010. FPL provided additional data and analysis of residual fuel acid gasses and nickel compound emissions. With the close of the comment period on August 4, 2011, FPL does not anticipate any further activities for this project.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project O&M expenditures for the period January 2013 through December 2013 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Barley Barber Swamp Iron Mitigation Project – O & M**
Project No. 44

Project Description:
Martin Plant Barley Barber Swamp Iron Mitigation Project was installed in 2011. The capital project included the installation of complete siphon systems to mitigate iron discharges in the Barley Barber Swamp. The systems will use cooling pond water (low iron) to hydrate the swamp are required by permit.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Capital installation project completed in May 2011. The project is now operational.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $2,150 or 95.6% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The project completed its first official month of operation in June of 2011. All three siphons are in service from the cooling pond to the Barley Barber Swamp.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are expected to be $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **800MW Unit ESP Project – O & M**
Project No. 45

Project Description:
On March 16, 2011 the Environmental Protection Agency (EPA) issued a proposed rule that would reduce emissions of toxic air pollutants from power plants. Specifically, the proposed toxics rule would reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF), from new and existing coal- and oil-fired electric utility steam generating units (EGUs). Following the publication of the proposed rule, on June 21, 2011 EPA extended the timeline for public input by 30 days on the proposed rule accepting comments on the proposal until August 4, 2011. The EPA is expected to finalize the air toxic rule by November 16, 2011. To comply, FPL will install Electrostatic precipitators on Manatee Units 1 & 2 and Martin Units 1 & 2.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Construction on Manatee 2 commenced in 2011 and was completed in June 2012. Construction on Manatee 1 is expected to begin in September 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance of $433,504 is due to O&M expenditures that were not included in the original 2012 projections because the final MATS rule had not yet been issued. On December 21, 2011, EPA issued the final MATS rule, which has the effect of requiring ESPs for the 800 MW oil-fired units. As a result, the revised estimate now includes O&M costs for the August 2012 - December 2012 period.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Construction on Manatee 2 commenced in 2011 and was completed in June 2012. Construction on Manatee 1 is expected to begin in September 2012

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are expected to be $1,447,087.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **St. Lucie Cooling Water Discharge Monitoring Project - O&M**
Project No. 46

Project Description:
In conjunction with the St. Lucie Plant extended power uprates (EPUs) and a Florida Department of Environmental Protection (FDEP) permit modification authorizing a 2 degrees Fahrenheit increase to the plant's discharge temperature limitations, the St. Lucie Plant Industrial Wastewater Facility (IWF) Permit requires FPL to perform biological and thermal monitoring in the Atlantic Ocean, in the vicinity of FPL's St. Lucie Plant, in accordance with an FDEP Administrative Order (AO). The purpose of this monitoring project (biological and thermal monitoring) is to evaluate potential effects of the EPUs on the plant's indigenous ocean biological species and to ensure that the St. Lucie Plant remains in compliance with Florida environmental permits and regulations applicable to the discharge of heated water to an open ocean environment.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Six biological baseline sampling events (four since January 2012) have been performed by Ecological Associates, Inc. (EAI), FPL's contractor for implementation of the biological monitoring plan. The baseline sampling results will be compared with the sampling results obtained following implementation of both EPUs at the St. Lucie Plant.

FPL has submitted permits to the appropriate regulatory agencies to install the required thermal monitoring equipment in the Atlantic Ocean, in the vicinity of the St. Lucie Plant. The Golder Associates team, FPL's contractor for implementation of the thermal monitoring plan, is in the process of procuring, receiving and assembling the thermal monitoring components (anchors, buoys, current profilers and temperature loggers). A field reconnaissance has been performed to identify the locations, in the vicinity of the plant's discharge pipes, where the maximum surface discharge temperatures are observed and where thermal monitors need to be installed to assess plant discharge temperatures.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are $576,195 or 57.7% lower than previously projected. The variance is primarily due to reversing charges that were inadvertently included in the budget for this project. In addition, original estimates were based on initial contract bids. FPL has since received lower than estimated fixed price contracts for portions of the scope of work required. Costs were deferred to 2013 due to a shift in the Extended Power Uprate (EPU) outage schedule.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
As required by the AO, FPL submitted a Biological Plan of Study (BPOS) to the FDEP. The FDEP approved the BPOS for implementation. To date, the project has completed six of eight scheduled baseline sampling events, and is on schedule to perform the remaining two baseline sampling events prior to startup of Unit 2 following its EPU conversion. The data collected during each sampling event consists of obtaining general environmental data; water quality data; numbers and sizes of fish and shellfish collected by gill net, trawl, and beach seine; numbers of fish eggs and larvae and commercially or recreationally important decapod crustacean larvae collected by plankton net; and, numbers and sizes of sea turtles observed. Biological sampling data will be used to assess potential impacts of the EPUs based upon the pre-(baseline) and post-EPU biological monitoring performed.

As required by the AO, FPL submitted an Ambient Monitoring Report (AMR) and a Heated Water Plan of Study (HWPOS) to the FDEP. The ambient monitoring requirements were subsequently subsumed into the HWPOS which was approved for implementation by the FDEP. Implementation of the HWPOS remains on schedule for deployment of the thermal monitoring equipment during the St. Lucie Unit 2 EPU conversion outage. The activities to be performed and the data to be collected during execution of the HWPOS includes deploying, retrieving and downloading continuously monitored ambient and heated water plume temperatures and ocean currents data for assessment of FPL's modeling predictions and compliance with FDEP permits and regulations for discharging heated water to an open ocean environment.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are expected to be $388,941.

Post EPU biological sampling is projected to commence in January 2013. Post EPU biological monitoring will be performed, for a minimum of two years, following startup of Unit 2 (the EPU has been completed on Unit 1) after its EPU conversion as required by the AO and the BPOS.

The HWPOS is on schedule to be implemented following the startup of St. Lucie Unit 2 (the EPU has been completed on Unit 1) following its EPU conversion. Thermal monitoring will be performed, in accordance with the HWPOS, for a minimum of two years, following its implementation, as required by the AO and the HWPOS.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NPDES Permits Project (National Pollutant Discharge Elimination System) – O & M
Project No. 47

Project Description:
The Federal Clean Water Act requires all point source discharges into navigable waters from industrial facilities to obtain permits under the NPDES program. See 33 U.S.C. Section 1342. Pursuant to the U.S. Environmental Protection Agency's delegation of authority, FDEP implements the NPDES permitting program in Florida. Affected facilities are required to apply for renewal of the 5-year-duration NPDES permits prior to their expiration. In April 2009, the FDEP amended Rule 62-620.620 (3), F.A.C. requiring all new or renewed wastewater discharge permits for major facilities, including power plants, to contain whole effluent toxicity (WET) limits. Additionally, FDEP has required that facilities prepare a Storm Water Pollution Prevention Plan (SWPPP) that conforms to Rule 62-620.100 (m), F.A.C. and 40 CFR Part 122.44(k) when the NDPES permits are renewed. The purpose of the SWPPP is to identify possible pollutant sources that can affect the water quality of stormwater and to require best management practices (BMPs) that, when implemented, will reduce or eliminate any possible pollution impacts to stormwater. FPL had several NPDES permits renewed in 2011 and 2012, and all of FPL's NPDES permits will have to be renewed over the next five years. In late September of 2012, the St. Lucie Plant received a final NPDES permit which contained a requirement to conduct a total residual oxidant plan of study (TROPOS) that will demonstrate that the discharges from the PSL cooling water system meet the State's Class III total residual oxidant water quality standard of 0,01 mg/l. FPL has requested that cost for the TROPOS be added to this project.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
48a. WET Testing – WET testing has been conducted at PPE, PFL, PFM, and PSL in 2012. PRV, PCC and PCU have WET Testing requirements in their NPDES permits but the facilities are not operating so sampling is not required until they do operate. 48b – SWPPP Development –the SWPPP for PFM was developed in 2012, however it was written by FPL staff so no ECRC costs were incurred.. 48c – TROPOS – A proposed TROPOS has been submitted to FDEP and work required by the TROPOS should begin as soon as it is approved by FDEP, which will most likely be in the latter part of 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $27,076 or 36.8% higher than previously projected. The variance was primarily due to a chlorination study that was required to be conducted by the St. Lucie Plant NPDES permit renewal that was not included in the original projections.

On August 9, 2012, FDEP approved the TROPOS and FPL received a revised estimate from a vendor for the completion of the TROPOS based on the approved TROPOS. FPL now anticipates spending $59,953 in 2012 on the TROPOS and thus a total of $126,677 for 2012 on this project.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
48a –Required WET Testing is being conducted as required by the NPDES permits.
48b –A SWPPP required for PFM was developed internally by FPL rather than using a consultant as anticipated.
48c –TROPOS has been submitted to FDEP for final approval. Work required by the plan is expected to commence in the latter part of 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project O&M expenditures for the period January 2013 through December 2013 are expected to be $113,500.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Industrial Boiler MACT Project – O & M
Project No. 48

Project Description:
40 CFR Part 63 Subpart JJJJJ Final Rule for National Emission Standards for Hazardous Air Pollutants [HAPS] for Area Sources: Industrial, Commercial, and Institutional Boilers was published in March 2011.
On March 21, 2011, EPA published notice that it intended to reconsider the major source rule, as well as the final rule establishing emissions standards for Boilers located at area sources. *See* 76 Fed. Reg. 15266. The area source rule was not stayed as the major source rule was and implementation started at the area sources based on the requirements of the final rule.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
FPL's Industrial Boiler MACT project changes included the EPA issued no action assurance letters addressing provisions of the final rule including initial tune-up requirements for existing industrial, commercial, and institutional boilers (Boilers) for both major and area sources. The assurance letters will remain in effect until the earlier of (1) October 1, 2012 or (2) the effective date of any final rule on reconsideration of the Boiler NESHAP. Required testing (tuning) for the industrial boilers at the FPL area sources were conducted in the July – December 2012 period (August 7,2012).

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $40,453 or 97.6% lower than originally projected. The variance is due to changes that were made to the implementation of the final rules which occurred after Commission approval of FPL's Industrial Boiler MACT project. On February 7, 2012, EPA issued no action assurance letters which granted extensions for boilers at area sources until the earlier of October 1, 2012 or a final rule on the reconsideration of the Industrial Boiler MACT. Additionally, EPA proposed reconsideration for area source boilers which would provide an additional year to comply with the testing requirements. FPL anticipates lower than originally projected costs for combustion tuning with required testing for its industrial boilers at area sources, which will be conducted in the July – December 2012 period following previously scheduled unit maintenance outages.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The one time Energy Assessments are due within 3-years of the rule effective date. An appropriate energy assessor will be contracted to complete energy assessments in early 2013 for two process heaters.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures for the period January 2013 through December 2013 are expected to be $1,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Thermal Discharge Standards Project – O & M
Project No. 49

Project Description:
FPL power plants with once-through cooling water systems that were built before July 1, 1972, must meet a "narrative" thermal standard found in Chapter 62-302.520(1) (a)-(c) F.A.C. This rule is implemented through the National Pollutant Discharge Elimination System (NPDES) program. See 33 U.S.C. Section 1342. Pursuant to the U.S. Environmental Protection Agency's (EPA) approval, the Florida Department of Environmental Protection (FDEP) implements the NPDES permitting program in Florida. Affected facilities are required to apply for renewal of the 5-year-duration NPDES permits prior to their expiration.

Facilities that cannot meet the FDEP narrative standard for thermal discharges may apply for a "variance" (i.e. less stringent standards) under Section 316(a) of the Federal Clean Water Act. Section 316(a) ensures that thermal effluent limitations will assure protection and propagation of balanced, indigenous population of shellfish, fish, and wildlife and provides that thermal dischargers can be granted less stringent alternate thermal limits than those imposed by a state program if the discharger can demonstrate that the current effluent limitations, based on water quality standards, are more stringent than necessary to protect the aquatic organisms in the receiving water body.

Prior to 2008, 316(a) variance determinations were conducted using guidance from the EPA that was developed in 1977. If a variance from the state water quality standard for temperature was previously granted, facilities were not required to provide additional information regarding thermal discharges in their renewal application unless changes had been made to the thermal loading in the plant discharge. In 2008, the EPA issued additional guidance on this topic and, with the new guidance; the EPA has taken a much more active role in granting variances resulting in requests for expanded biological and thermal modeling/monitoring studies to justify the variances.

In addition, many plants that have once-through cooling water systems that discharge heated effluent and were originally deemed compliant with Chapter 62-302.520 (1) (a) (c) have been under scrutiny by the FDEP. Oversight of these facilities is also implemented via the NPDES permitting process. During recent permit renewals, the FDEP, much like the EPA with the 316(a) variances, has taken a more stringent approach to the required demonstration that substantial damage to aquatic organisms is not occurring in the receiving water bodies.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Reconnaissance sampling, as well as some baseline sampling, as required by the PCC NPDES permit, was begun in early 2012. However, FPL is only seeking recovery for work conducted after it files its petition for Commission approval of the project. Work required by the PRV NPDES permit, which consists mainly of Plan of Study development, will begin after filing for Commission approval of the project.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $175,000.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
FPL has begun basic reconnaissance sampling and has submitted the PCC thermal plan of study to the FDEP for final approval. Required background sampling will continue in 2012 as well as negotiations with FDEP and EPA Region 4 to obtain approval for the Plan of Study that was submitted to FDEP and EPA Region 4, previously. FPL will be submitting a proposed Plan of Study for PRV to FDEP by December 2012, as required by the NPDES permit (i.e. 18 months prior to commercial operation).

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project O&M expenditures for the period January 2013 through December 2013 are expected to be $175,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Steam Electric Guidelines Revised Rule - O & M**
Project No. 50

Project Description:
Title 40 Code of Federal Regulations Part 423, which was promulgated under the authority of the Federal Clean Water Act, limits the discharge of pollutants into navigable waters and into publicly owned treatment works by existing and new sources of steam electric power plants. The current version of the rule was published in the Federal Register on November 19, 1982. On September 15, 2009, the EPA announced that they would undertake rulemaking to revise the rule because, "current regulations, which were issued in 1982, have not kept pace with changes that have occurred in the electric power industry over the last three decades." In early April 2012, EPA announced that a draft rule will be signed by November 20, 2012, with a final rule expected by April 28, 2014.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
FPL will be conducting extensive sampling and chemical analyses of the Manatee Plant oil ash and metal cleaning waste effluent streams in 2012. However, FPL is only seeking recovery for work conducted after it files its petition for Commission approval of the project.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project expenditures are estimated to be $5,000.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
FPL will be conducting extensive sampling and chemical analyses of the Manatee Plant oil ash and metal cleaning waste effluent streams in August 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project O&M expenditures for the period January 2013 through December 2013 are expected to be $45,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Gopher Tortoise Relocation Project – O&M
Project No. 51

Project Description:
The Gopher tortoise (Gopherus polyphemus) is a state-designated threatened species, per Rule 68A-27.003(1)(d)3, F.A.C. Gopher tortoises have been creating burrows in the cooling pond embankments at FPL's Martin (PMR), Manatee (PMT) and Sanford (PSN) power plants over time, as well as in the oil tank farm embankments at PMR and PMT. Gopher tortoise burrows must be inspected and then filled as necessary to ensure the integrity of the embankments. Filling burrows means that affected gopher tortoises must be relocated. In 2008, the Florida Fish and Wildlife Conservation Commission provided new gopher tortoise guidelines that have changed the permitting process for relocations (i.e., an authorized gopher tortoise agent is now required to conduct surveys and perform relocations and all tortoises now must be sent to a recipient site).

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
As part of normal plant maintenance, FPL conducts periodic surveys at all three sites to ensure that the integrity of the embankments is maintained. In March 2012, surveys were conducted that found gopher tortoise burrows at PMT that could compromise the embankments' integrity. In order to fill the burrows at PMT, the gopher tortoises need to be relocated by an authorized gopher tortoise agent.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
There has been no cost to date. However, FPL projects that it will begin incurring costs for gopher tortoise relocations in September 2012. FPL's O&M cost estimate for the relocations at PMT is $37,500 in 2012.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
FPL will be applying for the permit and plans on relocating the tortoises in September of 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
As part of normal plant maintenance, FPL conducts periodic surveys at all three sites to ensure that the integrity of the embankments is maintained. FPL cannot predict at this time the costs that it will incur for this project beyond 2012. However, at this time we estimate that $37,500 of O&M will be spent for all three sites in 2013.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Numeric Nutrient Criteria – O&M**
Project No. 52

Project Description:
The EPA is under a federal court order to implement numeric nutrient criteria (NNC) through NPDES permit renewals for the reduction of total nitrogen and total phosphorus discharges and load in Florida freshwaters to comply with the Federal Clean Water Act. The FDEP has drafted its own NNC rule and has strongly communicated to the EPA that it prefers to implement the state rule. The EPA supports the FDEP in that effort. The EPA has until the January 6, 2013 implementation date to review and approve the FDEP's proposed NNC rule. Either the EPA or FDEP numeric nutrient criteria rule will be implemented through NPDES Industrial Waste Water permit renewals for the reduction of total nitrogen (TN) and total phosphorus (TP) discharges and loading in Florida freshwaters.

FPL does not anticipate incurring costs for the project in 2012. For 2013, FPL projects to spend $0.442 million for O&M. The O&M activities include monthly water sampling (intake and discharge structures) and reporting, biological assessments (stream condition index assessment upstream and downstream of the discharges) and reporting, and changes to water chemistry. FPL plants that will be subject to the flowing streams (freshwater) numeric nutrient criteria are Ft. Myers, Manatee, Martin, Putnam, and Sanford.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The EPA has not implemented their rule or approved the FDEP rule to date.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
None.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
A contractor proposal has been received for the development and execution of water (TN and TP) and biological (Stream Condition Index) sampling at the intake and outfall structures at PFM, PPN, PMT, PMR, and PSN.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project O&M expenditures for the period January 2013 through December 2013 are expected to be $442,400.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Low NOx Burner Technology – Capital**
Project No. 2

Project Description:
Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce NOx emissions by implementing Reasonably Available Control Technology (RACT). The Dade, Broward and Palm Beach county areas were classified as "moderate non-attainment" by the State of Florida and the EPA. FPL has six units in this affected area that require implementation of RACT for NOx emission reductions.

The Florida DEP designated Low NOx Burner Technology (LNBT) as RACT determining that it meets the requirement to reduce NOx emissions. Reductions are achieved by delaying the mixing of the fuel and air at the burner, creating a staged combustion process along the length of the flame. NOx formation is reduced because peak flame temperatures and availability of oxygen for combustion is reduced in the initial stages.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
All six units are in service and operational.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Dade, Broward and Palm Beach Counties have now been re-designated as "attainment" for ozone with air quality maintenance plans. This re-designation still requires that all controls, such as LNBT, placed in effect during the "non-attainment" be maintained. The LNBT burners are installed at all of the six units and design enhancements are complete.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $177,872.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Continuous Emission Monitoring System (CEMS) – Capital**
Project No. 3b

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO2, NOx, CO, Carbon Dioxide (CO2/O2) emissions, as well as opacity data from affected air pollution sources. FPL has 57 units, which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants and opacity. These Systems continuously extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability. Operation and maintenance of these systems in accordance with the provisions of 40 CFR Part 75 is an ongoing activity, which follow the Title IV CEMS Quality Assurance Program Manual.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
This is an ongoing project. No new additions to plants for 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $40,331 or 5.8% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
No new activity for 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $518,983.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Clean Closure Equivalency – Capital**
Project No. 4b

Project Description:
In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed Coeds for nine FPL power plants to demonstrate to the U.S. EPA that no hazardous waste or hazardous constituents remain in the soil or water beneath the basins which had been used in the past to treat corrosive hazardous waste. The basins, which are still operational as part of the wastewater treatment systems at these plants, are no longer used to treat hazardous waste.

To demonstrate clean closure, soil sampling and ground water monitoring plans, implementation schedules, and related reports must be submitted to the EPA. Capital costs are for the installation of monitoring wells (typically four per site) necessary to collect ground water samples for analysis.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
All activities are complete.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $1,270.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital
Project No. 5b

Project Description:
Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The Port Everglades Tank 904 liner replacement project was initiated in 2011 and completed in March, 2012. This project was required because the existing tank liner system (Delta Liner) failed. PPE Tank 903 has a similar Delta Liner system but has no indications of leaking at this time. This tank has the last Delta Liner in the FPL fleet and we are planning to replace that liner during the scheduled for API-653 internal inspection in 2016. If Tank 903 liner fails, we will have to accelerate the inspection and replacement at that time.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $14,277 or 1.4% higher than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The Port Everglades Tank 904 liner replacement project was initiated in 2011 and completed in March, 2012. No other capital tank work is planned until 2016.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $907,131.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Relocate Turbine Lube Oil Underground Piping to Above Ground – Capital**
Project No. 7

Project Description:
In accordance with criteria contained in Chapter 62-762 of the Florida Administrative Code (F.A.C.) for storage of pollutants, FPL initiated the replacement of underground Turbine Lube Oil piping to above ground installations at the St. Lucie Nuclear Power Plant.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
This project is complete.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $1,447.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Oil Spill Cleanup/Response Equipment – Capital**
Project No. 8b

Project Description:
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments
(January 1, 2012 to December 31, 2012)
All equipment is being maintained and replaced as necessary to maintain compliance with regulatory guidelines for response readiness. In 2012, we intend to purchase two (2) boom reel trailers as well as to install two (2) fixed boom reels at Fort Myers Plant and Lauderdale Plant by end of the year.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $49,169 or 34.8% higher than originally projected. The variance is primarily due to charges related to the Discharge Canal and Intake Canal Oil Spill Hard Booms at the Port Everglades plant that were inadvertently charged to the SPCC-Spill Prevention, Control & Countermeasures project in June 2011. These costs were reclassified to this project in March 2012.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
All deadlines, both state and federal, have been met. Ongoing costs will be annual in nature and will consist of equipment upgrades/replacements.

Project Projections
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $159,618.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Relocate Storm Water Runoff – Capital**
Project No. 10

Project Description:
The new National Pollutant Discharge Elimination System (NPDES) permit, Permit No. FL0002206 for the St. Lucie plant, issued by the United States Environmental Protection Agency contains new effluent discharge limitations for industrial-related storm water from the paint and land utilization building areas. The new requirements became effective on January 1, 1994. As a result of these new requirements, the affected areas will be surveyed, graded, excavated and paved as necessary to clean and redirect the storm water runoff. The storm water runoff will be collected and discharged to existing water catch basins on site.

Project Accomplishments:
(January 1, 2012 December 31, 2012)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2012 December 31, 2012)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 December 31, 2012)
All activities are complete.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $7,846.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Scherer Discharge Pipeline- Capital**
Project No. 12

Project Description:
On March 16, 1992, pursuant to the provisions of the Georgia Water Control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated there under the Georgia Department of Natural Resources issued the National Pollutant Discharge Elimination System (NPDES) permit for Plant Scherer to Georgia Power Company. In addition to the permit, the department issued Administrative Order EPD-WQ-1855, which provided a schedule for compliance by April 1, 1994 with the new facility discharge limitations to Berry Creek. As a result of these new limitations, and pursuant to the order, Georgia Power Company was required to construct an alternate outfall to redirect certain wastewater discharges to the Ocmulgee River. Pursuant to the ownership agreement with Georgia Power Company for Scherer Unit 4, FPL is required to pay for its share of construction of the discharge pipeline, which will constitute the alternate outfall.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
All activities are complete.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $52,573.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Wastewater Discharge Elimination & Reuse – Capital**
Project No. 20

Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants, and the Dade County DERM requires the Turkey Point and Cutler plants' wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $420 or 0.3% higher than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
All activities are complete.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $84,240.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **St. Lucie Turtle Net – Capital**
Project No. 21

Project Description:
FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service ("NMFS"). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years. An effective 5-inch primary barrier net is vital to limiting the number of lethal turtle takes per year. In 2002, the existing net became deformed due to the influxes of jellyfish and algae entering the canal. With the Commission approval, a replacement and enhancement of the net system was performed. In 2007, the antifoulant and protective coating on the existing 5-inch net deteriorated and was experiencing UV damage. With Commission approval, FPL purchased and installed a new 5-inch net in 2009.

In October 2009, the 5-inch primary barrier net failed due to influxes of algae that entered the canal and created a blockage of approximately 80% of the net. The net is currently in a temporary configuration, which has created an effective temporary barrier for turtles. The Turtle Net project now requires the engineering, construction and installation of a more robust barrier structure that can withstand significant algal events and similar environmental challenges. The proposed design would include the removal of the damaged piles and installation of new piles and a support structure to effectively secure the net.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Engineers have proposed and are currently designing a more effective barrier structure that will include a method for tensioning the turtle net and the design of a portable lift station. Engineering is also working on a design to improve the debris handling capability of the structure in order to provide improved access for maintenance of the net.

Project Fiscal Expenditures:
(January 1, 2012 – December 31, 2012)
Project depreciation and return on investment are estimated to be $9,483 or 8.1% lower than originally projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Engineering vendor was selected and drawings are to be received by fourth quarter of 2012. Site certification approval process expected to commence during the fourth quarter of 2012. The current net will remain in a temporary configuration until the new structure is constructed. Engineering of the structure will continue through 2012. Construction activities on the net planned expected to begin first quarter 2013.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $120,414.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Pipeline Integrity Management (PIM) – Capital**
Project No. 22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid / gas pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
A pipeline leak detection system for the TMR-30 Pipeline was engineered and major elements purchased during the 2011 calendar year. Its installation and commission was completed and the system placed in service June 2012. Additionally, a pipeline leak detection system for the TMT-16 Pipeline is being designed with installation planned for 4Q12.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $132 or 0.1% higher than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Leak detection systems on pipeline are operational on TMR-30 and TMR-18 Pipelines. Addition of leak detection system on TMT-16 is expected to be completed 4Q12. These systems allow us to closely monitor pipeline delivery operations and provide for safe shutdown of the transfers if a leak is detected and confirmed. These leak detection systems are a pro-active element of our Pipeline Integrity Management program.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $342,928.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (Spill Prevention, Control, and Countermeasures) – Capital
Project No. 23

Project Description:
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- Has a combined aboveground oil storage capacity of more than 1320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and

- Due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

  In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002. A deficiency was found at the St, Lucie Unit 2 Diesel Oil Storage Tank and refueling tank areas. In order to meet compliance regulations, these areas are required to have secondary containment systems installed. For compliance, it is necessary to install oil berms, designed to catch any spilled oil upon delivery, in these areas.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
FPL is begun demolishing an aboveground oil water separator at the Sanford Plant, July 30, 2012. Construction will include a new oil waster separator and two associated pumps. Project projected completion date September 1, 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $23,395 or 1.2% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
FPL began demolishing an aboveground oil water separator at the Sanford Plant, July 30, 2012. Construction will include a new oil waster separator and two associated pumps. Project projected completion date September 1, 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $1,562,026.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Manatee Reburn – Capital**
Project No. 24

Project Description:
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process is shown conceptually in Figure 1 (see below), and divides the furnace into three zones.

In the 1996-97 time periods, FPL invested a considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, and pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Installation of the Unit 1 and Unit 2 equipment is complete, started up and completed process optimization of the new systems to ensure minimal emissions. Both units are out of warranty. New permit limits have been accepted by the FDEP. The project is continuing to incur on-going operating and maintenance costs.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $11,463 or 0.3% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Unit 1 and 2 both completed.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $3,130,961.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Pt. Everglades ESP (Electrostatic Percipitators) Technology – Capital**
Project No. 25

Project Description:
The requirements of the Clean Air Act direct the Environmental Protection Agency to develop health-based standards for certain "criteria pollutants". i.e. ozone (O3), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The original Port Everglades Title V permit, issued in 1998, expired in 2003. The renewal permit issued January 1, 2004 expired on December 31, 2008. A renewal permit application has been submitted and is pending DEP review. The DEP's Title V permit for FPL Port Everglades plant requires FPL to install and maintain Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
No Power Generation plant additions occurred.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
At this time, all four ESPs (Units 1 through 4) have construction activities completed and are operational. The Units 1-4 precipitators met all performance guarantees and permit requirements. The Units 1-4 stack emissions were well below the new Title V permit requirements of .03 lb/mmbtu particulate and 20% opacity. Enclosure of ash truck loading bay is completed to contain fugitive airborne ash during truck loadings.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $21,326,855.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **UST Replacement/Removal – Capital**
Project No. 26

Project Description:
The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.

UST Category-B tanks are tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have a secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST shall have secondary containment if installed after December 10, 1990.

UST and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
There were no activities in 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $474 or 3.9% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $10,909.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **CAIR Compliance – Capital**
Project No. 31

Project Description:
In response to the EPA Clean Air Interstate Rule (CAIR), FPL initiated the CAIR Project to implement strategies to comply with Annual and Ozone Season NOx and SO2 emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, the costs for the operation of SCR's constructed on SJRPP Units 1 and 2, costs for the operation of the Scrubber and SCR being installed on Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in a cycling mode. The study costs to Aptech Engineering have been paid and a significant portion of the work has been completed on the Martin and Manatee 800 MW units. Several countermeasures were prioritized and scheduled for implementation in 2008 – 2011. The CEMS installation on the Gas Turbine Peaking Units has been completed with ongoing maintenance expenses for their operation. On December 3, 2008 Georgia EPD promulgated the GA Multi-Pollutant rule requiring installation of SCR and a Scrubber on Scherer Unit 4. Recently, on July 6, 2010, EPA proposed the Transport Rule, which will leave requirements to comply with the CAIR regulations in place until 2012 when a new program will be implemented to further reduce So2 and NOx emissions from fossil power plants.

Project Accomplishments:
(January. 1, 2012 to December 31, 2012)
800MW Cycling - Completed the implementation of the major 800MW cycling countermeasures for Manatee Unit 1 and Martin Unit 2 during the first half of 2010. Construction efforts remain in progress to complete the remaining Superheat Spray, Extraction and Turbine.

SJRPP 1&2 SCR's are now in operation and construction was completed on the Scherer FGD and SCR in May 2012. Performance guarantee testing of the SCR was completed in June 2012 and it is now in operation. Performance guarantee testing of the FGD is projected to be completed in August 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $3,623,938 or 6.1% lower than previously projected. The variance is primarily due to a shift in Scherer Unit 4 FGD costs from 2012 to 2013. Additionally, Scherer Unit 4 SCR equipment and contingency costs were lower than originally projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Completed the implementation of the major 800MW cycling countermeasures for Manatee Unit 1 and Martin Unit 2 during the first half of 2010. Construction efforts remain in progress to complete the remaining Superheat Spray, Extraction and Turbine Water Induction Prevention countermeasures for Martin Unit 1 by the end of the year. Completion of the Superheat Spray and Extraction countermeasures at Manatee Unit 2 along with Rotor Stress are scheduled for 2011.

FPL's CAIR project at SJRPP U1 & 2 continues with both SCR's in operation. Installation of Scrubbers and SCR's at plant Scherer for compliance with CAIR was completed with the SCR now in operation and the FGD projected to complete performance guarantee testing in August 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $59,839,942.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **MATS Project – Capital**
Project No. 33

Project Description:
The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on March 15, 2005, imposing nation-wide standards of performance for mercury (Hg) emissions from existing and new coal-fired electric utility steam generating units. The CAMR is designed to reduce emissions of Hg through implementation of coal-fired generating unit Hg controls. In addition, CAMR requires the installation of Hg Continuous Emission Monitoring Systems (HgCEMS) to monitor compliance with the emission requirements. The rule is implemented in two phases with an initial compliance date of 2010 for Phase I and the final required reductions of Phase II in 2018. The State of Florida has begun the implementation of the requirements for reduction of Hg through rule making process. Plant St. John's River Power Park (SJRPP) Units 1 & 2, in which FPL has 20% ownership shares, are affected units under this rule and will require the installation of Hg controls and HgCEMS. Similarly, the State of Georgia has also begun their rule making process to implement the federal rule, which will affect FPL's ownership share of Plant Scherer Unit 4, also requiring the installation of HgCEMS and Hg controls.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The Scherer Unit 4 baghouse was placed into service April 4, 2010 meeting the GA Multi-Pollutant Rule requirements. The baghouse passed all performance guarantee tests in May 2010 and is now in continuous operation.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return are estimated to be $44,519 or 0.4% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The Scherer Unit 4 baghouse was placed into service April 4, 2010. The baghouse passed all performance guarantee tests in May 2010.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $12,011,159.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **St. Lucie Cooling Water System Inspection and Maintenance – Capital**
Project No. 34

Project Description:
The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system (the "Cooling System") at FPL's St. Lucie nuclear plant , such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie Plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie Plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion ("BO") that is to be issued by the National Oceanic and Atmospheric Administration ("NOAA") pursuant to section 7 of the ESA. It is anticipated that NOAA will finalize the BO in late 2012 or early 2013. NOAA sent the Nuclear Regulatory Commission ("NRC") a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes.

Project Accomplishments:
(January 1, 2012 thru December 31, 2012)
Preliminary turtle excluder design documents (drawings and calculations) were completed in the spring of 2010. No work on the turtle excluder design package and testing will be performed until we receive the issuance of the Biological Opinion.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance in the project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The turtle excluder design package documents (drawings and calculations) were started in the spring of 2009. Preliminary design documents were completed in spring of 2010. Flow meters to be installed in 2011. Final documents and testing anticipated to be completed in 2013.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are $17,946.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Drinking Water System Compliance – Capital**
Project No. 35

Project Description:
The Martin Drinking Water System (DWS) is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for TTHM (trihalomethanes) and HAA5 (Haleo Acetic Acid). The upgrades to the potable water system will cause FPL to incur capital costs for major component upgrades to the system in order to comply with the new requirements. These include Nano filtration, air stripping, carbon and multimedia filtration. The operation of the potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The system is in service in 2008 and operating as designed.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance in the project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The installation was approved by FDEP, the capital installation was completed in 2008 and the system is in service.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for the period January 2013 through December 2013 are $24,932.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Low Level Radioactive Waste - Capital**
Project No. 36

Project Description:
The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste (LLW) such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. The Barnwell facility ceased accepting LLW from FPL June 30th, 2008. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN is to ensure construction of a LLW storage facility with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5 year period. This will allow continued uninterrupted operation of the PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN will also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The Turkey Point LLW Storage Facility project schedule has been created. The Engineering Package has been completed and issued for construction. A contractor has been selected and contracts are in the process of being created. The construction of the LLW Storage Facility at Turkey Point is planned to commence in September of 2012 and is expected to be completed by September of 2013.

The St. Lucie LLW Storage Facility has been placed on hold in 2012 as a result of resources being dedicated to other projects. Completion of the Facility will resume in January of 2013 with the installation of the fiber optics for the fire detection system, installation of the internal shielding, and the crane rails for the gantry crane.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $581,545 or 44.6% lower than previously projected. The variance is primarily due to a change in the in-service date from March 2012 to December 2013 due to the Turkey Point Unit 3 and Unit 4 EPU outages.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The construction of the LLW Storage Facility at Turkey Point is planned to commence in September of 2012 and is expected to be completed by September of 2013.

The LLW Project at St. Lucie has experienced some additional schedule delays due to the competition for resources being focused on other projects. This has resulted in delaying the completion of the facility to the 1st quarter 2013. The St. Lucie LLW schedule delay has shifted some of the projected 2010 expenditures for the construction work into 2011 and 2013.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are $744,133.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **DeSoto Next Generation Solar Energy Center – Capital**
Project No. 37

Project Description:
The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic generating facility which will convert sunlight directly into electric power. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility will utilize cutting edge solar panel technology. The project will involve the installation of the solar PV panels and tracking system and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Desoto Next Generation Solar Energy Center achieved Commercial Operation on October 27, 2009. All Engineering and Construction "punch list" items have been completed and Final Acceptance was achieved on April 27, 2010. During Q4 2011 an uninterruptible power supply for each inverter container was installed and software modifications were made to provide Low Voltage Ride Through capability which was a requirement to fully satisfy the plant interconnection requirements with the transmission system.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return were $103,004 or 0.6% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Desoto achieved Commercial Operation on October 27, 2009 and Final Acceptance on April 27, 2010. No plant additions are projected this year.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are expected to be $16,630,525.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Space Coast Next Generation Solar Energy Center – Capital**
Project No. 38

Project Description:
The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW solar photovoltaic (PV) generating facility which will convert sunlight directly into electric power. The facility will utilize a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project will involve the installation of the solar PV panels and support structures and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

The Space Coast project also includes building a 900 KW solar PV facility at the Kennedy Space Center (KSC) industrial area. This 900 KW solar site will be built and operated and maintained by FPL as compensation for the lease of the land for the Space Coast Solar Site which is located on KSC property.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Space Coast Solar Site achieved commercial operation on April 16, 2010 and Final Acceptance occurred on October 13, 2010. No plant additions are projected this year.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return were $50 or 0.0% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Space Coast Solar Site achieved commercial operation on April 16, 2010 and Final Acceptance occurred on October 13, 2010. No plant additions are projected this year.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are $7,890,598.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Next Generation Solar Energy Center – Capital**
Project No. 39

Project Description:
The Martin Next Generation Solar Energy Center ("Martin Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam to be supplied by Martin Solar will be used to supplement the steam currently generated by the heat recovery steam generators. The project will involve the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors will track the sun to maintain the optimum angle to collect solar radiation. The collectors will concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Commercial Operation of Martin Solar occurred on December 10, 2010. Five (5) plant addition scopes are in progress of completion by year end 2012.

1. Cold Reheat system additions – work on B & C trains are complete; A & D trains are projected to be complete in August 2012.
2. Heat Transfer Fluid Overflow prevention and containment – work is scheduled to begin during Q3 2012.
3. Dust Suppression and Road Paving – this work scope is projected to be complete in August 2012
4. Feedwater Recirculation – design and analysis has been completed based upon the current performance conditions; no further activity is currently scheduled.
5. Auxiliary Sky Vents additions – B & C trains are complete; A & D trains are projected to be complete in August 2012.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return were $432,621 or 0.9% higher than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Commercial Operation of Martin Solar occurred on December 10, 2010. Several plant addition scopes are in progress and scheduled for completion by year end 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are expected to be $47,298,902.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Manatee Temporary Heating System Project – Capital**
Project No. 41

Project Description:
FPL is subject to specific and continuing legal requirements to provide a warm water refuge for endangered manatees at its Riviera (PRV), Cape Canaveral (PCC) and Port Everglades (PPE) Plants. FPL has undertaken the design, engineering, purchase, and installation of a temporary manatee heating system at PRV, PCC, and PPE ("the Project"). The Project is required pursuant to PRV's, PCC's, and PPE's Manatee Protection Plans (MPP), as part of the State Industrial Wastewater Facility Permit Numbers FL0001546, Specific Condition 13, issued on February 16, 1998, FL0001473, Specific Condition 9, issued on August 10,2005, and FL0001538, Specific Condition 10, issued on July 22, 2010 respectively. In order to comply with the respective MPP's; FPL's installation of a temporary manatee heating system at PRV, PCC, and PPE will be implemented to avoid potential adverse impacts to manatees congregating at PRV's, PCC's, and PPE's manatee embayment area. Manatees currently gather at the plants during the annual period from November 15 to March 31 at PRV and PPE and the annual period of October 15 to March 31 at PCC. FPL's installation of the Manatee Temporary Heating System at each site must be implemented to provide warm water until the site has completed the planned modernization of the existing power generation units and return of warm water flow from the generating unit cooling water will be provided by operation of the new units.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The Manatee Temporary Heating System at PRV began operations in Q4 2009 and was available throughout the 2009 – 2012 manatee seasons. The PCC Manatee Temporary Heating System work was completed in September 2010 and the unit was available throughout the 2010 – 2012 manatee seasons. The PPE Manatee Temporary Heating System is scheduled to be operational and available January 2013 when the existing Port Everglades Units 1-4 shutdown.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $42,470 or 4.5% lower than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The PPE Manatee Temporary Hearting System is scheduled to be operational in Q4 2012.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are expected to be $1,270,783.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Turkey Point Cooling Canal Monitoring Plan – Capital**
Project No. 42

Project Description:
Pursuant to Conditions IX and X of the Florida Department of Environmental Protection's (FDEP) Final Order Approving Site Certification, filed October 29, 2008, FPL submitted its initial draft of the proposed Cooling Canal Monitoring Plan associated with FPL's Turkey Point Uprate Project to the South Florida Water Management District (SFWMD). This plan requires an assessment of baseline conditions to provide information on the vertical and horizontal extent of the hypersaline groundwater plume and effect of that plume on ground and surface water quality, if any. Comments, concerns and requests for revisions or action items were received from the SFWMD as well as the FDEP. Miami-Dade Department of Environmental Resource Management (DERM) has incorporated into the current draft the proposed monitoring plan, dated July 16, 2009.

The TP CCM Plan was finalized by FPL and the agencies on October 14, 2009. The objective of FPL's TP CCM Plan is to implement the Conditions of Certification IX and X, which states that "the Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to surface water, groundwater and water quality monitoring, and ecological monitoring to: delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition; determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate Project. The Revised Plan includes installation and monitoring of an appropriate network of wells and surface water stations.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
The wells and monitoring equipment were installed in 2010 for the Cooling Canals at Turkey Point plant, which included probes, telemetry, solar panels and associated platforms to support the monitoring equipment.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance in the Project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Drilling, construction of wells and equipment installation was completed in 2010.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are expected to be $383,311.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Barley Barber Swamp Iron Mitigation Project – Capital**
Project No. 44

Project Description:
Engineer and install a siphon and a new discharge system to turn the existing flow away from the Barley Barber Swamp and back into the Martin Plant Cooling Pond.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
A new siphon and discharge system was engineered and installed. The system has been placed into service.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
Project depreciation and return on investment are estimated to be $1,974 or 11.6% higher than previously projected.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
The project installation was engineered and installed. The capital project is in service.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are expected to be $18,168.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **800MW Unit ESP Project – Capital**
Project No. 45

Project Description:
On December 21, 2011, Environmental Protection Agency issued the final Maximum Achievable Control Technology (MACT) rule, which has the effect of requiring ESPs for the 800 MW oil-fired units. Specifically, the final MACT rule established numerical emission limits for particulate material (PM) as a surrogate for all toxic metals, along with emission limits for acid gasses (hydrochloric and hydrofluoric acids). The numerical particulate emission limits require that FPL install particulate emission control devices on its Martin and Manatee 800 MW oil-fired units in order to retain its flexibility regarding the operation of those units on oil. ESPs are the most cost-effective form of particulate emission control for the 800 MW oil-fired units. As to the final MACT rule's limits on acid gasses, FPL has the compliance option of limiting the moisture content of the oil it burns in those units. To comply, FPL will install Electrostatic Precipitators on Manatee Units 1 and 2 and Martin Units 1 and 2.

Project Accomplishments:
(January 1, 2012 to December 31, 2012)
Work on Manatee Unit 2 commenced on October 3, 2011 and Mechanical completion was accomplished on June 12, 2012. The provisional acceptance was achieved on July 13, 2012. Manatee Unit 1 outage is scheduled to begin September 2, 2012 with Mechanical completion projected for June 2013.

Project Fiscal Expenditures:
(January 1, 2012 to December 31, 2012)
The variance of $6,171,976 is due to project depreciation and return on investment that were not included in the original 2012 projections because the final MATS rule had not yet been issued.

On December 21, 2011, EPA issued the final MATS rule, which has the effect of requiring ESPs for the 800 MW oil-fired units. Consistent with the stipulation in Order No. 11-0083-FOF-EI, FPL transferred the construction costs for the Manatee Unit 2 ESP, together with accumulated AFUDC, to ECRC-recoverable accounts as part of its January 2012 accounting entries.

Project Progress Summary:
(January 1, 2012 to December 31, 2012)
Work on Manatee Unit 2 commenced on October 3, 2011 and Mechanical completion was accomplished on June 12, 2012. The provisional acceptance was achieved on July 13, 2012. Manatee Unit 1 outage is scheduled to begin September 2, 2012 with Mechanical completion projected for June 2013.

Project Projections:
(January 1, 2013 to December 31, 2013)
Estimated project fiscal expenditures (depreciation and return) for January 2013 through December 2013 are expected to be $12,603,853.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ENERGY DEMAND ALLOCATION % BY RATE CLASS

FORM: 42-6P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
RATE CLASS	Avg 12 CP Load Factor at Meter (%) [a]	GCP Load Factor at Meter (%) [b]	Projected Sales at Meter (KWH) [c]	Projected Avg 12 CP at Meter (KW) [d]	Projected GCP at Meter (KW) [e]	Demand Loss Expansion Factor [f]	Energy Loss Expansion Factor [g]	Projected Sales at Generation (KWH) [h]	Projected Avg 12 CP at Generation (kW) [i]	Projected GCP Demand at Generation (kW) [j]	Percentage of KWH Sales at Generation (%) [k]	Percentage of 12 CP Demand at Generation (%) [l]	Percentage of GCP Demand at Generation (%) [m]
RS1/RST1	61.443%	58.164%	53,023,166,899	9,851,224	10,406,586	1.07934640	1.06237778	56,330,634,339	10,632,883	11,232,312	51.45044%	58.40675%	55.76814%
GS1/GST1/WIES1	76.122%	63.338%	5,844,824,242	876,512	1,053,416	1.07934640	1.06237778	6,209,411,403	946,060	1,137,000	5.67146%	5.19674%	5.64518%
GSD1/GSDT1/HLFT1	78.359%	69.534%	25,078,522,608	3,653,482	4,117,186	1.07921924	1.06227781	26,640,358,074	3,942,908	4,443,346	24.33238%	21.65851%	22.06110%
OS2	72.864%	15.876%	12,578,957	1,971	9,045	1.06664274	1.02956173	12,950,813	2,102	9,647	0.01183%	0.01155%	0.04790%
GSLD1/GSLDT1/CS1/CST1/HLFT2	81.031%	66.749%	11,310,651,252	1,593,418	1,934,367	1.07776257	1.06120242	12,002,890,480	1,717,326	2,084,789	10.96302%	9.43333%	10.35092%
GSLD2/GSLDT2/CS2/CST2/HLFT3	93.875%	81.465%	2,450,692,797	298,011	343,410	1.06537601	1.05091974	2,575,481,437	317,494	365,861	2.35236%	1.74400%	1.81649%
GSLD3/GSLDT3/CS3/CST3	103.341%	76.256%	199,482,765	22,036	29,862	1.02320090	1.01902664	203,278,252	22,547	30,555	0.18567%	0.12385%	0.15171%
SST1T	80.153%	35.887%	97,610,914	13,902	31,050	1.02320090	1.01902664	99,468,122	14,225	31,770	0.09085%	0.07814%	0.15774%
SST1D1/SST1D2/SST1D3	67.698%	40.071%	7,613,528	1,284	2,169	1.03677940	1.02956173	7,838,597	1,331	2,249	0.00716%	0.00731%	0.01117%
CILC D/CILC G	93.225%	85.747%	3,039,558,994	372,200	404,659	1.06418212	1.05118900	3,195,150,979	396,089	430,631	2.91834%	2.17573%	2.13807%
CILC T	95.590%	82.386%	1,341,477,742	160,202	185,877	1.02320090	1.01902664	1,367,001,556	163,919	190,189	1.24857%	0.90041%	0.94429%
MET	79.014%	65.198%	92,698,007	13,393	16,231	1.03677940	1.02956173	95,438,320	13,886	16,827	0.08717%	0.07627%	0.08355%
OL1/SL1/PL1	305.172%	49.469%	630,970,753	23,603	145,605	1.07934640	1.06237778	670,329,308	25,476	157,158	0.61226%	0.13994%	0.78029%
SL2, GSCU1	100.650%	99.349%	70,594,840	8,007	8,112	1.07934640	1.06237778	74,998,389	8,642	8,755	0.06850%	0.04747%	0.04347%
Total			103,200,444,298	16,889,245	18,687,574			109,485,230,069	18,204,888	20,141,090	100.00000%	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2011 load research data.

[b] GCP load factor based on 2011 load research data.

[c] Projected KWH sales for the period January 2013 through December 2013.

[d] Calculated: (Col 4)/(8,760 * Col 2)

[e] Calculated: (Col 4)/8,760 * Col 3)

[f] Based on 2011 demand losses.

[g] Based on 2011 energy losses.

[h] Col 4 * Col 8

[i] Col 2 * Col 7

[j] Col 3 * Col 7

[k] Col 9 / total for Col 9

[l] Col 10 / total for Col 10

[m] Col 11 / total for Col 11

Note: There are currently no customers taking service on Schedules ISST1(D) or 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
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF ENVIRONMENTAL COST RECOVERY CLAUSE FACTORS

FORM: 42-7P

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE CLASS	Percentage of KWH Sales at Generation (%) [a]	Percentage of 12 CP Demand at Generation (%) [b]	Percentage of GCP Demand at Generation (%) [c]	Energy Related Cost ($) [d]	CP Demand Related Cost ($) [e]	GCP Demand Related Cost ($) [f]	Total Environmental Costs ($) [g]	Projected Sales at Meter (KWH) [h]	Environmental Cost Recovery Factor ($/KWH) [i]
RS1/RST1	51.45044%	58.40675%	55.76814%	27,669,936	92,746,992	907,515	121,324,444	53,023,166,899	0.00229
GS1/GST1/WIES1	5.67146%	5.19674%	5.64518%	3,050,099	8,252,157	91,864	11,394,121	5,844,824,242	0.00195
GSD1/GSDT1/HLFT1	24.33238%	21.65851%	22.06110%	13,085,899	34,392,634	359,000	47,837,534	25,078,522,608	0.00191
OS2	0.01183%	0.01155%	0.04790%	6,362	18,338	779	25,479	12,578,957	0.00203
GSLD1/GSLDT1/CS1/CST1/HLFT2	10.96302%	9.43333%	10.35092%	5,895,890	14,979,648	168,441	21,043,978	11,310,651,252	0.00186
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.35236%	1.74400%	1.81649%	1,265,092	2,769,389	29,560	4,064,040	2,450,692,797	0.00166
GSLD3/GSLDT3/CS3/CST3	0.18567%	0.12385%	0.15171%	99,851	196,672	2,469	298,992	199,482,765	0.00150
SST1T	0.09085%	0.07814%	0.15774%	48,859	124,076	2,567	175,502	97,610,914	0.00180
SST1D1/SST1D2/SST1D3	0.00716%	0.00731%	0.01117%	3,850	11,612	182	15,644	7,613,528	0.00205
CILC D/CILC G	2.91834%	2.17573%	2.13807%	1,569,477	3,454,945	34,793	5,059,215	3,039,558,994	0.00166
CILC T	1.24857%	0.90041%	0.94429%	671,479	1,429,808	15,366	2,116,653	1,341,477,742	0.00158
MET	0.08717%	0.07627%	0.08355%	46,880	121,119	1,360	169,359	92,698,007	0.00183
OL1/SL1/PL1	0.61226%	0.13994%	0.78029%	329,270	222,217	12,698	564,184	630,970,753	0.00089
SL2, GSCU1	0.06850%	0.04747%	0.04347%	36,840	75,384	707	112,931	70,594,840	0.00160
Total				53,779,784	158,794,992	1,627,300	214,202,076	103,200,444,298	0.00208

[a] From Form 42-6P, Col 12
[b] From Form 42-6P, Col 13
[c] From Form 42-6P, Col 14
[d] Total Energy $ from Form 42-1P, Line 5, Column 2
[e] Total CP Demand $ from Form 42-1P, Line 5, Column 3
[f] Total GCP Demand $ from Form 42-1P, Line 5, Column 4
[g] Col 5 + Col 6 + Col 7
[h] Projected KWH sales for the period January 2013 through December 2013.
[i] Col 8 / Col 9

Note: There are currently no customers taking service on Schedules ISST1(D) or 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
COST RECOVERY CLAUSES

Equity @ 10.00%

CAPITAL STRUCTURE AND COST RATES PER MAY 2012 EARNINGS SURVEILLANCE REPORT
ORDER NO. PSC-12-0425-PAA-EU

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	5,649,185,325	29.134%	5.23%	1.52%	1.52%
SHORT TERM DEBT	456,240,461	2.353%	1.43%	0.03%	0.03%
PREFERRED STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER DEPOSITS	499,755,277	2.577%	6.00%	0.15%	0.15%
COMMON EQUITY	9,065,636,845	46.754%	10.00%	4.68%	7.61%
DEFERRED INCOME TAX	3,716,119,664	19.165%	0.00%	0.00%	0.00%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	3,146,438	0.016%	8.17%	0.00%	0.00%
			0.00%		
TOTAL	19,390,084,010	100.00%		6.39%	9.33%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	5,649,185,325	38.39%	5.23%	2.01%	2.01%
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	9,065,636,845	61.61%	10.00%	6.16%	10.03%
TOTAL	14,714,822,170	100.00%		8.17%	12.04%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.5246%
SHORT TERM DEBT	0.0337%
CUSTOMER DEPOSITS	0.1547%
TAX CREDITS -WEIGHTED	0.0003%
TOTAL DEBT	**1.7134%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.6754%
TAX CREDITS -WEIGHTED	0.0010%
TOTAL EQUITY	**4.6764%**
TOTAL	6.3898%
PRE-TAX EQUITY	7.6132%
PRE-TAX TOTAL	9.3266%

Note:

(a) This capital structure applies only to Convertible Investment Tax Credit (C-ITC).

APPENDIX II

ENVIRONMENTAL COST RECOVERY

RRL-9 & RRL-10
DOCKET NO. 120007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-60

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 15
PARTY Florida Power & Light Co.
DESCRIPTION R.R. LaBauve (RRL-9), Chapter 62-302, FAC,
DATE Surface Water Quality Standards (FDEP Proposed)

CHAPTER 62-302
SURFACE WATER QUALITY STANDARDS

62-302.200 Definitions.

As used in this chapter:

(1) "Acute ~~T~~toxicity" shall mean a concentration greater than one-third (1/3) of the amount lethal to 50 percent of the test organisms in 96 hours (96 hr LC_{50}) for a species protective of the indigenous aquatic community for a substance not identified in paragraph 62-302.500(1)(c), F.A.C., or for mixtures of substances, including effluents.

(2) "Annual ~~A~~average ~~F~~flow" is the long-term harmonic mean flow of the receiving water, or an equivalent flow based on generally accepted scientific procedures in waters for which such a mean cannot be calculated. For waters for which flow records have been kept for at least the last three years, "long-term" shall mean the period of record. For all other waters, "long-term" shall mean three years (unless the Department finds the data from that period not representative of present flow conditions, based on evidence of land use or other changes affecting the flow) or the period of records sufficient to show a variation of flow of at least three orders of magnitude, whichever period is less. For nontidal portions of rivers and streams, the harmonic mean (Q_{hm}) shall be calculated as

$$Q_{hm} = \frac{n}{\frac{1}{Q_1} + \frac{1}{Q_2} + \frac{1}{Q_3} + \frac{1}{Q_4} + \ldots + \frac{1}{Q_n}},$$

in which each Q is an individual flow record and n is the total number of records. In lakes and reservoirs, the annual average flow shall be based on the hydraulic residence time, which shall be calculated according to generally accepted scientific procedures, using the harmonic mean flows for the inflow sources. In tidal estuaries and coastal systems or tidal portions of rivers and streams, the annual average flow shall be determined using methods described in EPA publication no. 600/6-85/002b pages 142 - 227, incorporated by reference in paragraph 62-4.246(9)(k), F.A.C., or by other generally accepted scientific procedures, using the harmonic mean flow for any freshwater inflow. If there are insufficient data to determine the harmonic mean then the harmonic mean shall be estimated by methods as set forth in the EPA publication Technical Support Document for Water Quality-Based Toxics Control (March 1991), incorporated by reference in paragraph 62-4.246(9)(d), F.A.C., or other generally accepted scientific procedures. In situations with seasonably variable effluent discharge rates, hold-and-release treatment systems, and effluent-dominated sites, annual average flow shall mean modeling techniques that calculate long-term average daily concentrations from long-term individual daily flows and concentrations in accordance with generally accepted scientific procedures.

(3) No change.

(4) "Biological Health Assessment" shall mean one of the following aquatic community-based biological evaluations: Stream Condition Index (SCI), Lake Vegetation Index (LVI), or Shannon-Weaver Diversity Index.

(5) ~~(4)~~ "Chronic ~~T~~toxicity"

(a) through (b) No change.

(6) ~~(5)~~ No change.

(7) ~~(6)~~ "Compensation ~~P~~point for ~~P~~photosynthetic ~~A~~activity" shall mean the depth at which one percent of the light intensity at the surface remains unabsorbed. The light intensities at the surface and subsurface shall be measured simultaneously by irradiance meters such as Kahlsico Underwater Irradiameter (Model No. 268 WA 310), or other device having a comparable spectral response.

(8) ~~(7)~~ No change.

(9) ~~(8)~~ "Designated ~~U~~use" shall mean the present and future most beneficial use of a body of water as designated by the Environmental Regulation Commission by means of the Classification system contained in this Chapter.

(10) ~~(9)~~ "Dissolved ~~M~~metal" shall mean the metal fraction that passes through a 0.45 micron filter.

(11) ~~(10)~~ "Effluent ~~L~~limitation" shall mean any restriction established by the Department on quantities, rates or concentrations of chemical, physical, biological or other constituents which are discharged from sources into waters of the State.

(12) ~~(11)~~ "Exceptional ~~E~~ecological ~~S~~significance" shall mean that a waterbody ~~water body~~ is a part of an ecosystem of unusual value. The exceptional significance may be in unusual species, productivity, diversity,

ecological relationships, ambient water quality, scientific or educational interest, or in other aspects of the ecosystem's setting or processes.

(13) ~~(12)~~ "Exceptional r~~R~~ecreational s~~S~~ignificance" shall mean unusual value as a resource for outdoor recreation activities. Outdoor recreation activities include, but are not limited to, fishing, boating, canoeing, water skiing, swimming, scuba diving, or nature observation. The exceptional significance may be in the intensity of present recreational usage, in an unusual quality of recreational experience, or in the potential for unusual future recreational use or experience.

(14) ~~(13)~~ "Existing u~~U~~ses" shall mean any actual beneficial use of the waterbody ~~water body~~ on or after November 28, 1975.

(15) ~~(14)~~ "IC25"or "Inhibition Concentration 25%" shall mean the concentration of toxicant that causes a 25% reduction in a biological response such as biomass, growth, fecundity, or reproduction in the test population when compared to the control population response.

(16) "Lake" shall mean, for purposes of interpreting the narrative nutrient criterion in paragraph 62-302.530(47)(b), F.A.C., a lentic fresh waterbody with a relatively long water residence time and an open water area that is free from emergent vegetation under typical hydrologic and climatic conditions. Aquatic plants, as defined in subsection 62-340.200(1), F.A.C., may be present in the open water. Lakes do not include springs, wetlands, or streams (except portions of streams that exhibit lake-like characteristics, such as long water residence time, increased width, or predominance of biological taxa typically found in non-flowing conditions).

(17) "Lake Vegetation Index (LVI)" shall mean a Biological Health Assessment that measures lake biological health in predominantly freshwaters using aquatic and wetland plants, performed and calculated using the Standard Operating Procedures for the LVI in the document titled *LVI 1000: Lake Vegetation Index Methods* (DEP-SOP-003/11 LVI 1000) and the methodology in *Sampling and Use of the Lake Vegetation Index (LVI) for Assessing Lake Plant Communities in Florida: A Primer* (DEP-SAS-002/11), both dated 10-24-11, which are incorporated by reference herein. Copies of the documents may be obtained from the Department's internet site at http://www.dep.state.fl.us/water/wqssp/swq-docs.htm or by writing to the Florida Department of Environmental Protection, Standards and Assessment Section, 2600 Blair Stone Road, MS 6511, Tallahassee, FL 32399-2400.

(18) ~~(15)~~ "Man-induced conditions which cannot be controlled or abated" shall mean conditions that have been influenced by human activities, and

(a) through (b) No change.

(c) cannot be restored or abated by physical alteration of the waterbody ~~water body~~, or there is no reasonable relationship between the economic, social and environmental costs and the benefits of restoration or physical alteration.

(19) ~~(16)~~ "Natural b~~B~~ackground" shall mean the condition of waters in the absence of man-induced alterations based on the best scientific information available to the Department. The establishment of natural background for an altered waterbody may be based upon a similar unaltered waterbody, ~~or on~~ historical pre-alteration data, paleolimnological examination of sediment cores, or examination of geology and soils. When determining natural background conditions for a lake, the lake's location and regional characteristics as described and depicted in the U.S. Environmental Protection Agency document titled Lake Regions of Florida (EPA/R-97/127, dated 1997, U.S. Environmental Protection Agency, National Health and Environmental Effects Research Laboratory, Corvallis, OR), which is incorporated by reference herein, shall also be considered. The lake regions in this document are grouped according to ambient total phosphorus and total nitrogen concentrations in the following lake zones:

(a) The TP1 phosphorus zone consists of the USEPA Lake Regions 65-03, and 65-05.

(b) The TP2 phosphorus zone consists of the USEPA Lake Regions 75-04, 75-09, 75-14, 75-15 and 75-33.

(c) The TP3 phosphorus zone consists of the USEPA Lake Regions 65-01, 65-02, 75-01, 75-03, 75-05, 75-11, 75-12, 75-16, 75-19, 75-20, 75-23, 75-24, 75-27, 75-32 and 76-03.

(d) The TP4 phosphorus zone consists of the USEPA Lake Regions 65-04, 75-02, 75-06, 75-08, 75-10, 75-13, 75-17, 75-21, 75-22, 75-26, 75-29, 75-31, 75-34, 76-01and 76-02.

(e) The TP5 phosphorus zone consists of the USEPA Lake Regions 75-18, 75-25, 75-35, 75-36 and 76-04.

(f) The TP6 phosphorus zone consists of the USEPA Lake Regions 65-06, 75-07, 75-28, 75-30 and 75-37.

(g) The TN1 phosphorus zone consists of the USEPA Lake Region 65-03.

(h) The TN2 phosphorus zone consists of the USEPA Lake Regions 65-05 and 75-04.

(i) The TN3 phosphorus zone consists of the USEPA Lake Regions 65-01, 65-02, 65-04, 75-01, 75-02, 75-03, 75-09, 75-11, 75-15, 75-20, 75-23, 75-33 and 76-03.

(j) The TN4 phosphorus zone consists of the USEPA Lake Regions 65-06, 75-05, 75-06, 75-10, 75-12, 75-13, 75-14, 75-16, 75-17, 75-18, 75-19, 75-21, 75-22, 75-24, 75-26, 75-27 and 75-29, 75-31, 75-32, 75-34 and 76-02.

(k) The TN5 phosphorus zone consists of the USEPA Lake Regions 75-07,75-08, 75-25, 75-28, 75-30, 75-35, 75-36, 75-37, 76-01 and 76-04.
The Lake Regions document may be obtained from the Department's internet site at http://www.dep.state.fl.us/water/wqssp/swq-docs.htm or by writing to the Florida Department of Environmental Protection, Standards and Assessment Section, 2600 Blair Stone Road, MS 6511, Tallahassee, FL 32399-2400.

(20) ~~(17)~~ "Nuisance ~~s~~Species" shall mean species of flora or fauna whose noxious characteristics or presence in sufficient number, biomass, or areal extent may reasonably be expected to prevent, or unreasonably interfere with, a designated use of those waters.

(21) ~~(18)~~ "Nursery ~~a~~Area of ~~i~~Indigenous ~~a~~Aquatic ~~l~~Life" shall mean any bed of the following aquatic plants, either in monoculture or mixed: Halodule wrightii, Halophila spp., Potamogeton spp. (pondweed), Ruppia maritima (widgeon-grass), Sagittaria spp. (arrowhead), Syringodium filiforme (manatee-grass), Thalassia testudinum (turtle grass), or Vallisneria spp. (eel-grass), or any area used by the early-life stages, larvae and post-larvae, of aquatic life during the period of rapid growth and development into the juvenile states.

(22) "Nutrient" shall mean total nitrogen (TN), total phosphorus (TP), or their organic or inorganic forms.

(23) "Nutrient response variable" shall mean a biological variable, such as chlorophyll *a*, biomass, or structure of the phytoplankton, periphyton or vascular plant community, that responds to nutrient load or concentration in a predictable and measurable manner. For purposes of interpreting paragraph 62-302.530(47)(b), F.A.C., dissolved oxygen (DO) shall also be considered a nutrient response variable if it is demonstrated for the waterbody that DO conditions result in biological imbalance and the DO responds to a nutrient load or concentration in a predictable and measurable manner.

(24) "Nutrient Threshold" shall mean a concentration of nutrients that applies to a Nutrient Watershed Region and is derived from a statistical distribution of data from reference or benchmark sites. Nutrient Thresholds are only applied to streams as specified in paragraph 62-302.531(2)(c), F.A.C.

(25) "Nutrient Watershed Region" shall mean a drainage area over which the nutrient thresholds in paragraph 62-302.531(2)(c), F.A.C., apply.

(a) The Panhandle West region consists of the Perdido Bay Watershed, Pensacola Bay Watershed, Choctawhatchee Bay Watershed, St. Andrew Bay Watershed, and Apalachicola Bay Watershed.

(b) The Panhandle East region consists of the Apalachee Bay Watershed, and Econfina/Steinhatchee Coastal Drainage Area.

(c) The North Central region consists of the Suwannee River Watershed and the "stream to sink" region in Alachua, Marion and Levy Counties that is affected by the Hawthorne Formation.

(d) The West Central region consists of the Peace, Myakka, Hillsborough, Alafia, Manatee, Little Manatee River Watersheds, Sarasota/Lemon Bay Watershed and small, direct Tampa Bay tributary watersheds south of the Hillsborough River Watershed.

(e) The Peninsula region consists of the Waccasassa Coastal Drainage Area, Withlacoochee Coastal Drainage Area, Crystal/Pithlachascotee Coastal Drainage Area, small, direct Tampa Bay tributary watersheds west of the Hillsborough River Watershed, small, direct Charlotte Harbor tributary watersheds south of the Peace River Watershed, Caloosahatchee River Watershed, Estero Bay Watershed, Imperial River Watershed, Kissimmee River/Lake Okeechobee Drainage Area, Loxahatchee/St. Lucie Watershed, Indian River Watershed, Daytona/St. Augustine Coastal Drainage Area, St. John's River Watershed, Nassau Coastal Drainage Area, and St. Mary's River Watershed.

(f) The South Florida region consists of those areas south of the Peninsula region, such as the Cocohatchee River Watershed, Naples Bay Watershed, Rookery Bay Watershed, Ten Thousand Islands Watershed, Lake Worth Lagoon Watershed, Southeast Coast – Biscayne Bay Watershed, Everglades Watershed, Florida Bay Watershed, and the Florida Keys.
A map of the Nutrient Watershed Regions, dated October 17, 2011, is incorporated by reference herein and may be obtained from the Department's internet site at http://www.dep.state.fl.us/water/wqssp/swq-docs.htm or by writing to the Florida Department of Environmental Protection, Standards and Assessment Section, 2600 Blair Stone Road, MS 6511, Tallahassee, FL 32399-2400.

(19) through (21) renumber (26) through (28) No change.

(29) ~~(22)~~ "Predominantly ~~f~~Fresh ~~w~~Waters" shall mean surface waters in which the chloride concentration ~~at the surface~~ is less than 1,500 milligrams per liter or specific conductance is less than 4,580 µmhos/cm.

(30) ~~(23)~~ "Predominantly ~~m~~Marine ~~w~~Waters" shall mean surface waters in which the chloride concentration ~~at the surface~~ is greater than or equal to 1,500 milligrams per liter or specific conductance is greater than or equal to 4,580 µmhos/cm.

(24) through (26) renumber (31) through (33) No change.

(34) ~~(27)~~ "Special Waters" shall mean water bodies designated in accordance with Rule 62-302.700, F.A.C., by the Environmental Regulation Commission for inclusion in the Special Waters Category of Outstanding Florida Waters, as contained in Rule 62-302.700, F.A.C. A Special Water may include all or part of any waterbody ~~water body~~.

(35) "Spring vent" shall mean a location where groundwater flows out of a natural, discernable opening in the ground onto the land surface or into a predominantly fresh surface water.

(36) "Stream" shall mean, for purposes of interpreting the narrative nutrient criterion in paragraph 62-302.530(47)(b), F.A.C., under paragraph 62-302.531(2)(c), F.A.C., a predominantly fresh surface waterbody with perennial flow in a defined channel with banks during typical climatic and hydrologic conditions for its region within the state. During periods of drought, portions of a stream channel may exhibit a dry bed, but wetted pools are typically still present during these conditions. Streams do not include:

(a) non-perennial water segments where fluctuating hydrologic conditions, including periods of desiccation, typically result in the dominance of wetland and/or terrestrial taxa (and corresponding reduction in obligate fluvial or lotic taxa), wetlands, ~~or~~ portions of streams that exhibit lake characteristics (e.g., long water residence time, increased width, or predominance of biological taxa typically found in non-flowing conditions) or tidally influenced segments that fluctuate between predominantly marine and predominantly fresh waters during typical climatic and hydrologic conditions; or

(b) ditches, canals and other conveyances, or segments of conveyances, that are man-made, or predominantly channelized or predominantly physically altered and:

1. are primarily used for water management purposes, such as flood protection, stormwater management, irrigation, or water supply; and

2. have marginal or poor stream habitat or habitat components, such as a lack of habitat or substrate that is biologically limited, because the conveyance has cross sections that are predominantly trapezoidal, has armored banks, or is maintained primarily for water conveyance.

(37) "Stream Condition Index (SCI)" shall mean a Biological Health Assessment that measures stream biological health in predominantly freshwaters using benthic macroinvertebrates, performed and calculated using the Standard Operating Procedures for the SCI in the document titled *SCI 1000: Stream Condition Index Methods* (DEP-SOP-003/11 SCI 1000) and the methodology in *Sampling and Use of the Stream Condition Index (SCI) for Assessing Flowing Waters: A Primer* (DEP-SAS-001/11), both dated 10-24-11, which are incorporated by reference herein. Copies of the documents may be obtained from the Department's internet site at http://www.dep.state.fl.us/water/wqssp/swq-docs.htm or by writing to the Florida Department of Environmental Protection, Standards and Assessment Section, 2600 Blair Stone Road, MS 6511, Tallahassee, FL 32399-2400. For water quality standards purposes, the Stream Condition Index shall not apply in the South Florida Nutrient Watershed Region.

(38) ~~(28)~~ "Surface w~~W~~ater" means water upon the surface of the earth, whether contained in bounds created naturally or artificially or diffused. Water from natural springs shall be classified as surface water when it exits from the spring onto the earth's surface.

(39) "Total Maximum Daily Load" (TMDL) for an impaired waterbody or waterbody segment shall mean the sum of the individual wasteload allocations for point sources and the load allocations for nonpoint sources and natural background. Prior to determining individual wasteload allocations and load allocations, the maximum amount of a pollutant that a waterbody or water segment can assimilate from all sources without exceeding water quality standards must first be calculated. A TMDL shall include either an implicit or explicit margin of safety and a consideration of seasonal variations.

(40) ~~(29)~~ "Total r~~R~~ecoverable m~~M~~etal" shall mean the concentration of metal in an unfiltered sample following treatment with hot dilute mineral acid.

(41) ~~(30)~~ No change.

(42) ~~(31)~~ "Water quality standards" shall mean standards composed of designated present and future most beneficial uses (classification of waters), the numerical and narrative criteria, including Site Specific Alternative Criteria, applied to the specific water uses or classification, the Florida anti-degradation policy, and the moderating provisions, such as variances, mixing zone rule provisions, or exemptions. ~~contained in this rule and in Chapter 62-4, adopted pursuant to Chapter 403, F.S.~~

(43) ~~(32)~~ No change.

(44) ~~(33)~~ "Zone of mMixing" or "mMixing zZone" shall mean a volume of surface water containing the point or area of discharge and within which an opportunity for the mixture of wastes with receiving surface waters has been afforded.

Rulemaking Authority 403.061, 403.062, 403.087, 403.504, 403.704, 403.804, 403.805 FS. Law Implemented 403.021, 403.031, 403.061, 403.062, 403.085, 403.086, 403.087, 403.088, 403.502, 403.802 FS. History - New 05-29-90, Amended 2-13-92, Formerly 17-302.200, Amended 1-23-95, 5-15-02, 4-2-08, - -11.

62-302.530 Table: Surface Water Quality Criteria.

The following table contains both numeric and narrative surface water quality criteria to be applied except within zones of mixing. The left-hand column of the Table is a list of constituents for which a surface water criterion exists. The headings for the water quality classifications are found at the top of the Table, and the classification descriptions for the headings are specified in subsection 62-302.400(1), F.A.C. Applicable criteria lie within the Table. The individual criteria should be read in conjunction with other provisions in water quality standards, including Rule 62-302.500, F.A.C. The criteria contained in Rule 62-302.500, F.A.C., also apply to all waters unless alternative or more stringent criteria are specified in Rule 62-302.530, F.A.C. Unless otherwise stated, all criteria express the maximum not to be exceeded at any time. In some cases, there are separate or additional limits, which apply independently of the maximum not to be exceeded at any time. For example, annual average (denoted as "annual avg." in the Table) means the maximum concentration at average annual flow conditions (see subsection 62-302.200(2), F.A.C.). Numeric interpretations of the narrative nutrient criterion in paragraph 62-302.530 (47)(b), F.A.C., shall be expressed as spatial averages and applied over a spatial area consistent with their derivation. In applying the water quality standards, the Department shall take into account the variability occurring in nature and shall recognize the statistical variability inherent in sampling and testing procedures. The Department's assessment methodology, set forth in Chapter 62-303, F.A.C., accounts for such natural and statistical variability when used to assess ambient waters pursuant to sections 305(b) and 303(d) of the Federal Clean Water Act.

(1) through (70) No change.

Rulemaking Authority 403.061, 403.062, 403.087, 403.504, 403.704, 403.804 FS. Law Implemented 403.021, 403.061, 403.087, 403.088, 403.141, 403.161, 403.182, 403.502, 403.702, 403.708 FS. History–New 1-28-90, Formerly 17-3.065, Amended 2-13-92, 6-17-92, Formerly 17-302.540, 17-302.550, 17-302.560, 17-302.570, 17-302.580, Amended 4-25-93, Formerly 17-302.530, Amended 1-23-95, 1-15-96, 5-15-02, 7-19-04, 12-7-06, 8-5-10, - -11.

62-302.531 Numeric Interpretations of Narrative Nutrient Criteria.

(1) The narrative water quality criteria for nutrients in paragraphs 62-302.530(47)(a) and (b), F.A.C., applies to all Class I, Class II, and Class III waters.

(2) The narrative water quality criterion for nutrients in paragraph 62-302.530(47)(b), F.A.C., shall be numerically interpreted for both nutrients and nutrient response variables in a hierarchical manner as follows:

(a) Where a site specific numeric interpretation of the criterion in paragraph 62-302.530(47)(b), F.A.C., has been established by the Department, this numeric interpretation shall be the primary interpretation. If there are multiple interpretations of the narrative criterion for a waterbody, the most recent interpretation established by the Department shall apply. A list of the site specific numeric interpretations of paragraph 62-302.530(47)(b), F.A.C., may be obtained from the Department's internet site at http://www.dep.state.fl.us/water/wqssp/swq-docs.htm or by writing to the Florida Department of Environmental Protection, Standards and Assessment Section, 2600 Blair Stone Road, MS 6511, Tallahassee, FL 32399-2400.

1. The primary site specific interpretations are as follows:

a. Total Maximum Daily Loads (TMDLs) adopted under Chapter 62-304, F.A.C., that interpret the narrative water quality criterion for nutrients in paragraph 62-302.530(47)(b), F.A.C., for one or more nutrients or nutrient response variables;

b. Site specific alternative criteria (SSAC) for one or more nutrients or nutrient response variables as established under Rule 62-302.800, F.A.C.;

c. Estuary-specific numeric interpretations of the narrative nutrient criterion established in Rule 62-302.532, F.A.C.; or

d. Other site specific interpretations for one or more nutrients or nutrient response variables that are formally established by rule or final order by the Department, such as a Reasonable Assurance Demonstration pursuant to

Rule 62-303.600, F.A.C., or Level II Water Quality Based Effluent Limitations (WQBEL) established pursuant to Rule 62-650.500, F.A.C. To be recognized as the applicable site specific numeric interpretation of the narrative nutrient criterion, the interpretation must establish the total allowable load or ambient concentration for at least one nutrient that results in attainment of the applicable nutrient response variable that represents achievement of the narrative nutrient criterion for the waterbody. A site specific interpretation is also allowable where there are documented adverse biological effects using one or more Biological Health Assessments, if information on chlorophyll *a* levels, algal mats or blooms, nuisance macrophyte growth, and changes in algal species composition indicate there are no imbalances in flora and a stressor identification study demonstrates that the adverse biological effects are not due to nutrients.

2. For the primary site specific interpretations in subparagraph 62-302.531(2)(a)1., F.A.C., the notice of rulemaking or other public notice shall state that the Department is establishing a site specific interpretation for the receiving waterbody, and offer an opportunity for a public meeting and public comment.

(b) If site specific numeric interpretations, as described in paragraph 62-302.531(2)(a), F.A.C., above, have not been established for a waterbody, but there is an established, quantifiable cause-and-effect relationship between one or more nutrients and nutrient response variables linked to a value that protects against an imbalance in the natural populations of the aquatic flora or fauna, then the numeric values for the nutrients or nutrient response variables, set forth in this paragraph (2)(b), shall be the applicable interpretations. Absent a numeric interpretation as established in paragraph 62-302.531(2)(a), F.A.C., site specific numeric interpretations are established as follows:

1. For lakes, the applicable numeric interpretations of the narrative nutrient criterion in paragraph 62-302.530(47)(b), F.A.C., for chlorophyll *a* are shown in the table below. The applicable interpretations for TN and TP will vary on an annual basis, depending on the availability of chlorophyll *a* data and the concentrations of nutrients and chlorophyll *a* in the lake, as described below. The applicable numeric interpretations for TN, TP, and chlorophyll *a* shall not be exceeded more than once in any consecutive three year period.

a. If there are sufficient data to calculate the annual geometric mean chlorophyll *a* and the mean does not exceed the chlorophyll *a* value for the lake type in the table below, then the TN and TP numeric interpretations for that calendar year shall be the annual geometric means of lake TN and TP samples, subject to the minimum and maximum limits in the table below. However, for lakes with color > 40 PCU in the West Central Nutrient Watershed Region, the maximum TP limit shall be the 0.49 mg/L TP streams threshold for the region; or

b. If there are insufficient data to calculate the annual geometric mean chlorophyll *a* for a given year or the annual geometric mean chlorophyll *a* exceeds the values in the table below for the lake type, then the applicable numeric interpretations for TN and TP shall be the minimum values in the table below.

Long Term Geometric Mean Lake Color and Alkalinity	Annual Geometric Mean Chlorophyll *a*	Minimum calculated numeric interpretation		Maximum calculated numeric interpretation	
		Annual Geometric Mean Total Phosphorus	Annual Geometric Mean Total Nitrogen	Annual Geometric Mean Total Phosphorus	Annual Geometric Mean Total Nitrogen
> 40 Platinum Cobalt Units	20 µg/L	0.05 mg/L	1.27 mg/L	0.16 mg/L[1]	2.23 mg/L
≤ 40 Platinum Cobalt Units and > 20 mg/L $CaCO_3$	20 µg/L	0.03 mg/L	1.05 mg/L	0.09 mg/L[1]	1.91 mg/L
≤ 40 Platinum Cobalt Units and ≤ 20 mg/L $CaCO_3$	6 µg/L	0.01 mg/L	0.51 mg/L	0.03 mg/L[1]	0.93 mg/L

[1] For lakes with color > 40 PCU in the West Central Nutrient Watershed Region, the maximum TP limit shall be the 0.49 mg/L TP streams threshold for the region.

c. For the purpose of subparagraph 62-302.531(2)(b)1., F.A.C., color shall be assessed as true color and shall be free from turbidity. Lake color and alkalinity shall be the long-term geometric mean, based on a minimum of ten data points over at least three years with at least one data point in each year. If insufficient alkalinity data are

available, long-term geometric mean specific conductance values shall be used, with a value of <100 micromhos/cm used to estimate the 20 mg/L $CaCO_3$ alkalinity concentration until such time that alkalinity data are available.

2. For spring vents, the applicable numeric interpretation of the narrative nutrient criterion in paragraph 62-302.530(47)(b), F.A.C., is 0.35 mg/L of nitrate-nitrite ($NO_3 + NO_2$) as an annual geometric mean, not to be exceeded more than once in any three calendar year period.

(c) For streams, if a site specific interpretation pursuant to paragraph 62-302.531(2)(a) or (2)(b), F.A.C., has not been established, biological information shall be used to interpret the narrative nutrient criterion in combination with Nutrient Thresholds. The narrative nutrient criterion in paragraph 62-302.530(47)(b), F.A.C., shall be interpreted as being achieved in a stream segment where information on chlorophyll *a* levels, algal mats or blooms, nuisance macrophyte growth, and changes in algal species composition indicates there are no imbalances in flora or fauna, and either:

1. the average score of at least two temporally independent SCIs performed at representative locations and times is 40 or higher, with neither of the two most recent SCI scores less than 35, or

2. the nutrient thresholds set forth in the table below are achieved.

Nutrient Watershed Region	Total Phosphorus Nutrient Threshold[1]	Total Nitrogen Nutrient Threshold[1]
Panhandle West	0.06 mg/L	0.67 mg/L
Panhandle East	0.18 mg/L	1.03 mg/L
North Central	0.30 mg/L	1.87 mg/L
Peninsular	0.12 mg/L	1.54 mg/L
West Central	0.49 mg/L	1.65 mg/L
South Florida	No numeric nutrient threshold. The narrative criterion in paragraph 62-302.530(47)(b), F.A.C., applies.	No numeric nutrient threshold. The narrative criterion in paragraph 62-302.530(47)(b), F.A.C., applies.

[1]These values are annual geometric mean concentrations not to be exceeded more than once in any three calendar year period.

(3) Except for data used to establish historical chlorophyll *a* levels, chlorophyll *a* data assessed under this Chapter shall be measured according to the DEP document titled "Applicability of Chlorophyll *a* Methods" (DEP-SAS-002/10), dated October 24, 2011, which is incorporated by reference herein. Copies of the chlorophyll *a* document may be obtained from the Department's internet site at http://www.dep.state.fl.us/water/wqssp/swq-docs.htm or by writing to the Florida Department of Environmental Protection, Standards and Assessment Section, 2600 Blair Stone Road, MS 6511, Tallahassee, FL 32399-2400. Chlorophyll *a* data collected after [effective date] shall be corrected for or free from the interference of phaeophytin.

(4) The loading of nutrients from a waterbody shall be limited as necessary to provide for the attainment and maintenance of water quality standards in downstream waters.

(5) To qualify as temporally independent samples, each SCI shall be conducted at least three months apart. SCIs collected at the same location less than three months apart shall be considered one sample, with the mean value used to represent the sampling period.

(6) To calculate an annual geometric mean for TN, TP, or chlorophyll *a*, there shall be at least four temporally-independent samples per year with at least one sample taken between May 1 and September 30 and at least one sample taken during the other months of the calendar year. To be treated as temporally-independent, samples must be taken at least one week apart.

(7) The numeric interpretation of the narrative nutrient criterion shall be applied over a spatial area consistent with its derivation.

(a) For numeric interpretations based on paragraph 62-302.531(2)(a), F.A.C., the spatial application of the numeric interpretation is as defined in the associated order or rule.

(b) For lakes covered under subparagraph 62-302.531(2)(b)1., F.A.C., the numeric interpretation shall be applied as a lake-wide or lake segment-wide average.

(c) For spring vents covered under subparagraph 62-302.531(2)(b)2., F.A.C., the numeric interpretation shall be applied in the surface water at or above the spring vent.

(d) For streams covered under paragraph 62-302.531(2)(c), F.A.C., the spatial application of the numeric interpretation shall be determined by relative stream homogeneity and shall be applied to waterbody segments or aggregations of segments as determined by the site-specific considerations.

(8) Load-based or percent reduction-based nutrient TMDLs or Level II Water Quality Based Effluent Limitations (WQBELs) pursuant to Chapter 62-650, F.A.C., do not need to be converted into concentration-based nutrient TMDLs or WQBELs to be used as the basis for the numeric interpretation of the narrative criterion. For percent reduction-based nutrient TMDLs, the associated allowable load or concentration is the numeric interpretation of the narrative criterion for the waterbody.

(9) The Commission adopts rules 62-302.200(4), .200(16)-(17), .200(22)-(25), .200(35)-(37), .200(39), 62-302.531, and 62-302.532(3), F.A.C., to ensure, as a matter of policy, that nutrient pollution is addressed in Florida in an integrated, comprehensive and consistent manner. Accordingly, these rules shall be effective only if EPA approves these rules in their entirety, concludes rulemaking that removes federal numeric nutrient criteria in response to the approval, and determines, in accordance with 33 U.S.C. § 1313(c)(3), that these rules sufficiently address EPA's January 14, 2009 determination. If any provision of these rules is determined to be invalid by EPA or in any administrative or judicial proceeding, then the entirety of these rules shall not be implemented.

Rulemaking Authority 403.061, 403.062, 403.087, 403.504, 403.704, 403.804 FS. Law Implemented 403.021, 403.061, 403.067, 403.087, 403.088, 403.141, 403.161, 403.182, 403.502, 403.702, 403.708 FS. History – New _ -11.

62-302.532 Estuary-Specific Numeric Interpretations of the Narrative Nutrient Criterion.

(1) Estuary-specific numeric interpretations of the narrative nutrient criterion in paragraph 62-302.530(47)(b), F.A.C., are in the table below. The concentration-based estuary interpretations are open water, area-wide averages. The interpretations expressed as load per million cubic meters of freshwater inflow are the total load of that nutrient to the estuary divided by the total volume of freshwater inflow to that estuary.

Estuary	Total Phosphorus	Total Nitrogen	Chlorophyll *a*
(a) Clearwater Harbor/St. Joseph Sound	Annual geometric mean values not to be exceeded more than once in a three year period. Nutrient and nutrient response values do not apply to tidally influenced areas that fluctuate between predominantly marine and predominantly fresh waters during typical climatic and hydrologic conditions.		
1. St.Joseph Sound	0.05 mg/L	0.66 mg/L	3.1 µg/L
2. Clearwater North	0.05 mg/L	0.61 mg/L	5.4 µg/L
3. Clearwater South	0.06 mg/L	0.58 mg/L	7.6 µg/L
(b) Tampa Bay	Annual totals for nutrients and annual arithmetic means for chlorophyll a, not to be exceeded more than once in a three year period. Nutrient and nutrient response values do not apply to tidally influenced areas that fluctuate between predominantly marine and predominantly fresh waters during typical climatic and hydrologic conditions.		
1. Old Tampa Bay	0.23 tons/million cubic meters of water	1.08 tons/million cubic meters of water	9.3 µg/L
2. Hillsborough Bay	1.28 tons/million cubic meters of water	1.62 tons/million cubic meters of water	15.0 µg/L
3. Middle Tampa Bay	0.24 tons/million cubic meters of water	1.24 tons/million cubic meters of water	8.5 µg/L
4. Lower Tampa Bay	0.14 tons/million cubic meters of	0.97 tons/million cubic meters of	5.1 µg/L

	water	water	
5. Boca Ciega North	0.18 tons/million cubic meters of water	1.54 tons/million cubic meters of water	8.3 µg/L
6. Boca Ciega South	0.06 tons/million cubic meters of water	0.97 tons/million cubic meters of water	6.3 µg/L
7. Terra Ceia Bay	0.14 tons/million cubic meters of water	1.10 tons/million cubic meters of water	8.7 µg/L
8. Manatee River Estuary	0.37 tons/million cubic meters of water	1.80 tons/million cubic meters of water	8.8 µg/L
(c) Sarasota Bay	Annual geometric mean values for nutrients and annual arithmetic means for chlorophyll a, not to be exceeded more than once in a three year period. Nutrient and nutrient response values do not apply to tidally influenced areas that fluctuate between predominantly marine and predominantly fresh waters during typical climatic and hydrologic conditions.		
1. Palma Sola Bay	0.26 mg/L	0.93 mg/L	11.8 µg/L
2. Sarasota Bay	0.19 mg/L	See paragraph 62-302.532(3)(i), F.A.C.	6.1 µg/L
3. Roberts Bay	0.23 mg/L	0.54 mg/L	11.0 µg/L
4. Little Sarasota Bay	0.21 mg/L	0.60 mg/L	10.4 µg/L
5. Blackburn Bay	0.21 mg/L	0.43 mg/L	8.2 µg/L
(d) Charlotte Harbor/Estero Bay	Annual arithmetic mean values for nutrients and annual arithmetic means for chlorophyll a, not to be exceeded more than once in a three year period. Nutrient and nutrient response values do not apply to tidally influenced areas that fluctuate between predominantly marine and predominantly fresh waters during typical climatic and hydrologic conditions.		
1. Dona and Roberts Bay	0.18 mg/L	0.42 mg/L	4.9 µg/L
2. Upper Lemon Bay	0.26 mg/L	0.56 mg/L	8.9 µg/L
3. Lower Lemon Bay	0.17 mg/L	0.62 mg/L	6.1 µg/L
4. Charlotte Harbor Proper	0.19 mg/L	0.67 mg/L	6.1 µg/L
5. Pine Island Sound	0.06 mg/L	0.57 mg/L	6.5 µg/L
6. San Carlos Bay	0.07 mg/L	0.56 mg/L	3.5 µg/L
7. Tidal Myakka River	0.31 mg/L	1.02 mg/L	11.7 µg/L
8. Matlacha Pass	0.08 mg/L	0.58 mg/L	6.1 µg/L
9.Estero Bay (including Tidal Imperial River)	0.07 mg/L	0.63 mg/L	5.9 µg/L
(e) Tidal Cocohatchee River/Ten Thousand Islands	Annual geometric means that shall not be exceeded more than once in a three year period		
1. Tidal Cocohatchee River	0.057 mg/L	0.47 mg/L	5.8 µg/L
2. Collier Inshore	0.032 mg/L	0.25 mg/L	3.1 µg/L
3. Rookery Bay/Marco Island	0.046 mg/L	0.30 mg/L	4.9 µg/L
4. Naples Bay	0.045 mg/L	0.57mg/L	4.3 µg/L
5. Inner Gulf Shelf	0.018 mg/L	0.29 mg/L	1.6 µg/L
6. Middle Gulf Shelf	0.016 mg/L	0.26 mg/L	1.4 µg/L
7. Outer Gulf Shelf	0.013 mg/L	0.22 mg/L	1.0 µg/L
8. Blackwater River	0.053 mg/L	0.41 mg/L	4.1 µg/L
9. Coastal Transition Zone	0.034 mg/L	0.61 mg/L	3.9 µg/L

10. Gulf Islands	0.038 mg/L	0.44 mg/L	3.4 µg/L
11. Inner Waterway	0.033 mg/L	0.69 mg/L	5.2 µg/L
12. Mangrove Rivers	0.021 mg/L	0.71 mg/L	3.7 µg/L
13. Ponce de Leon	0.024 mg/L	0.52 mg/L	3.0 µg/L
14. Shark River Mouth	0.022 mg/L	0.75 mg/L	2.2 µg/L
15. Whitewater Bay	0.026 mg/L	0.82 mg/L	4.1 µg/L
(f) Florida Bay	Annual geometric means that shall not be exceeded more than once in a three year period		
1. Central Florida Bay	0.019 mg/L	0.99 mg/L	2.2 µg/L
2. Coastal Lakes	0.045 mg/L	1.29 mg/L	9.3 µg/L
3. East Central Florida Bay	0.007 mg/L	0.65 mg/L	0.4 µg/L
4. Northern Florida Bay	0.010 mg/L	0.68 mg/L	0.8 µg/L
5. Southern Florida Bay	0.009 mg/L	0.64 mg/L	0.8 µg/L
6. Western Florida Bay	0.015 mg/L	0.37 mg/L	1.4 µg/L
(g) Florida Keys	Annual geometric means that shall not be exceeded more than once in a three year period		
1. Back Bay	0.009 mg/L	0.25 mg/L	0.3 µg/L
2. Backshelf	0.011 mg/L	0.23 mg/L	0.7 µg/L
3. Lower Keys	0.008 mg/L	0.21 mg/L	0.3 µg/L
4. Marquesas	0.008 mg/L	0.21 mg/L	0.6 µg/L
5. Middle Keys	0.007 mg/L	0.22 mg/L	0.3 µg/L
6. Oceanside	0.007 mg/L	0.17 mg/L	0.3 µg/L
7. Upper Keys	0.007 mg/L	0.18 mg/L	0.2 µg/L
(h) Biscayne Bay	Annual geometric means that shall not be exceeded more than once in a three year period		
1. Card Sound	0.008 mg/L	0.33 mg/L	0.5 µg/L
2. Manatee Bay – Barnes Sound	0.007 mg/L	0.58 mg/L	0.4 µg/L
3. North Central Inshore	0.007 mg/L	0.31 mg/L	0.5 µg/L
4. North Central Outer-Bay	0.008 mg/L	0.28 mg/L	0.7 µg/L
5. Northern North Bay	0.012 mg/L	0.30 mg/L	1.7 µg/L
6. South Central Inshore	0.007 mg/L	0.48 mg/L	0.4 µg/L
7. South Central Mid-Bay	0.007 mg/L	0.35 mg/L	0.2 µg/L
8. South Central Outer-Bay	0.006 mg/L	0.24 mg/L	0.2 µg/L
9. Southern North Bay	0.010 mg/L	0.29 mg/L	1.1 µg/L

(i) Sarasota Bay	For TN, the annual geometric mean target is calculated from monthly arithmetic mean color by region and season. Annual geometric means that shall not be exceeded more than once in a three year period. The Sarasota Bay regions are defined as north (Manatee County) and south (Sarasota County). The wet season for Sarasota Bay is defined as July through October and the dry season is defined as all other months of the year. The seasonal region targets are calculated using monthly color data and shall be calculated as follows: NW_i=Ln[(13.35-(0.32*CN_i))/3.58] ND_i=Ln[(10.39-(0.32*CN_i))/3.58] SW_i=Ln[(8.51-(0.32*CS_i)/3.58] SD_i=Ln[(5.55-(0.32*CS_i))/3.58] Where, NW_i is the TN target for i^{th} month calculated for the north region during the wet season ND_i is the TN target for i^{th} month calculated for the north region during the dry

	season SW_i is the TN target for i^{th} month calculated for the south region during the wet season SW_i is the TN target for i^{th} month calculated for the south region during the dry season CN_i is the arithmetic mean color during the i^{th} month within the north region CS_i is the arithmetic mean color during the i^{th} month within the south region The annual TN target is calculated as the geometric mean of all monthly regional and season targets as follows: $e^{\sum_i^{12}\left(\frac{NWi+NDi+SWi+SDi}{24}\right)}$ Nutrient and nutrient response values do not apply to tidally influenced areas that fluctuate between predominantly marine and predominantly fresh waters during typical climatic and hydrologic conditions.

(j) Clam Bay (Collier County)	No more than 10 percent of the individual Total Phosphorus (TP) or Total Nitrogen (TN) measurements shall exceed the respective TP Upper Limit or TN Upper Limit.	
	TP Upper Limit (mg/L) = $e^{(-1.06256-0.0000328465*\text{Conductivity }(\mu S))}$	TN Upper Limit (mg/L) = 2.3601 – 0.0000268325*Conductivity (µS)

(2) Estuarine and marine areas are delineated in the eight maps of the Florida Marine Nutrient Regions, all dated October 19, 2011, which are incorporated by reference. Copies of these maps may be obtained from the Department's internet site at http://www.dep.state.fl.us/water/wqssp/swq-docs.htm or by writing to the Florida Department of Environmental Protection, Standards and Assessment Section, 2600 Blair Stone Road, MS 6511, Tallahassee, FL 32399-2400.

(3) The Department shall establish by rule or final order estuary specific numeric interpretations of the narrative nutrient criteria for TN and TP for Perdido Bay, Pensacola Bay (including Escambia Bay), St. Andrews Bay, Choctawhatchee Bay, and Apalachicola Bay by June 30, 2013, subject to the provisions of Chapter 120, F.S. The Department shall establish by rule or final order the estuary specific numeric interpretation of the narrative nutrient criteria for TN and TP for the remaining estuaries by June 30, 2015, subject to the provisions of Chapter 120, F.S.

Rulemaking Authority 403.061, 403.062, 403.087, 403.504, 403.704, 403.804 FS. Law Implemented 403.021, 403.061, 403.087, 403.088, 403.141, 403.161, 403.182, 403.502, 403.702, 403.708 FS. History – New - -11.

62-302.800 Site Specific Alternative Criteria.

(1) Type I Site Specific Alternative Criteria: A waterbody ~~water body~~, or portion thereof, may not meet a particular ambient water quality criterion specified for its classification, due to natural background conditions or man-induced conditions which cannot be controlled or abated. In such circumstances, and upon petition by an affected person or upon the initiation by the Department, the Secretary may establish a site specific alternative water quality criterion when an affirmative demonstration is made that an alternative criterion is more appropriate for a specified portion of waters of the state. Public notice and an opportunity for public hearing shall be provided prior to issuing any order establishing alternative criteria.

(a) The affirmative demonstration required by this section shall mean a documented showing that the proposed alternative criteria would exist due to natural background conditions or man-induced conditions which cannot be controlled or abated. Such demonstration shall be based upon relevant factors which include:

1. A description of the physical nature of the specified waterbody ~~water body~~ and the water pollution sources affecting the criterion to be altered.

2. through 4. No change.

(b) No change.

(2) Type II Site Specific Alternative Criteria: In accordance with the procedures set forth below, affected persons may petition the Department, or the Department may initiate rulemaking, to adopt an alternative water quality criterion for a specific waterbody ~~water body~~, or portion thereof, on the basis of site-specific reasons other than those set forth above in subsection 62-302.800(1), F.A.C. The Department shall process any such petition as follows:

(a) through (c)1. No change.

2. In making the demonstration required by this paragraph (c), the petition shall include an assessment of aquatic toxicity, except on a showing that no such assessment is relevant to the particular criterion. The assessment of aquatic toxicity shall show that physical and chemical conditions at the site alter the toxicity or bioavailability of the compound in question and shall meet the requirements and follow the Indicator Species procedure set forth in *Water Quality Standards Handbook* (December 1983), a publication of the United States Environmental Protection Agency, incorporated here by reference. If, however, the Indicator Species Procedure is not applicable to the proposed site-specific alternative criterion, the petitioner may propose another generally accepted scientific method or procedure to demonstrate with equal assurance that the alternative criterion will protect the aquatic life designated use of the waterbody ~~water body~~.

3. through 7. No change.

(d) The provisions of this subsection do not apply to criteria contained in Rule 62-302.500, F.A.C., or criteria that apply to:

1. Biological Integrity (subsection 62-302.530(10), F.A.C.).

2. B.O.D. (subsection 62-302.530(11), F.A.C.).

~~3. Nutrients.~~

3. ~~4.~~ Odor (subsections 62-302.500(1), 62-302.530(21), 62-302.530(48), and paragraphs 62-302.530 (49)(b) and 62-302.530(52)(a), F.A.C.).

4. ~~5.~~ Oils and Greases (subsection 62-302.530(49), F.A.C.).

5. ~~6.~~ Radioactive Substances (subsection 62-302.530(57), F.A.C.).

6. ~~7.~~ Substances in concentrations that injure, are chronically toxic to, or produce adverse physiological or behavioral response in humans, animals, or plants (subsection 62-302.530(61), F.A.C.).

7. ~~8.~~ Substances, other than nutrients, in concentrations that result in the dominance of nuisance species (subsection 62-302.200(20), F.A.C.).

8. ~~9.~~ Total Dissolved Gases (subsection 62-302.530(66), F.A.C.).

9. ~~10~~ No change.

(e) through (f) No change.

(3) Type III Site Specific Alternative Criteria (SSAC) for Nutrients: Upon petition by an affected person or upon initiation by the Department, the Department shall establish, by Secretarial Order, site specific numeric nutrient criteria when an affirmative demonstration is made that the proposed criteria achieve the narrative nutrient criteria in paragraph 62-302.530(47)(b), F.A.C., and are protective of downstream waters. Public notice and an opportunity for public hearing shall be provided prior to adopting any order establishing alternative criteria under this subsection.

(a) The Department shall establish a Type III SSAC if all of the following conditions are met:

1. The petitioner demonstrates that the waterbody achieves the narrative nutrient criteria in paragraph 62-302.530(47)(b), F.A.C.

a. For streams, such a demonstration shall require:

i. information on chlorophyll *a* levels, algal mats or blooms, nuisance macrophyte growth, and changes in algal species composition indicating that there is not an imbalance in flora, and

ii. at least two temporally independent SCIs, conducted at a minimum of two spatially-independent stations representative of the waterbody or water segment for which a SSAC is requested, with an average score of 40 or higher, with neither of the two most recent SCI scores less than 35.

b. For lakes, such a demonstration shall require:

i. information on chlorophyll *a* levels, algal mats or blooms indicating that there is not an imbalance in flora or fauna, and

ii. at least two temporally independent LVIs, with an average score of 43 or above.

c. SCIs and LVIs collected at the same location less than three months apart shall be considered to be one sample, with the mean value used to represent the sampling period. SCIs and LVIs shall be conducted during the

water quality sampling period described in subparagraph 62-302.800(3)(a)2, F.A.C. There shall be a minimum of two assessments per station or lake, with at least one assessment conducted during the final year.

2. The petitioner provides sufficient data to characterize water quality conditions, including temporal variability, that are representative of the biological data used to support the SSAC. The water quality data shall be collected in the same waterbody segment as the biological monitoring stations and at a frequency and duration consistent with the study design concepts described in the document titled *Development of Type III Site Specific Alternative Criteria (SSAC) for Nutrients* (DEP-SAS-004/11), dated October 24, 2011, which is incorporated by reference herein. Copies of this document may be obtained from the Department's internet site at http://www.dep.state.fl.us/water/wqssp/swq-docs.htm or by writing to the Florida Department of Environmental Protection, Standards and Assessment Section, 2600 Blair Stone Road, MS 6511, Tallahassee, FL 32399-2400. Water quality data associated with extreme climatic conditions, such as floods, droughts, and hurricanes, shall be excluded from the analysis.

3. Demonstration of downstream protection by one of the following methods:

a. Downstream waters are attaining water quality standards related to nutrient conditions pursuant to Chapter 62-303, F.A.C.; or

b. If the downstream waters do not attain water quality standards related to nutrient conditions:

i. The nutrients delivered by the waterbody subject to the Type III SSAC meet the allocations of a downstream TMDL; or

ii. The nutrients delivered by the waterbody are shown to provide for the attainment and maintenance of water quality standards in downstream waters.

(b) The SSAC shall be established at a level representative of nutrient loads or concentrations that have been demonstrated to be protective of the designated use by maintaining balanced, natural populations of aquatic flora and fauna. This demonstration shall take into account natural variability by using statistical methods appropriate to the data set, as described in *Development of Type III Site Specific Alternative Criteria (SSAC) for Nutrients* (DEP-SAS-004/11).

(3) through (4) renumber (4) through (5) No change.

(6) ~~(5)~~ Type II s~~S~~ite specific alternative criteria apply to the water bodies, or portions of the water bodies, listed below. For dissolved oxygen site specific alternative criteria, normal daily and seasonal fluctuations above the levels listed in the table below shall be maintained. For site specific alternative criteria with seasonal limits, the generally applicable criteria in Rule 62-302.530, F.A.C., apply at other times of the year.

(a) through (d) No change.

Rulemaking Authority 403.061, 403.062, 403.087, 403.504, 403.704, 403.804, 403.805 FS. Law Implemented 403.021, 403.061, 403.087, 403.088, 403.141, 403.161, 403.502 FS. History–Formerly 17-3.05(4), Amended 3-1-79, 10-2-80, 2-1-83, Formerly 17-3.031, Amended 6-17-92, Formerly 17-302.800, Amended 5-15-02, 1-9-06, 6-28-06, 12-7-06, 8-5-07, 8-5-10, - -11.

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Part III

Environmental Protection Agency

40 CFR Part 131

Water Quality Standards for the State of Florida's Lakes and Flowing Waters; Final Rule

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 16
PARTY Florida Power & Light Co.
DESCRIPTION R.R. LaBauve (RRL-10), 40CFR, part 131,
DATE Stand. for FL Lakes and Flowing Waters (EPA)

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 131

[EPA–HQ–OW–2009–0596; FRL–9228–7]

RIN 2040–AF11

Water Quality Standards for the State of Florida's Lakes and Flowing Waters

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA or Agency) is promulgating numeric water quality criteria for nitrogen/phosphorus pollution to protect aquatic life in lakes, flowing waters, and springs within the State of Florida. These criteria apply to Florida waters that are designated as Class I or Class III waters in order to implement the State's narrative nutrient provision at Subsection 62–302–530(47)(b), Florida Administrative Code (F.A.C.), which provides that "[i]n no case shall nutrient concentrations of a body of water be altered so as to cause an imbalance in natural populations of aquatic flora or fauna."

DATES: This final rule is effective March 6, 2012, except for 40 CFR 131.43(e), which is effective February 4, 2011.

ADDRESSES: An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.regulations.gov* to view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.* Although listed in the index, some information is not publicly available, *i.e.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyright material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Docket Facility. The Office of Water (OW) Docket Center is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The OW Docket Center telephone number is 202–566–1744 and the Docket address is OW Docket, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744.

FOR FURTHER INFORMATION CONTACT: For information concerning this rulemaking, contact Danielle Salvaterra, U.S. EPA Headquarters, Office of Water, Mailcode: 4305T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: 202–564–1649; fax number: 202–566–9981; e-mail address: *salvaterra.danielle@epa.gov.*

SUPPLEMENTARY INFORMATION: This supplementary information section is organized as follows:

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I. General Information

A. Executive Summary

Florida is known for its abundant and aesthetically beautiful natural resources, in particular its water resources. Florida's water resources are very important to its economy, for example, its $6.5 billion fishing industry.[1] However, nitrogen/phosphorus pollution has contributed to severe water quality degradation in the State of Florida. Based upon waters assessed and reported by the Florida Department of Environmental Protection (FDEP) in its *2008 Integrated Water Quality Assessment for Florida,* approximately 1,049 miles of rivers and streams (about 5% of total assessed streams), 349,248 acres of lakes (about 23% of total assessed lakes), and 902 square miles of estuaries (about 24% of total assessed estuaries) are known to be impaired for nutrients by the State.[2]

The information presented in FDEP's latest water quality assessment report, the *2010 Integrated Water Quality Assessment for Florida,* documents increased identification of assessed waters that are impaired due to nutrients. In the FDEP *2010 Integrated Water Quality Assessment for Florida,* approximately 1,918 miles of rivers and streams (about 8% of assessed river and stream miles), 378,435 acres of lakes (about 26% of assessed lake acres), and 569 square miles of estuaries[3] (about 21% of assessed square miles of estuaries)[4] are identified as impaired by

[1] Florida Fish and Wildlife Conservation Commission. 2010. *The economic impact of freshwater fishing in Florida. http://www.myfwc.com/CONSERVATION/Conservation_ValueofConservation_EconFreshwaterImpact.htm.* Accessed August 2010.

[2] Florida Department of Environmental Protection (FDEP). 2008. Integrated Water Quality Assessment for Florida: 2008 305(b) Report and 303(d) List Update.

[3] The estimated miles for estuaries were recalculated in 2010. FDEP used revised GIS techniques to calculate mileages and corrected estuary waterbody descriptions by removing land drainage areas that had been included in some descriptions, which reduced the estimates of total estuarine water area for Florida waters generally, as well as for some of the estuary classifications in the 2010 report.

[4] For the Integrated Water Quality Assessment for Florida: 2010 305(b) Report and 303(d) List Update, Florida assessed about 3,637 additional miles of streams, about 24,833 fewer acres of lakes, and about 1,065 fewer square miles of estuaries than the 2008 Integrated Report. In addition, Florida reevaluated the WBID segment boundaries using "improved GIS techniques" for mapping. The most significant result of the major change in mapping was the reduction of assessed estuarine area from 3,726 to 2,661 square miles. The net result to the impaired waters for estuaries is that the percent of

nutrients.[5] The challenge of nitrogen/phosphorus pollution has been an ongoing focus for FDEP. Over the past decade or more, FDEP reports that it has spent over 20 million dollars collecting and analyzing data related to concentrations and impacts of nitrogen/phosphorus pollution in the State.[6] Despite FDEP's intensive efforts to diagnose and evaluate nitrogen/phosphorus pollution, substantial and widespread water quality degradation from nitrogen/phosphorus over-enrichment has continued and remains a significant problem.

On January 14, 2009, EPA determined under Clean Water Act (CWA) section 303(c)(4)(B) that new or revised water quality standards (WQS) in the form of numeric water quality criteria are necessary to protect the designated uses from nitrogen/phosphorus pollution that Florida has set for its Class I and Class III waters. The Agency considered (1) the State's documented unique and threatened ecosystems, (2) the large number of impaired waters due to existing nitrogen/phosphorus pollution, and (3) the challenge associated with growing nitrogen/phosphorus pollution associated with expanding urbanization, continued agricultural development, and a significantly increasing population that the U.S. Census estimates is expected to grow over 75% between 2000 and 2030.[7] EPA also reviewed the State's regulatory accountability system, which represents a synthesis of both technology-based standards and point source control authority, as well as authority to establish enforceable controls for nonpoint source activities.

A significant challenge faced by Florida's water quality program is its dependence and current reliance upon an approach involving resource-intensive and time-consuming site-by-site data collection and analysis to interpret non-numeric narrative criteria. This approach is used to make water quality impairment determinations under CWA section 303(d), to set appropriately protective numeric nitrogen and phosphorus pollution targets to guide restoration of impaired waters, and to establish numeric nitrogen and phosphorus goals to ensure effective protection and maintenance of non-impaired waters. EPA determined that Florida's reliance on a case-by-case interpretation of its narrative criterion in implementing an otherwise comprehensive water quality framework of enforceable accountability mechanisms was insufficient to ensure protection of applicable designated uses under Subsection 62–302.530(47)(b), F.A.C., which, as noted above, provides "[i]n no case shall nutrient concentrations of a body of water be altered so as to cause an imbalance in natural populations of aquatic flora or fauna."

In accordance with the terms of EPA's January 14, 2009 determination, an August 2009 Consent Decree, and June 7, 2010 and October 27, 2010 revisions to that Consent Decree, which are discussed in more detail in Section II.D, EPA is promulgating and establishing final numeric criteria for lakes and springs throughout Florida, and flowing waters (*e.g.*, rivers, streams, canals, *etc.*) located outside of the South Florida Region.[8]

Regarding numeric criteria for streams, the Agency conducted a detailed technical evaluation of the substantial amount of sampling, monitoring and associated water quality analytic data available on Florida streams together with a significant amount of related scientific analysis. EPA concluded that reliance on a reference-based methodology was a strong and scientifically sound approach for deriving numeric criteria, in the form of total nitrogen (TN) and total phosphorus (TP) concentration values for flowing waters including streams and rivers. This information is presented in more detail in Section III.B below.

For lakes, EPA is promulgating a classification approach using color and alkalinity based upon substantial data that show that lake color and alkalinity are important predictors of the degree to which TN and TP concentrations result in a biological response such as elevated chlorophyll *a* levels. EPA found that correlations between nitrogen/phosphorus and biological response parameters in the different types of lakes in Florida were specific, significant, and documentable, and when considered in combination with additional lines of evidence, support a stressor-response approach to criteria development for Florida's lakes. EPA's results show a significant relationship between concentrations of nitrogen and phosphorus in lakes and algal growth. The Agency is also promulgating an accompanying supplementary analytical approach that the State can use to adjust TN and TP criteria within a certain range for individual lakes where sufficient data on long-term ambient chlorophyll *a*, TN, and TP levels are available to demonstrate that protective chlorophyll *a* criterion for a specific lake will still be maintained and attainment of the designated use will be assured. This information is presented in more detail in Section III.C below.

EPA also evaluated what downstream protection criteria for streams that flow into lakes is necessary for assuring the protection of downstream lake water quality pursuant to the provisions of 40 CFR 130.10(b), which requires that water quality standards (WQS) must provide for the attainment and maintenance of the WQS of downstream waters. EPA examined a variety of lake modeling techniques and data to ensure protection of aquatic life in downstream lakes that have streams flowing into them. Accordingly, this final rule includes a tiered approach to adjust instream TP and TN criteria for flowing waters to ensure protection of downstream lakes. This approach is detailed in Section III.C(2)(f) below.[9]

Regarding numeric criteria for springs, EPA is promulgating a nitrate+nitrite criterion for springs based on stressor-response relationships that are based on laboratory data and field evaluations that document the response of nuisance[10] algae and periphyton growth to nitrate+nitrite concentrations in springs. This criterion is explained in more detail in Section III.D below.

Finally, EPA is promulgating in this notice an approach to authorize and allow derivation of Federal site-specific alternative criteria (SSAC) based upon EPA review and approval of applicant submissions of scientifically defensible

assessed estuaries impaired remains about the same in 2008 (24%) as in 2010 (21%).

[5] FDEP. 2010. Integrated Water Quality Assessment for Florida: 2010 305(b) Report and 303(d) List Update.

[6] FDEP. 2009. Florida Numeric Nutrient Criteria History and Status. *http://www.dep.state.fl.us/water/wqssp/nutrients/docs/fl-nnc-summary-100109.pdf.* Accessed September 2010.

[7] U.S. Census Bureau, Population Division, Interim State Population Projections, 2005. *http://www.census.gov/population/projections/SummaryTabA1.pdf.*

[8] For purposes of this rule, EPA has distinguished South Florida as those areas south of Lake Okeechobee and the Caloosahatchee River watershed to the west of Lake Okeechobee and the St. Lucie watershed to the east of Lake Okeechobee, hereinafter referred to as the South Florida Region. Numeric criteria applicable to flowing waters in the South Florida Region will be addressed in the second phase of EPA's rulemaking regarding the establishment of estuarine and coastal numeric criteria. (Please refer to Section I.B for a discussion of the water bodies affected by this rule).

[9] As provided by the terms of the June 7, 2010 amended Consent Decree, downstream protection values for estuaries and coastal waters will be addressed in the context of the second phase of this rulemaking process.

[10] Nuisance algae is best characterized by Subsection 62–302.200(17), F.A.C.: "Nuisance Species" shall mean species of flora or fauna whose noxious characteristics or presence in sufficient number, biomass, or areal extent may reasonably be expected to prevent, or unreasonably interfere with, a designated use of those waters.

recalculations that meet the requirements of CWA section 303(c) and EPA's implementing regulations at 40 CFR part 131. Total maximum daily load (TMDL) targets submitted to EPA for consideration as new or revised WQS would be reviewed under this SSAC process. This approach is discussed in more detail in Section V.C below.

Throughout the development of this rulemaking, EPA has emphasized the importance of sound science and widespread input in developing numeric criteria. Stakeholders have reiterated that numeric criteria must be scientifically sound. As demonstrated by the extent and detail of scientific analysis explained below, EPA continues to strongly agree. Under the CWA and EPA's implementing regulations, numeric criteria must protect the designated use of a waterbody (as well as ensure protection of downstream uses) and must be based on sound scientific rationale. (*See* CWA section 303(c); 40 CFR 131.11). In Florida, EPA relied upon its published criteria development methodologies [11] and a substantial body of scientific analysis, documentation, and evaluation, much of it provided to EPA by FDEP. As discussed in more detail below, EPA believes that the final criteria in this rule meet requirements for designated use and downstream WQS protection under the CWA and that they are clearly based on sound and substantial data and analyses.

B. Which water bodies are affected by this rule?

The criteria in this final rulemaking apply to a group of inland waters of the United States within Florida. Specifically, as defined below, these criteria apply to lakes and springs throughout Florida, and flowing waters (*e.g.*, rivers, streams, canals, *etc.*) located outside of the South Florida Region. For purposes of this rule, EPA has distinguished South Florida as those areas south of Lake Okeechobee and the Caloosahatchee River watershed to the west of Lake Okeechobee and the St. Lucie watershed to the east of Lake Okeechobee, hereinafter referred to as the South Florida Region. In this section, EPA defines the water bodies affected by this rule with respect to the Clean Water Act, Florida Administrative Code, and geographic scope in Florida. Because this regulation applies to inland waters, EPA defines fresh water as it applies to the affected water bodies.

The CWA requires adoption of WQS for "navigable waters." CWA section 303(c)(2)(A). The CWA defines "navigable waters" to mean "the waters of the United States, including the territorial seas." CWA section 502(7). Whether a particular waterbody is a water of the United States is a waterbody-specific determination. Every waterbody that is a water of the United States requires WQS under the CWA. EPA is not aware of any waters of the United States in Florida that are currently exempted from the State's WQS. For any privately-owned water in Florida that is a water of the United States, the applicable numeric criteria for those types of waters would apply. This rule does not apply to waters for which the Miccosukee Tribe of Indians or Seminole Tribe of Indians has obtained Treatment in the Same Manner as a State status for Sections 303 and 401 of the CWA, pursuant to Section 518 of the CWA.

EPA's final rule defines "lakes and flowing waters" (a phrase that includes lakes, streams, and springs) to mean inland surface waters that have been classified as Class I (Potable Water Supplies) or Class III (Recreation, Propagation and Maintenance of a Healthy, Well-Balanced Population of Fish and Wildlife) water bodies pursuant to Section 62–302.400, F.A.C., which are predominantly fresh waters, excluding wetlands. Class I and Class III surface waters share water quality criteria established to "protect recreation and the propagation and maintenance of a healthy, well-balanced population of fish and wildlife" pursuant to Subsection 62–302.400(4), F.A.C.[12]

Geographically, the regulation applies to all lakes and springs throughout Florida. EPA is not finalizing numeric criteria for Florida's streams or canals in south Florida at this time. As noted above, EPA has distinguished South Florida as those areas south of Lake Okeechobee and the Caloosahatchee River watershed to the west of Lake Okeechobee and the St. Lucie watershed to the east of Lake Okeechobee, hereinafter referred to as the South Florida Region. The Agency will propose criteria for south Florida flowing waters in conjunction with criteria for Florida's estuarine and coastal waters by November 14, 2011.

Consistent with Section 62–302.200, F.A.C., EPA's final rule defines "predominantly fresh waters" to mean surface waters in which the chloride concentration at the surface is less than 1,500 milligrams per liter (mg/L). Consistent with Section 62–302.200, F.A.C., EPA's final rule defines "surface water" to mean "water upon the surface of the earth, whether contained in bounds created naturally, artificially, or diffused. Water from natural springs shall be classified as surface water when it exits from the spring onto the earth's surface." In this rulemaking, EPA is promulgating numeric criteria for the following waterbody types: lakes, streams, and springs. EPA's final rule also includes definitions for each of these waters. "Lake" means a slow-moving or standing body of freshwater that occupies an inland basin that is not a stream, spring, or wetland. "Stream" means a free-flowing, predominantly fresh surface water in a defined channel, and includes rivers, creeks, branches, canals, freshwater sloughs, and other similar water bodies. "Spring" means a site at which ground water flows through a natural opening in the ground onto the land surface or into a body of surface water. Consistent with Section 62–312.020, F.A.C., "canal" means a trench, the bottom of which is normally covered by water with the upper edges of its two sides normally above water.

C. What entities may be affected by this rule?

Citizens concerned with water quality in Florida may be interested in this rulemaking. Entities discharging nitrogen or phosphorus to lakes and flowing waters of Florida could be indirectly affected by this rulemaking because WQS are used in determining National Pollutant Discharge Elimination System (NPDES) permit limits. Categories and entities that may ultimately be affected include:

[11] USEPA. 2000a. *Nutrient Criteria Technical Guidance Manual: Lakes and Reservoirs.* EPA–822–B–00–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC. USEPA. 2000b. *Nutrient Criteria Technical Guidance Manual: Rivers and Streams.* EPA–822–B–00–002. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[12] Class I waters also include an applicable nitrate limit of 10 mg/L and nitrite limit of 1 mg/L for the protection of human health in drinking water supplies. The nitrate limit applies at the entry point to the distribution system (*i.e.*, after any treatment); *see* Chapter 62–550, F.A.C., for additional details.

Category	Examples of potentially affected entities
Industry	Industries discharging pollutants to lakes and flowing waters in the State of Florida.
Municipalities	Publicly-owned treatment works discharging pollutants to lakes and flowing waters in the State of Florida.
Stormwater Management Districts	Entities responsible for managing stormwater runoff in Florida.

This table is not intended to be exhaustive, but rather provides a guide for entities that may be directly or indirectly affected by this action. This table lists the types of entities of which EPA is now aware that potentially could be affected by this action. Other types of entities not listed in the table, such as nonpoint source contributors to nitrogen/phosphorus pollution in Florida's waters may be affected through implementation of Florida's water quality standards program (*i.e.*, through Basin Management Action Plans (BMAPs)). Any parties or entities conducting activities within watersheds of the Florida waters covered by this rule, or who rely on, depend upon, influence, or contribute to the water quality of the lakes and flowing waters of Florida, may be affected by this rule. To determine whether your facility or activities may be affected by this action, you should carefully examine the language in 40 CFR 131.43, which is the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

D. How can I get copies of this document and other related information?

1. *Docket.* EPA has established an official public docket for this action under Docket Id. No. EPA–HQ–OW–2009–0596. The official public docket consists of the document specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include CBI or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the OW Docket, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is 202–566–2426. A reasonable fee will be charged for copies.

2. *Electronic Access.* You may access this **Federal Register** document electronically through the EPA Internet under the "Federal Register" listings at *http://www.epa.gov/fedrgstr/.*

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.regulations.gov* to view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.* Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the Docket Facility identified in Section I.C(1).

II. Background

A. Nitrogen/Phosphorus Pollution

1. What is nitrogen/phosphorus pollution?

Excess loading of nitrogen and phosphorus compounds,[13] is one of the most prevalent causes of water quality impairment in the United States. Nitrogen/phosphorus pollution problems have been recognized for some time in the U.S., for example a 1969 report by the National Academy of Sciences [14] notes "[t]he pollution problem is critical because of increased population, industrial growth, intensification of agricultural production, river-basin development, recreational use of waters, and domestic and industrial exploitation of shore properties. Accelerated eutrophication causes changes in plant and animal life—changes that often interfere with use of water, detract from natural beauty, and reduce property values." Inputs of nitrogen and phosphorus lead to over-enrichment in many of the Nation's waters and constitute a widespread, persistent, and growing problem. Nitrogen/phosphorus pollution in fresh water systems can significantly impact aquatic life and long-term ecosystem health, diversity, and balance. More specifically, high nitrogen and phosphorus loadings result in harmful algal blooms (HABs), reduced spawning grounds and nursery habitats, fish kills, and oxygen-starved hypoxic or "dead" zones. Public health concerns related to nitrogen/phosphorus pollution include impaired surface and groundwater drinking water sources from high levels of nitrates, possible formation of disinfection byproducts in drinking water, and increased exposure to toxic microbes such as cyanobacteria.[15] [16] Degradation of water bodies from nitrogen/phosphorus pollution can result in economic consequences. For example, given that fresh and salt water fishing in Florida are significant recreational and tourist attractions generating over six billion dollars annually,[17] changes in Florida's waters that degrade water quality to the point that sport fishing populations are affected, will also affect this important part of Florida's economy. Elevated nitrogen/phosphorus levels can occur locally in a stream or groundwater, or can accumulate much further downstream leading to degraded lakes, reservoirs, and estuaries where fish and aquatic life can no longer survive.

Excess nitrogen/phosphorus in water bodies comes from many sources, which can be grouped into five major categories: (1) Urban stormwater runoff—sources associated with urban land use and development, (2) municipal and industrial waste water discharges, (3) row crop agriculture, (4) livestock production, and (5) atmospheric deposition from the production of nitrogen oxides in electric

[13] To be used by living organisms, nitrogen gas must be fixed into its reactive forms; for plants, either nitrate or ammonia (Boyd, C.E. 1979. *Water Quality in Warmwater Fish Ponds.* Auburn University: Alabama Agricultural Experiment Station, Auburn, AL). Eutrophication is defined as the natural or artificial addition of nitrogen/phosphorus to bodies of water and to the effects of added nitrogen/phosphorus (National Academy of Sciences (U.S.). 1969. *Eutrophication: Causes, Consequences, Correctives.* National Academy of Sciences, Washington, DC.)

[14] National Academy of Sciences (U.S.). 1969. *Eutrophication: Causes, Consequences, Correctives.* National Academy of Sciences, Washington, DC.

[15] Villanueva, C.M. *et al.*, 2006. Bladder Cancer and Exposure to Water Disinfection By-Products through Ingestion, Bathing, Showering, and Swimming in Pools. *American Journal of Epidemiology* 165(2):148–158.

[16] USEPA. 2009. *What Is in Our Drinking Water?.* United States Environmental Protection Agency, Office of Research and Development. *http://www.epa.gov/extramurl/research/process/drinkingwater.html.* Accessed December 2009.

[17] Florida Fish and Wildlife Conservation Commission. 2010. *The economic impact of freshwater fishing in Florida. http://www.myfwc.com/CONSERVATION/Conservation_Valueof Conservation_EconFreshwaterImpact.htm.* Accessed August 2010.

power generation and internal combustion engines. These sources contribute significant loadings of nitrogen and phosphorus to surface waters, causing major impacts to aquatic ecosystems and significant imbalances in the natural populations of flora and fauna.[18] [19]

2. Adverse Impacts of Nitrogen/Phosphorus Pollution on Aquatic Life, Human Health, and the Economy

Fish, shellfish, and wildlife require clean water for survival. Changes in the environment resulting from elevated nitrogen/phosphorus levels (such as algal blooms, toxins from harmful algal blooms, and hypoxia/anoxia) can cause a variety of effects. The causal pathways that lead from human activities to excess nutrients to impacts on designated uses in lakes and streams are well established in the scientific literature (*e.g.*, Streams: Stockner and Shortreed 1976, Stockner and Shortreed 1978, Elwood *et al.* 1981, Horner *et al.* 1983, Bothwell 1985, Peterson *et al.* 1985, Moss *et al.* 1989, Dodds and Gudder 1992, Rosemond *et al.* 1993, Bowling and Baker 1996, Bourassa and Cattaneo 1998, Francoeur 2001, Biggs 2000, Rosemond *et al.* 2001, Rosemond *et al.* 2002, Slavik *et al.* 2004, Cross *et al.* 2006, Mulholland and Webster 2010; Lakes: Vollenweider 1968, NAS 1969, Schindler *et al.* 1973, Schindler 1974, Vollenweider 1976, Carlson 1977, Paerl 1988, Elser *et al.* 1990, Smith *et al.* 1999, Downing *et al.* 2001, Smith *et al.* 2006, Elser *et al.* 2007).[20]

When excessive nitrogen/phosphorus loads change a waterbody's algae and plant species, the change in habitat and available food resources can induce changes affecting an entire food chain. Algal blooms block sunlight that submerged grasses need to grow, leading to a decline of submerged aquatic vegetation beds and decreased habitat for juvenile organisms. Algal blooms can also increase turbidity and impair the ability of fish and other aquatic life to find food.[21] Algae can also damage or clog the gills of fish and invertebrates.[22] Excessive algal blooms (those that use oxygen for respiration during periods without sunlight) can lead to diurnal shifts in a waterbody's production and consumption of dissolved oxygen (DO) resulting in reduced DO levels that are sufficiently low to harm or kill important recreational species such as largemouth bass.

Excessive algal growth also contributes to increased oxygen consumption associated with decomposition (*e.g.* decaying vegetative matter), in many instances reducing

[18] National Research Council. 2000. *Clean coastal waters: Understanding and reducing the effects of nutrient pollution.* National Academies Press, Washington, DC; Howarth, R.W., A. Sharpley, and D. Walker. 2002. Sources of nutrient pollution to coastal waters in the United States: Implications for achieving coastal water quality goals. *Estuaries* 25(4b):656–676; Smith, V.H. 2003. Eutrophication of freshwater and coastal marine ecosystems. *Environmental Science and Pollution Research* 10(2):126–139; Dodds, W.K., W.W. Bouska, J.L. Eitzmann, T.J. Pilger, K.L. Pitts, A.J. Riley, J.T. Schloesser, and D.J. Thornbrugh. 2009. Eutrophication of U.S. freshwaters: Analysis of potential economic damages. *Environmental Science and Technology* 43(1):12–19.

[19] State-EPA Nutrient Innovations Task Group. 2009. *An Urgent Call to Action: Report of the State-EPA Nutrient Innovations Task Group.*

[20] For Streams:

Stockner, J.G., and K.R.S. Shortreed. 1976. Autotrophic production in Carnation Creek, a coastal rainforest stream on Vancouver Island, British Columbia. *Journal of the Fisheries Research Board of Canada* 33:1553–1563.;

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Horner, R.R., E.B. Welch, and R.B. Veenstra. 1983. Development of nuisance periphytic algae in laboratory streams in relation to enrichment and velocity. Pages 121–134 in R.G. Wetzel (editor). *Periphyton of freshwater ecosystems.* Dr. W. Junk Publishers, The Hague, The Netherlands.;

Bothwell, M.L. 1985. Phosphorus limitation of lotic periphyton growth rates: an intersite comparison using continuous-flow troughs (Thompson River system, British Columbia). *Limnology and Oceanography* 30:527–542.;

Peterson, B.J., J.E. Hobbie, A.E. Hershey, M.A. Lock, T.E. Ford, J.R. Vestal, V.L. McKinley, M.A.J. Hullar, M.C. Miller, R.M. Ventullo, and G.S. Volk. 1985. Transformation of a tundra river from heterotrophy to autotrophy by addition of phosphorus. *Science* 229:1383–1386.;

Moss, B., I. Hooker, H. Balls, and K. Manson. 1989. Phytoplankton distribution in a temperate floodplain lake and river system. I. Hydrology, nutrient sources and phytoplankton biomass. *Journal of Plankton Research* 11:813–835.;

Dodds, W.K., and D.A. Gudder. 1992. The ecology of Cladophora. *Journal of Phycology* 28:415–427.;

Rosemond, A. D., P. J. Mulholland, and J. W. Elwood. 1993. Top-down and bottom-up control of stream periphyton: Effects of nutrients and herbivores. *Ecology* 74:1264–1280.;

Bowling, L.C., and P.D. Baker. 1996. Major cyanobacterial bloom in the Barwon-Darling River, Australia, in 1991, and underlying limnological conditions. *Marine and Freshwater Research* 47: 643–657.;

Bourassa, N., and A. Cattaneo. 1998. Control of periphyton biomass in Laurentian streams (Quebec). *Journal of the North American Benthological Society* 17:420–429.;

Francoeur, S.N. 2001. Meta-analysis of lotic nutrient amendment experiments: detecting and quantifying subtle responses. *Journal of the North American Benthological Society* 20:358–368.;

Biggs, B.J.F. 2000. Eutrophication of streams and rivers: dissolved nutrient-chlorophyll relationships for Benthic algae. *Journal of the North American Benthological Society* 19:17–31.;

Rosemond, A.D., C.M. Pringle, A. Ramirez, and M.J. Paul. 2001. A test of top-down and bottom-up control in a detritus-based food web. *Ecology* 82: 2279–2293.;

Rosemond, A.D., C.M. Pringle, A. Ramirez, M.J. Paul, and J.L. Meyer. 2002. Landscape variation in phosphorus concentration and effects on detritus-based tropical streams. *Limnology and Oceanography* 47:278–289.;

Slavik, K., B.J. Peterson, L.A. Deegan, W.B. Bowden, A.E. Hershey, and J.E. Hobbie. 2004. Long-term responses of the Kuparuk River ecosystem to phosphorus fertilization. *Ecology* 85:939—954.;

Cross, W.F., J.B. Wallace, A.D. Rosemond, and S.L. Eggert. 2006. Whole-system nutrient enrichment Increases secondary production in a detritus-based ecoystem. *Ecology* 87:1556–1565.;

Mulholland, P.J. and J.R. Webster. 2010. Nutrient dynamics in streams and the role of J–NABS. *Journal of the North American Benthological Society* 29:100–117.;

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Vollenweider, R.A. 1968. *Scientific Fundamentals of the Eutrophication of Lakes and Flowing Waters, With Particular Reference to Nitrogen and Phosphorus as Factors in Eutrophication* (Tech Rep DAS/CS/68.27, OECD, Paris).;

National Academy of Science. 1969. *Eutrophication: Causes, Consequences, Correctives.* National Academy of Science, Washington, DC.;

Schindler D.W., H. Kling, R.V. Schmidt, J. Prokopowich, V.E. Frost, R.A. Reid, and M. Capel. 1973. Eutrophication of Lake 227 by addition of phosphate and nitrate: The second, third, and fourth years of enrichment 1970, 1971, and 1972. *Journal of the Fishery Research Board of Canada* 30:1415–1440.;

Schindler D.W. 1974. Eutrophication and recovery in experimental lakes: Implications for lake management. *Science* 184:897–899.;

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Paerl, H.W. 1988. Nuisance phytoplankton blooms in coastal, estuarine, and inland waters. *Limnology and Oceanography* 33:823–847.;

Elser, J.J., E.R. Marzolf, and C.R. Goldman. 1990. Phosphorus and nitrogen limitation of phytoplankton growth in the freshwaters of North America: a review and critique of experimental enrichments. *Canadian Journal of Fisheries and Aquatic Science* 47:1468–1477.;

Smith, V.H., G.D. Tilman, and J.C. Nekola. 1999. Eutrophication: impacts of excess nutrient inputs on freshwater, marine, and terrestrial ecosystems. *Environmental Pollution* 100:179–196.;

Downing, J.A., S.B. Watson, and E. McCauley. 2001. Predicting cyanobacteria dominance in lakes. *Canadian Journal of Fisheries and Aquatic Sciences* 58:1905–1908.;

Smith, V.H., S.B. Joye, and R.W. Howarth. 2006. Eutrophication of freshwater and marine ecosystems. *Limnology and Oceanography* 51:351–355.;

Elser, J.J., M.E.S. Bracken, E.E. Cleland, D.S. Gruner, W.S. Harpole, H. Hillebrand, J.T. Ngai, E.W. Seabloom, J.B. Shurin, and J.E. Smith. 2007. Global analysis of nitrogen and phosphorus limitation of primary production in freshwater, marine, and terrestrial ecosystems. *Ecology Letters* 10:1135–1142.

[21] Hauxwell, J., C. Jacoby, T. Frazer, and J. Stevely. 2001. *Nutrients and Florida's Coastal Waters:* Florida Sea Grant Report No. SGEB–55. Florida Sea Grant College Program, University of Florida, Gainesville, FL.

[22] NOAA. 2009. Harmful Algal Blooms: Current Programs Overview. National Oceanic and Atmospheric Administration. *http://www.cop.noaa.gov/stressors/extremeevents/hab/default.aspx.* Accessed December 2009.

oxygen to levels below that needed for aquatic life to survive and flourish.[23] [24] Mobile species, such as adult fish, can sometimes survive by moving to areas with more oxygen. However, migration to avoid hypoxia depends on species mobility, availability of suitable habitat, and adequate environmental cues for migration. Less mobile or immobile species, such as mussels, cannot move to avoid low oxygen and are often killed during hypoxic events.[25] While certain mature aquatic animals can tolerate a range of dissolved oxygen levels that occur in the water, younger life stages of species like fish and shellfish often require higher levels of oxygen to survive.[26] Sustained low levels of dissolved oxygen cause a severe decrease in the amount of aquatic life in hypoxic zones and affect the ability of aquatic organisms to find necessary food and habitat.

In freshwater, HABs including, for example, blue-green algae from the phylum of bacteria called cyanobacteria,[27] can produce toxins that have been implicated as the cause of a number of fish and bird mortalities.[28] These toxins have also been tied to the death of pets and livestock that may be exposed through drinking contaminated water or grooming themselves after bodily exposure.[29] Many other States, and countries for that matter, are experiencing problems with algal blooms.[30] Ohio on September 3, 2010,[31] for example, listed eight water bodies as "Bloom Advisory," [32] six water bodies as "Toxin Advisory," [33] and two waters as "No Contact Advisory." [34] Species of cyanobacteria associated with freshwater algal blooms include: *Microcystis aeruginosa, Anabaena circinalis, Anabaena flos-aquae, Aphanizomenon flos-aquae,* and *Cylindrospermopsis raciborskii.* The toxins from cyanobacterial harmful algal blooms can produce neurotoxins (affect the nervous system), hepatotoxins (affect the liver), produce lipopolysaccharides that affect the gastrointestinal system, and some are tumor promoters.[35] A recent study showed that at least one type of cyanobacteria has been linked to cancer and tumor growth in animals.[36] Cyanobacteria toxins can also pass through normal drinking water treatment processes and pose an increased risk to humans or animals.[37]

Health and recreational use impacts to humans result directly from exposure to elevated nitrogen/phosphorus pollution levels and indirectly from the subsequent waterbody changes that occur from increased nitrogen/phosphorus pollution (such as algal blooms and toxins). Direct impacts include effects to human health through potentially contaminated drinking water. Indirect impacts include restrictions on recreation (such as boating and swimming). Algal blooms can prevent opportunities to swim and engage in other types of recreation. In areas where recreation is determined to be unsafe because of algal blooms, warning signs are often posted to discourage human use of the waters.

Nitrate in drinking water can cause serious health problems for humans,[38] especially infants. EPA developed a Maximum Contaminant Level (MCL) of 10 mg/L for nitrate in drinking water.[39] In the 2010 USGS National Water-Quality Assessment Program report, nitrate was found to be the most frequently detected nutrient in streams at concentrations greater than 10 mg/L. The report also found that concentrations of nitrate greater than the MCL of 10 mg/L were more prevalent and widespread in groundwater used for drinking water than in streams.[40] Florida has adopted EPA's recommendations for the nitrate MCL in Florida's regulated drinking water systems and a 10 mg/L criteria for nitrate in Class I waters. FDEP shares EPA's concern regarding blue-baby syndrome as can be seen in information FDEP reports on its drinking water information for the public: "Nitrate is used in fertilizer and is found in sewage and wastes from human and/or farm animals and generally gets into drinking water from those activities. Excessive levels of nitrate in drinking water have caused serious illness and sometimes death in infants less than six months of age [41] * * * EPA has set the drinking water standard at 10 parts per million (ppm) [or 10 mg/L] for nitrate to protect

[23] NOAA. 2009. Harmful Algal Blooms: Current Programs Overview. National Oceanic and Atmospheric Administration. *http://www.cop.noaa.gov/stressors/extremeevents/hab/default.aspx.* Accessed December 2009.

[24] USGS. 2009. *Hypoxia.* U.S. Geological Survey. *http://toxics.usgs.gov/definitions/hypoxia.html.* Accessed December 2009.

[25] ESA. 2009. *Hypoxia.* Ecological Society of America. *http://www.esa.org/education_diversity/pdfDocs/hypoxia.pdf.* Accessed December 2009.

[26] USEPA. 1986. *Ambient Water Quality Criteria for Dissolved Oxygen Freshwater Aquatic Life.* EPA–800–R–80–906. Environmental Protection Agency, Office of Water, Washington DC.

[27] CDC. 2010. *Facts about cyanobacteria and cyanobacterial harmful algal blooms. Centers for Disease Control and Prevention. http://www.cdc.gov/hab/cyanobacteria/facts.htm.* Accessed August 2010.

[28] Ibelings, Bas W. and Karl E. Havens. 2008 *Chapter 32: Cyanobacterial toxins: a qualitative meta-analysis of concentrations, dosage and effects in freshwater, estuarine and marine biota. In* Cyanobacterial Harmful Algal Blooms: State of the Science and Research Needs. From the Monograph of the September 6–10, 2005 International Symposium on Cyanobacterial Harmful Algal Blooms (ISOC–HAB) in Durham, NC. *http://www.epa.gov/cyano_habs_symposium/monograph/Ch32.pdf.* Accessed August 19, 2010.

[29] WHOI. 2008. *HAB Impacts on Wildlife.* Woods Hole Oceanographic Institution. *http://www.whoi.edu/redtide/page.do?pid=9682.* Accessed December 2009.

[30] FDEP. 2010. Blue Green Algae Frequently Asked Questions. *http://www.dep.state.fl.us/water/bgalgae/faq.htm.* Accessed August 2010.

[31] Ohio DNR. 2010. News Release September 3, 2010. *http://www.epa.state.oh.us/portals/47/nr/2010/september/9-3samplingresults.pdf.* Accessed September 2010.

[32] Defined as: Cautionary advisory to avoid contact with any algae. Ohio DNR. 2010. News Release September 3, 2010. *http://www.epa.state.oh.us/portals/47/nr/2010/september/9-3samplingresults.pdf.* Accessed September 2010.

[33] Defined as: Avoid contact with any algae and direct contact with water. Ohio DNR. 2010. News Release September 3, 2010. *http://www.epa.state.oh.us/portals/47/nr/2010/september/9-3samplingresults.pdf.* Accessed September 2010.

[34] Defined as: Avoid any and all contact with or ingestion of the lake water. This includes the launching of any watercraft on the lake. Ohio DNR. 2010. News Release September 3, 2010. *http://www.epa.state.oh.us/portals/47/nr/2010/september/9-3samplingresults.pdf.* Accessed September 2010.

[35] CDC. 2010. Facts about cyanobacteria and cyanobacterial harmful algal blooms, Centers for Disease Control and Prevention. *http://www.cdc.gov/hab/cyanobacteria/facts.htm.* Accessed August 2010.

[36] Falconer, I.R., and A.R. Humpage. 2005. Health Risk Assessment of Cyanobacterial (Blue-green Algal) Toxins in Drinking Water. *International Journal of Research and Public Health* 2(1): 43–50.

[37] Carmichael, W.W. 2000. *Assessment of Blue-Green Algal Toxins in Raw and Finished Drinking Water.* AWWA Research Foundation, Denver, CO.

[38] For more information, refer to Manassaram, Deana M., Lorraine C. Backer, and Deborah M. Moll. 2006. *A Review of Nitrates in Drinking Water: Maternal Exposure and Adverse Reproductive and Developmental Outcomes.* Environmental Health Perspect. 114(3): 320–327.

[39] USEPA. 2007. *Nitrates and Nitrites: TEACH Chemical Summary.* U.S. Environmental Protection Agency. *http://www.epa.gov/teach/chem_summ/Nitrates_summary.pdf.* Accessed December 2009.

[40] Dubrovsky, N.M., Burow, K.R., Clark, G.M., Gronberg, J.M., Hamilton P.A., Hitt, K.J., Mueller, D.K., Munn, M.D., Nolan, B.T., Puckett, L.J., Rupert, M.G., Short, T.M., Spahr, N.E., Sprague, L.A., and Wilber, W.G. 2010. *The quality of our Nation's waters—Nutrients in the Nation's streams and groundwater, 1992–2004:* U.S. Geological Survey Circular 1350, 174p. Available electronically at: *http://water.usgs.gov/nawqa/nutrients/pubs/circ1350.*

[41] The serious illness in infants is caused because nitrate is converted to nitrite in the body. Nitrite interferes with the oxygen carrying capacity of the child's blood. This is an acute disease in that symptoms can develop rapidly in infants. In most cases, health deteriorates over a period of days. Symptoms include shortness of breath and blueness of the skin. (source: FDEP. 2010. Drinking Water: Inorganic Contaminants. Florida Department of Environmental Protection. *http://www.dep.state.fl.us/water/drinkingwater/inorg_con.htm.* Accessed September 2010.)

against the risk of these adverse effects[42] * * * Drinking water that meets the EPA standard is associated with little to none of this risk and is considered safe with respect to nitrate."[43]

Human health can also be impacted by disinfection byproducts formed when disinfectants (such as chlorine) used to treat drinking water react with organic carbon (from the algae in source waters). Some disinfection byproducts have been linked to rectal, bladder, and colon cancers; reproductive health risks; and liver, kidney, and central nervous system problems.[44] [45]

Economic losses from algal blooms and harmful algal blooms can include increased costs for drinking water treatment, reduced property values for streams and lakefront areas, commercial fishery losses, and lost revenue from recreational fishing, boating trips, and other tourism-related businesses.

In terms of increased costs for drinking water treatment, for example, in 1991, Des Moines (Iowa) Water Works constructed a $4 million ion exchange facility to remove nitrate from its drinking water supply. This facility was designed to be used an average of 35–40 days per year to remove excess nitrate levels at a cost of nearly $3000 per day.[46]

Fremont, Ohio (a city of approximately 20,000) has experienced high levels of nitrate from its source, the Sandusky River, resulting in numerous drinking water use advisories. An estimated $15 million will be needed to build a reservoir (and associated piping) that will allow for selective withdrawal from the river to avoid elevated levels of nitrate, as well as to provide storage.[47]

In regulating allowable levels of chlorophyll *a* in Oklahoma drinking water reservoirs, the Oklahoma Water Resources Board estimated that the long-term cost savings in drinking water treatment for 86 systems would range between $106 million and $615 million if such regulations were implemented.[48]

3. Nitrogen/Phosphorus Pollution in Florida

Florida's flat topography causes water to move slowly over the landscape, allowing ample opportunity for nitrogen and phosphorus to dissolve and eutrophication responses to develop. Florida's warm and wet, yet sunny, climate further contributes to increased run-off and ideal temperatures for subsequent eutrophication responses.[49]

As outlined in the EPA January 2009 determination and the January 2010 proposal, water quality degradation resulting from excess nitrogen and phosphorus loadings is a documented and significant environmental issue in Florida. FDEP notes in its *2008 Integrated Water Quality Assessment* that nutrient pollution poses several challenges in Florida. For example, the FDEP *2008 Integrated Water Quality Assessment* notes: "the close connection between surface and ground water, in combination with the pressures of continued population growth, accompanying development, and extensive agricultural operations, present Florida with a unique set of challenges for managing both water quality and quantity in the future. After trending downward for 20 years, beginning in 2000 phosphorus levels again began moving upward, likely due to the cumulative impacts of nonpoint source pollution associated with increased population and development. Increasing pollution from urban stormwater and agricultural activities is having other significant effects. In many springs across the State, for example, nitrate levels have increased dramatically (twofold to threefold) over the past 20 years, reflecting the close link between surface and ground water."[50] To clarify current nitrogen/phosphorus pollution conditions in Florida, EPA analyzed recent STORET data pulled from Florida's Impaired Waters Rule (IWR),[51] (which are the data Florida uses to create its integrated reports) and found increasing levels of nitrogen and phosphorus compounds in Florida waters over the past 12 years (1996–2008). Florida's IWR STORET data indicates that levels of total nitrogen have increased from a Statewide average of 1.06 mg/L in 1996 to 1.27 mg/L in 2008 and total phosphorus levels have increased from an average of 0.108 mg/L in 1996 to 0.151 mg/L in 2008.

The combination of the factors reported by FDEP and listed above (including population increase, climate, stormwater runoff, agriculture, and topography) has contributed to significant nitrogen/phosphorus effects to Florida's waters.[52] For example, newspapers in Florida regularly report about impacts associated with nitrogen/phosphorus pollution; recent examples include reports of algal blooms and fish kills in the St Johns River[53] and reports of white foam associated with algal blooms lining parts of the St. Johns River.[54] Spring releases of water from Lake Okeechobee into the St Lucie Canal, necessitated by high lake levels due to rainfall, resulted in reports of floating mats of toxic *Microcystis aeruginosa* that prompted Martin and St Lucie county health departments to issue warnings to the public.[55]

The *2008 Integrated Water Quality Assessment* lists nutrients as the fourth major source of impairment for rivers and streams in Florida (after dissolved oxygen, mercury in fish, and fecal coliforms). For lakes and estuaries, nutrients are ranked first and second, respectively. These same rankings are also confirmed in FDEP's latest *2010 Integrated Water Quality Assessment.*

[42] EPA has also set a drinking water standard for nitrite at 1 mg/L. To allow for the fact that the toxicity of nitrate and nitrite are additive, EPA has also established a standard for the sum of nitrate and nitrite at 10 mg/L. (source: FDEP. 2010. Drinking Water: Inorganic Contaminants. Florida Department of Environmental Protection. *http://www.dep.state.fl.us/water/drinkingwater/inorg_con.htm.* Accessed September 2010.)

[43] FDEP. 2010. Drinking Water: Inorganic Contaminants. Florida Department of Environmental Protection. *http://www.dep.state.fl.us/water/drinkingwater/inorg_con.htm.* Accessed September 2010.

[44] USEPA. 2009. *National Primary Drinking Water Regulations.* Contaminants. U.S. Environmental Protection Agency. Accessed *http://www.epa.gov/safewater/hfacts.html.* December 2009.

[45] National Primary Drinking Water Regulations: Stage 2 Disinfectants and Disinfection Byproducts Rule, 40 CFR parts 9, 141, and 142. U.S. Environmental Protection Agency, FR 71:2 (January 4, 2006). pp. 387–493. Available electronically at: *http://www.epa.gov/fedrgstr/EPA-WATER/2006/January/Day-04/w03.htm.* Accessed December 2009.

[46] Jones, C.S., D. Hill, and G. Brand. 2007. Use a multifaceted approach to manage high sourcewater nitrate. *Opflow* June pp. 20–22.

[47] Taft, Jim, Association of State Drinking Water Administrators (ASDWA). 2009. Personal Communication.

[48] Moershel, Philip, Oklahoma Water Resources Board (OWRB) and Mark Derischweiler, Oklahoma Department of Environmental Quality (ODEQ). 2009. Personal Communication.

[49] Perry, W. B. 2008. Everglades restoration and water quality challenges in south Florida. *Ecotoxicology* 17:569–578.

[50] FDEP. 2008. Integrated Water Quality Assessment for Florida: 2008 305(b) Report and 303(d) List Update.

[51] IWR Run 40. Updated through February 2010.

[52] FDEP. 2008. Integrated Water Quality Assessment for Florida: 2008 305(b) Report and 303(d) List Update.

[53] Patterson, S. 2010, July 23. *St John's River Looks Sick.* Florida Times Union. *http://jacksonville.com/news/metro/2010-07-23/story/st-johns-looks-sick-nelson-says.* Accessed September 2010.

[54] Patterson, S. 2010, July 21. *Foam on St. John's River Churns Up Environmental Interest.* Florida Times Union. *http://jacksonville.com/news/metro/2010-07-21/story/foam-st-johns-churns-environmental-questions.* Accessed October 2010.

[55] Killer, E. 2010, June 10. *Blue-green Algae Found Floating Near Palm City as Lake Okeechobee Releases Continue.* Treasure Coast Times. *http://www.tcpalm.com/news/2010/jun/10/blue-green-algae-found-floating-near-palm-city-o/.* Accessed October 2010.

According to FDEP's *2008 Integrated Water Quality Assessment*,[56] approximately 1,049 miles of rivers and streams, 349,248 acres of lakes, and 902 square miles of estuaries are impaired by nutrients in the State. To put this in context and as noted above, approximately 5% of the total assessed river and stream miles, 23% of the total assessed lake acres, and 24% of the total assessed square miles of estuaries are impaired for nutrients according to the 2008 Integrated Report.[57] In recent published listings of impairments for 2010, Florida Department of Environmental Protection lists nutrient impairments in 1,918 stream miles (about 8% of the total assessed stream miles), 378,435 lake acres (about 26% of total assessed lake acres), and 569 square miles of estuaries (about 21% of total assessed estuarine square miles).[58]

Compared to FDEP's *2008 Integrated Water Quality Assessment*, the *2010 Integrated Water Quality Assessment* shows an increase in nutrient impairments for rivers and streams (from approximately 1000 miles to 1918 miles) and lakes (from approximately 350,000 lake acres to 378,435 lake acres). While the square miles of estuaries identified as impaired by nutrients decreased from 2008 to 2010 (from approximately 900 to 569 square miles), the *2010 Integrated Water Quality Assessment* notes that all square miles of estuaries in the report were decreased based on improved GIS techniques and corrected waterbody descriptions.[59] Consequently, the decrease in estuarine square miles identified as impaired by nutrients in 2010 does not necessarily reflect a corresponding decrease in nitrogen/phosphorus pollution affecting Florida's estuarine water bodies.

FDEP has expressed concern about nitrogen/phosphorus pollution in Florida surface waters,[60] in addition to concerns about freshwater harmful algal blooms and the potential for adverse human health impacts as noted in FDEP's *2008 Integrated Water Quality Assessment*.[61] This concern is underscored by a toxic blue-green algae bloom that occurred north of the Franklin Lock on the Caloosahatchee River in mid-June 2008. The Olga Water Treatment Plant, which obtains its source water from the Caloosahatchee and provides drinking water for 30,000 people, was forced to temporarily shut down as a result of this bloom.[62]

There has also been an increase in the level of pollutants, especially nitrate, in groundwater over the past decades.[63] The Florida Geological Survey concluded that "The presence of nitrate and the other nitrogenous compounds in ground water, is not considered in Florida to be a result of interaction of aquifer system water with surrounding rock materials. Nitrate in ground water is a result of specific land uses."[64]

Historically, nitrate+nitrite concentrations in Florida's spring discharges were estimated to have been around 0.05 mg/L or less, which is sufficiently low to restrict growth of algae and vegetation under "natural" conditions.[65] Of 125 spring vents sampled by the Florida Geological Survey in 2001–2002, 42% had nitrate+nitrite concentrations exceeding 0.50 mg/L and 24% had concentrations greater than 1.0 mg/L.[66] In the same study, mean nitrate+nitrite levels in 13 first-order springs were observed to have increased from 0.05 mg/L to 0.9 mg/L between 1970 and 2002. Overall, data suggest that nitrate+nitrite concentrations in many spring discharges have increased by an order of magnitude or a factor of 10 over the past 50 years, with the level of increase closely correlated with anthropogenic activity and land use changes within the karst regions of Florida where springs most often occur.[67]

Nitrates are found in ground water and wells in Florida, ranging from the detection limit of 0.02 mg/L to over 20 mg/L. Monitoring of Florida Public Water Supplies from 2004–2009 indicates that exceedances of nitrate maximum contaminant levels (MCL) (which are measured at the entry point of the distribution system and represent treated drinking water from a supplier) reported by drinking water plants in Florida ranged from 34–40 annually, during this period.[68]

About 10% of Florida residents receive their drinking water from a private well or small public source not inventoried under public supply.[69] A study in the late 1980s conducted by Florida Department of Agriculture and Consumer Services (FDACS) and FDEP, analyzed 3,949 shallow drinking water wells for nitrate.[70] [71] Nitrate was detected in 2,483 (63%) wells, with 584 wells (15%) above the MCL of 10 mg/L. Of the 584 wells that exceeded the MCL, 519 were located in Lake, Polk,

[56] FDEP. 2008. Integrated Water Quality Assessment for Florida: 2008 305(b) Report and 303(d) List Update.

[57] FDEP. 2008. Integrated Water Quality Assessment for Florida: 2008 305(b) Report and 303(d) List Update.

[58] FDEP. 2010. Integrated Water Quality Assessment for Florida: 2010 305(b) Report and 303(d) List Update.

[59] FDEP. 2010. Integrated Water Quality Assessment for Florida: 2010 305(b) Report and 303(d) List Update.

[60] "While significant progress has been made in reducing nutrient loads from point sources and from new development, nutrient loading and the resulting harmful algal blooms continue to be an issue. The occurrence of blue-green algae is natural and has occurred throughout history; however, algal blooms caused by nutrient loading from fertilizer use, together with a growing population and the resulting increase in residential landscapes, are an ongoing concern." FDEP. 2010. Integrated Water Quality Assessment for Florida: 2010 305(b) Report and 303(d) List Update.

[61] "Freshwater harmful algal blooms (HABs) are increasing in frequency, duration, and magnitude and therefore may be a significant threat to surface drinking water resources and recreational areas. Abundant populations of blue-green algae, some of them potentially toxigenic, have been found statewide in numerous lakes and rivers. In addition, measured concentrations of cyanotoxins—a few of them of above the suggested guideline levels—have been reported in finished water from some drinking water facilities." FDEP. 2008. Integrated Water Quality Assessment for Florida: 2008 305(b) Report and 303(d) List Update.

[62] Peltier, M. 2008. *Group files suit to enforce EPA water standards*. Naples News. *http://news.caloosahatchee.org/docs/NaplesNews_080717.htm*. Accessed August 2010.

[63] Scott, T.M., G.H. Means, R.P. Meegan, R.C. Means, S.B. Upchurch, R.E. Copeland, J. Jones, T. Roberts, and A. Willet. 2004. *Springs of Florida*. Bulletin No. 66. Florida Geological Survey, Tallahassee, FL. 677 pp.

[64] FL Geological Survey. 1992. Special Publication No. 34, Florida's Ground Water Quality Monitoring Program, (nitrate-pp 36–6).

[65] Maddox, G.L., J.M. Lloyd, T.M. Scott, S.B. Upchurch and R. Copeland. 1992. *Florida's Groundwater Quality Monitoring Program—Background Hydrochemistry*. Florida Geological Survey Special Publication No. 34, Tallahassee, FL.

[66] Scott, T.M., G.H. Means, R.P. Meegan, R.C. Means, S.B. Upchurch, R.E. Copeland, J. Jones, T. Roberts, and A. Willet. 2004. *Springs of Florida*. Bulletin No. 66. Florida Geological Survey, Tallahassee, FL. 677 pp.

[67] Katz, B.G., H.D. Hornsby, J.F. Bohlke and M.F. Mokray. 1999. *Sources and chronology of nitrate contamination in spring water, Suwannee River Basin, Florida*. Water-Resources Investigations Report 99–4252. U.S. Geological Survey, Tallahassee, FL. Available electronically at: *http://fl.water.usgs.gov/PDF_files/wri99_4252_katz.pdf*.

Scott, T.M., G.H. Means, R.P. Meegan, R.C. Means, S.B. Upchurch, R.E. Copeland, J. Jones, T. Roberts, and A. Willet. 2004. *Springs of Florida*. Bulletin No. 66. Florida Geological Survey, Tallahassee, FL. 677 pp.

[68] FDEP. 2009. *Chemical Data for 2004, 2005, 2006, 2007 2008, and 2009*. Florida Department of Environmental Protection. *http://www.dep.state.fl.us/water/drinkingwater/chemdata.htm*. Accessed January 2010.

[69] Marella, R.L. 2009. *Water Withdrawals, Use, and Trends in Florida, 2005*. Scientific Investigations Report 2009–5125. U.S. Geological Survey, Reston, VA.

[70] Southern Regional Water Program. 2010. *Drinking Water and Human Health in Florida. http://srwqis.tamu.edu/florida/program-information/florida-target-themes/drinking-water-and-human-health.aspx*. Accessed January 2010.

[71] T.A. Obreza and K.T. Morgan. 2008. *Nutrition of Florida Citrus Trees* 15 months after publication of the final rule, except for the Federal site-specific alternative criteria (SSAC) procedure in section 131.43(e) of the rule which will go into effect 60 days after publication. 2nd ed. SL 253. University of Florida, IFAS Extension. *http://edis.ifas.ufl.edu/pdffiles/SS/SS47600.pdf*. Accessed September 2010.

and Highland counties located in Central Florida. Results of monitoring conducted between 1999 and 2003 in a network of wells in that area indicated that of the 31 monitoring wells, 90% exceeded the nitrate drinking-water standard of 10 mg/L one or more times.[72] [73] FDEP monitored this same area (the VISA monitoring network) in 1990, 1993, and 1996, analyzing samples from 15–17 wells each cycle and reported median concentrations ranging from 17 to 20 mg/L nitrate, depending on the year.[74] Some areas of Florida tend to be more susceptible to groundwater impacts from nitrogen pollution, especially those that have sandy soils, have high hydraulic conductivity, and have overlying land uses that are subject to applications of fertilizers and animal or human wastes.[75] For example, USGS reports that in Highland county, highly developed suburban and agricultural areas tend to have levels of nitrates in the surficial groundwater that approach and can exceed the State primary drinking water standard of 10 mg/L for public water systems. Other areas in Highland county that are less developed tend to have much lower levels of nitrates in the surficial groundwater, often below detection levels.

The Floridian aquifer system is one of the largest sources of ground water in the U.S., and serves as a primary source of drinking water in Northern Florida. The Upper Floridian aquifer is unconfined or semiconfined in areas in Northern Florida, but is also confined by the overlying surficial aquifer system which is used for water supply. Wells in unconfined areas of the Upper Floridian aquifer tested in northern Florida had nitrate levels higher than 1 mg/L in 40% of wells; 17% of samples from the semiconfined area had nitrate levels above 1 mg/L. In both aquifer systems this indicates the widespread impact of nitrate on groundwater quality in this area.[76] [77] This baseline sampling indicates a pattern of widespread nitrate occurrence in the Upper Floridian aquifer from two decades ago. A portion of these early samples exceeded 10 mg/L nitrate (25 of the 726 samples taken from this unconfined or semi-confined aquifer; 50 of the 421 water samples from the surficial aquifer).

Growing population trends in Florida contribute to the significant challenge of addressing nitrogen/phosphorus pollution in Florida. Historically, the State has experienced a rapidly expanding population. Significantly growing demographics are considered to be a strong predictor of nitrogen/phosphorus loading and associated effects because of increases in stormwater runoff from increased impervious surfaces and increased wastewater treatment flows both of which typically contain some level of nitrogen/phosphorus.[78] Florida is currently the fourth most populous State in the nation, with an estimated 18 million people.[79] The U.S. Census bureau predicts the Florida population will exceed 28 million people by 2030, making Florida the third most populous State in the U.S.[80]

B. Statutory and Regulatory Background

Section 303(c) of the CWA (33 U.S.C. 1313(c)) directs States to adopt WQS for their navigable waters. Section 303(c)(2)(A) and EPA's implementing regulations at 40 CFR part 131 require, among other things, that State WQS include the designated use or uses to be made of the waters and criteria that protect those uses. EPA regulations at 40 CFR 131.11(a)(1) provide that States shall "adopt those water quality criteria that protect the designated use" and that such criteria "must be based on sound scientific rationale and must contain sufficient parameters or constituents to protect the designated use." As noted above, 40 CFR 130.10(b) provides that "[i]n designating uses of a waterbody and the appropriate criteria for those uses, the State shall take into consideration the water quality standards of downstream waters and ensure that its water quality standards provide for the attainment and maintenance of the water quality standards of downstream waters."

States are also required to review their WQS at least once every three years and, if appropriate, revise or adopt new standards. (*See* CWA section 303(c)(1)). Any new or revised WQS must be submitted to EPA for review and approval or disapproval. (*See* CWA section 303(c)(2)(A)). Finally, CWA section 303(c)(4)(B) authorizes the Administrator to determine, even in the absence of a State submission, that a new or revised standard is needed to meet CWA requirements. The criteria finalized in this rulemaking translate Florida's narrative nutrient provision at Subsection 62–302–530(47)(b), F.A.C., into numeric values that apply to lakes and springs throughout Florida and flowing waters outside of the South Florida Region.[81]

C. Water Quality Criteria

Under CWA section 304(a), EPA periodically publishes criteria recommendations (guidance) for use by States in setting water quality criteria for particular parameters to protect recreational and aquatic life uses of waters. Where EPA has published recommended criteria, States have the option of adopting water quality criteria based on EPA's CWA section 304(a) criteria guidance, section 304(a) criteria guidance modified to reflect site-specific conditions, or other scientifically defensible methods. (*See* 40 CFR 131.11(b)(1)). For nitrogen/phosphorus pollution, EPA has published under CWA section 304(a) a series of peer-reviewed, national technical approaches and methods regarding the development of numeric criteria for lakes and reservoirs,[82] rivers and streams,[83] and estuaries and coastal marine waters.[84]

[72] T.A. Obreza and K.T. Morgan. 2008. *Nutrition of Florida Citrus Trees.* 2nd ed. SL 253. University of Florida, IFAS Extension. *http://edis.ifas.ufl.edu/pdffiles/SS/SS47800.pdf.* Accessed September 2010.

[73] USGS. 2009, November. *Overview of Agricultural Chemicals: Pesticides and Nitrate. http://fl.water.usgs.gov/Lake_Wales_Ridge/html/overview_of_agrichemicals.html.* Accessed September 2010.

[74] FDEP. 1998. *Ground Water Quality and Agricultural Land Use in the Polk County Very Intense Study Area (VISA).* Florida Department of Environmental Protection, Division of Water Facilities. *http://www.dep.state.fl.us/water/monitoring/docs/facts/fs9802.pdf.* Accessed September 2010.

[75] USGS. 2010. *Hydrogeology and Groundwater Quality of Highlands County, FL.* Scientific Investigations Report 2010–5097. U.S. Geological Survey, Reston, VA.

[76] Berndt, M.P., 1996. *Ground-water quality assessment of the Georgia-Florida Coastal Plain study unit—Analysis of available information on nutrients, 1972–92.* Water-Resources Investigations Report 95–4039. U.S. Geological Survey, Tallahassee, FL.

[77] Berndt, Marian P., 1993. *National Water-Quality Assessment Program-Preliminary assessment of nitrate distribution in ground water in the Georgia-Florida Coastal Plain Study Unit, 1972–90.* Open-File Report 93–478. U.S. Geological Survey.

[78] National Research Council, Committee on Reducing Stormwater Discharge Contributions to Water Pollution. 2008. *Urban Stormwater Management in the United States.* National Academies Press, Washington, DC.

[79] U.S. Census Bureau. 2009. 2008 Population Estimates Ranked by State. *http://factfinder.census.gov.* Accessed January 2010.

[80] U.S. Census Bureau. 2009. 2008 Population Estimates Ranked by State. *http://factfinder.census.gov.* Accessed January 2010.

[81] The criteria finalized in this rulemaking do not address or translate Florida's narrative nutrient provision at Subsection 62–302.530(47)(a), F.A.C. Subsection 62–302.530(47)(a), F.A.C., remains in place as an applicable WQS for CWA purposes.

[82] USEPA. 2000a. *Nutrient Criteria Technical Guidance Manual: Lakes and Reservoirs.* EPA–822–B–00–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[83] USEPA. 2000b. *Nutrient Criteria Technical Guidance Manual: Rivers and Streams.* EPA–822–B–00–002. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[84] USEPA. 2001. *Nutrient Criteria Technical Manual: Estuarine and Coastal Marine Waters.*

EPA based the methodologies used to develop numeric criteria for Florida in this regulation on its published guidance on developing criteria that identifies three general approaches for criteria setting. The three types of empirical analyses provide distinctly different, independently and scientifically defensible, approaches for deriving nutrient criteria from field data: (1) Reference condition approach derives candidate criteria from observations collected in reference waterbodies, (2) mechanistic modeling approach represents ecological systems using equations that represent ecological processes and parameters for these equations that can be calibrated empirically from site-specific data, and (3) empirical nutrient stressor-response modeling is used when data are available to accurately estimate a relationship between nutrient concentrations and a response measure that is directly or indirectly related to a designated use of the waterbody (*e.g.*, a biological index or recreational use measure). Then, nutrient concentrations that are protective of designated uses can be derived from the estimated relationship).[85] Each of these three analytical approaches is appropriate for deriving scientifically defensible numeric nutrient criteria when applied with consideration of method-specific data needs and available data. In addition to these empirical approaches, consideration of established (*e.g.*, published) nutrient response thresholds is also an acceptable approach for deriving criteria.[86]

For lakes, EPA used a stressor-response approach to link nitrogen/phosphorus concentrations to predictions of corresponding chlorophyll *a* concentrations. EPA used a reference-based approach for streams, relying on a comprehensive screening methodology to identify least-disturbed streams as reference streams. For springs, EPA used algal or nitrogen/phosphorus thresholds developed under laboratory conditions and stressor-response relationships from several field studies of algal growth in springs. For each type of waterbody, EPA carefully considered the available data and evaluated several lines of evidence to derive scientifically sound approaches (as noted above) for developing the final numeric criteria.

Based on comments received from the Scientific Advisory Board (SAB), EPA has modified a draft methodology guidance document on using stressor-response relationships for deriving numeric criteria, which is available as a final technical guidance document.[87] In addition, the reference-based and algal or nitrogen/phosphorus threshold approaches have been peer reviewed and have been available for many years.

As mentioned above, the criteria finalized in this rulemaking translate Florida's narrative nutrient provision at Subsection 62–302.530(47)(b), F.A.C., ("[i]n no case shall nutrient concentrations of a body of water be altered so as to cause an imbalance in natural populations of aquatic flora or fauna") into numeric values that apply to lakes and springs throughout the State and flowing waters outside of the South Florida Region. EPA believes that numeric criteria will expedite and facilitate the effective implementation of Florida's existing point and non-point source water quality programs in terms of timely water quality assessments, TMDL development, NPDES permit issuance and, where needed, Basin Management Action Plans (BMAPs) to address nitrogen/phosphorus pollution. EPA notes that Subsection 62–302.530(47)(a), F.A.C. ("[t]he discharge of nutrients shall continue to be limited as needed to prevent violations of other standards contained in this chapter. Man-induced nutrient enrichment (total nitrogen or total phosphorus) shall be considered degradation in relation to the provisions of Sections 62–302.300, 62–302.700, and 62–4.242, F.A.C.") could result in more stringent nitrogen/phosphorus limits, where necessary to protect other applicable WQS in Florida.

D. EPA Determination Regarding Florida and EPA's Rulemaking

On January 14, 2009, EPA determined under CWA section 303(c)(4)(B) that new or revised WQS in the form of numeric water quality criteria for nitrogen/phosphorus pollution are necessary to meet the requirements of the CWA in the State of Florida. As noted above, the portion of Florida's currently applicable narrative criterion translated by this final rule provides, in part, that "in no case shall nutrient concentrations of a body of water be altered so as to cause an imbalance in natural populations of aquatic flora or fauna." (*See* Subsection 62–302.530(47)(b), F.A.C.). EPA determined that Florida's narrative criterion alone was insufficient to ensure protection of applicable designated uses. The determination recognized that Florida has a comprehensive regulatory and non-regulatory administrative water quality program to address nitrogen/phosphorus pollution through a water quality strategy of assessments, non-attainment listing and determinations, TMDL development, and National Pollutant Discharge Elimination System (NPDES) permit regulations; individual watershed management plans through the State's BMAPs; advanced wastewater treatment technology-based requirements under the 1990 Grizzle-Figg Act; together with rules to limit nitrogen/phosphorus pollution in geographically specific areas like the Indian River Lagoon System, the Everglades Protection Area, and Wekiva Springs. However, the determination noted that despite Florida's existing regulatory and non-regulatory water quality framework and the State's intensive efforts to diagnose nitrogen/phosphorus pollution and address it on a time-consuming and resource-intensive case-by-case basis, substantial water quality degradation from nitrogen/phosphorus over-enrichment remains a significant challenge in the State and conditions are likely to worsen with continued population growth and land-use changes.

Overall, the combined impacts of urban and agricultural activities, along with Florida's physical features and important and unique aquatic ecosystems, made it clear that the current reliance on the narrative criterion alone and a resource-intensive, site-specific implementation approach, and the resulting delays that it entails, do not ensure protection of applicable designated uses for the many State waters that either have been listed as impaired and require loadings reductions or those that are high quality and require protection from future degradation. EPA concluded that numeric criteria for nitrogen/phosphorus pollution will enable the State to take necessary action to protect

EPA–822–B–01–003. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[85] USEPA. 2000a. *Nutrient Criteria Technical Guidance Manual: Lakes and Reservoirs.* EPA–822–B–00–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

USEPA. 2000b. *Nutrient Criteria Technical Guidance Manual: Rivers and Streams.* EPA–822–B–00–002. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

USEPA. 2001. *Nutrient Criteria Technical Guidance Manual: Estuarine and Coastal Marine Waters.* EPA–822–B–01–003. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

USEPA. 2008. *Nutrient Criteria Technical Guidance Manual: Wetlands.* EPA–822–B–08–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[86] USEPA. 2000a. *Nutrient Criteria Technical Guidance Manual: Lakes and Reservoirs.* EPA–822–B–00–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[87] USEPA. 2010. *Using Stressor-Response Relationships to Derive Numeric Nutrient Criteria.* EPA–820–S–10–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

the designated uses in a timely manner that will ensure protection of the designated use. The resource-intensive efforts to interpret the State's narrative criterion contribute to substantial delays in implementing the criterion and, therefore, undercut the State's ability to provide the needed protections for applicable designated uses. EPA, therefore, determined that numeric criteria for nitrogen/phosphorus pollution are necessary for the State of Florida to meet the CWA requirement to have criteria that protect applicable designated uses. EPA determined that numeric water quality criteria would strengthen the foundation for identifying impaired waters, establishing TMDLs, and deriving water quality-based effluent limits in NPDES permits, thus providing the necessary protection for the State's designated uses in its waters. In addition, numeric criteria will support the State's ability to effectively partner with point and nonpoint sources to control nitrogen/phosphorus pollution, thus further providing the necessary protection for the designated uses of the State's water bodies. EPA's determination is available at the following Web site: *http://www.epa.gov/waterscience/standards/rules/fl-determination.htm.*

While Florida continues to work to implement its watershed management program, the impairments for nutrient pollution are increasing as evidenced by the 2008 and 2010 *Integrated Water Quality Assessment for Florida* report results, and the tools to correct the impairments (TMDLs and BMAPs) are not being completed at a pace to keep up. Numeric criteria can be used as a definitive monitoring tool to identify impaired waters and as an endpoint for TMDLs to establish allowable loads necessary to correct impairments. When developing TMDLs, as it does when determining reasonable potential and deriving limits in the permitting context, Florida translates the narrative criterion into a numeric target that the State determines is necessary to meet its narrative criterion and protect applicable designated uses. This process involves a site-specific analysis to determine the nitrogen and phosphorus concentrations that would "cause an imbalance in natural populations of aquatic flora or fauna" in a particular water.

When deriving NPDES water quality-based permit limits, Florida initially conducts a site-specific analysis to determine whether a proposed discharge has the reasonable potential to cause or contribute to an exceedance of its narrative water quality criterion. The absence of numeric criteria make this "reasonable potential" analysis more complex, data-intensive, and protracted. Following a reasonable potential analysis, the State then evaluates what levels of nitrogen and phosphorus would "cause an imbalance in natural populations of aquatic flora or fauna" and translates those levels into numeric "targets" for the receiving water and any other affected waters. Determining on a State-wide, water-by-water basis the levels of nitrogen and phosphorus that would "cause an imbalance in natural populations of aquatic flora or fauna" is a difficult, lengthy, and data-intensive undertaking. This work involves performing detailed location-specific analyses of the receiving water. If the State has not already completed this analysis for a particular waterbody, it can be very difficult to accurately determine in the context and timeframe of the NPDES permitting process. For example, in some cases, site-specific data may take several years to collect and, therefore, may not be available for a particular waterbody at the time of permitting issuance or re-issuance.

The January 14, 2009 determination stated EPA's intent to propose numeric criteria for lakes and flowing waters in Florida within 12 months of the January 14, 2009 determination, and for estuarine and coastal waters within 24 months of the determination. On August 19, 2009, EPA entered into a Consent Decree with Florida Wildlife Federation, Sierra Club, Conservancy of Southwest Florida, Environmental Confederation of Southwest Florida, and St. Johns Riverkeeper, committing to the schedule stated in EPA's January 14, 2009 determination to propose numeric criteria for lakes and flowing waters in Florida by January 14, 2010, and for Florida's estuarine and coastal waters by January 14, 2011. The Consent Decree also required that final rules be issued by October 15, 2010 for lakes and flowing waters, and by October 15, 2011 for estuarine and coastal waters. FDEP, independently from EPA, initiated its own State rulemaking process in the spring/summer of 2009 to adopt nutrient water quality standards protective of Florida's lakes and flowing waters. FDEP held several public workshops on its draft numeric criteria for lakes and flowing waters. In October 2009, however, FDEP decided not to bring the draft criteria before the Florida Environmental Regulation Commission, as had been previously scheduled.

Pursuant to the Consent Decree, EPA's Administrator signed the proposed numeric criteria for Florida's lakes and flowing waters on January 14, 2010, which was published in the **Federal Register** on January 26, 2010. EPA conducted a 90-day public comment period for this rule that closed on April 28, 2010. During this period, EPA also conducted 13 public hearing sessions in 6 cities in Florida. EPA received over 22,000 public comments from a variety of sources, including environmental groups, municipal wastewater associations, industry, State agencies, local governments, agricultural groups, and private citizens. The comments addressed a wide range of issues, including technical analyses, policy issues, economic costs, and implementation concerns. In this notice, EPA explains the inland waters final rule and provides a summary of major comments and the Agency's response in the sections that describe each of the provisions of the final rule. EPA has prepared a detailed "Comment Response Document," which includes responses to the comments contributed during the public hearing sessions, as well as those submitted in writing on the proposed rule, and is located in the docket for this rule.

On June 7, 2010, EPA and Plaintiffs filed a joint notice with the Court extending the deadlines for promulgating numeric criteria for Florida's estuaries and coastal waters, flowing waters in south Florida (including canals), and the downstream protection values for flowing waters into estuaries and coastal waters. The new deadlines are November 14, 2011 for proposing this second phase of criteria, and August 15, 2012 for publishing a final rule for these three categories. This will allow EPA time to hold a public peer review by EPA's Scientific Advisory Board (SAB) of the scientific methodologies for estuarine and coastal criteria, flowing waters in south Florida, and downstream protection values for estuaries and coastal waters.

Based upon comments and new data and information received during the public comment phase of the January 2010 proposed rule, on August 3, 2010 EPA published a supplemental notice of data availability and request for comment related to the Agency's January 26, 2010 notice of proposed rulemaking. In its supplemental notice, EPA solicited comment on a revised regionalization approach for streams, additional information and analysis on least-disturbed sites as part of a modified benchmark distribution approach, and additional options for developing downstream protection values (DPVs) for lakes. EPA did not solicit additional comment on any other provisions of the January 2010 proposal. EPA received 71 public comments from a variety of sources, including local and State governments, industry, and

environmental groups. As mentioned above, EPA provides a summary of major comments and the Agency's response in the sections that describe each of the provisions of the final rule. Responses to comments submitted during the public comment period associated with the supplemental notice are also included in EPA's detailed "Comment Response Document," located in the docket for this rule.

On October 8, 2010, EPA filed an unopposed motion with the Court requesting that the deadline for signing the final rule be extended to November 14, 2010. The Court granted EPA's motion on October 27, 2010. EPA used this additional time to review and confirm that all comments were fully considered.

In accordance with the January 14, 2009 determination, the August 19, 2009 Consent Decree, and the June 7, 2010 and October 27, 2010 revisions to that Consent Decree, in this final notice EPA is promulgating final numeric criteria for streams, lakes, and springs in the State of Florida.[88]

III. Numeric Criteria for Streams, Lakes, and Springs in the State of Florida

A. General Information

For this final rule, EPA derived numeric criteria for streams, lakes and springs to implement Florida Subsection 62–302.530(47)(b), F.A.C.[89] This final rule also includes downstream protection values (DPVs) to ensure the attainment and maintenance of the WQS for downstream lakes. Derivation of these criteria is based upon an extensive amount of Florida-specific data. EPA has carefully considered numerous comments from a range of stakeholders and has worked in close collaboration with FDEP technical and scientific experts to analyze, evaluate, and interpret these Florida-specific data in deriving scientifically sound numeric criteria for this final rulemaking.

To support derivation of the final streams criteria, EPA screened and evaluated water chemistry data from more than 11,000 samples from over 6,000 sites statewide. EPA also evaluated biological data consisting of more than 2,000 samples from over 1,100 streams. To support derivation of the final lakes criteria, EPA screened and evaluated relevant lake data, which consisted of over 17,000 samples from more than 1,500 lakes statewide. Finally, for the final springs criterion, EPA evaluated and relied on scientific information and analyses from more than 40 studies including historical accounts, laboratory scale dosing studies and field surveys.

In deriving these final numeric values, the EPA met and consulted with FDEP expert scientific and technical staff on numerous occasions as part of an ongoing collaborative process. EPA carefully considered and evaluated the technical approaches and scientific analysis that FDEP presented as part of its July 2009 draft numeric criteria,[90] as well as its numerous comments on different aspects of this rule. The Agency also received and carefully considered substantial stakeholder input from 13 public hearings in 6 Florida cities. Finally, EPA reviewed and evaluated further analysis and information included in more than 22,000 comments on the January 2010 proposal and an additional 71 comments on the August 2010 supplemental notice.

EPA has created a technical support document that provides detailed information regarding the methodologies discussed herein and the derivation of the final criteria. This document is entitled "Technical Support Document for EPA's Final Rule for Numeric Criteria for Nitrogen/Phosphorus Pollution in Florida's Inland Surface Fresh Waters" ("EPA Final Rule TSD for Florida's Inland Waters" or "TSD") and is part of the record and supporting documentation for this final rule. As part of its review of additional technical and scientific information, EPA has documented its consideration of key comments and issues received from a wide range of interested parties during the rulemaking process. This analysis and consideration is included as part of a comment response document entitled "Response to Comments—EPA's Numeric Criteria for Nitrogen/Phosphorus Pollution in the State of Florida's Lakes and Flowing Waters" that is also part of the record and supporting documentation for this final rule.

This section of the preamble describes EPA's final numeric criteria for Florida's streams (III.B), lakes (III.C), and springs (III.D), with the associated methodologies EPA employed to derive them. Each subsection includes the final numeric criteria (magnitude, duration, and frequency) and background information and supporting analyses. Section III.E discusses the applicability and implementation of these final criteria.

As discussed, the scientific basis for the derivation of the applicable criteria for streams, lakes and springs in this final rule is outlined below and explained in more detail in the Technical Support Document accompanying this rulemaking. The final criteria and related provisions in this rule reflect a detailed consideration and full utilization of the best available science, data, literature, and analysis related to the specific circumstances and contexts for deriving numeric criteria in the State of Florida. This includes, but is not limited to, the substantial quantity and quality of available data in Florida, Florida's regional hydrologic, biological, and land use characteristics, and the biological responses in Florida's surface water systems.

B. Numeric Criteria for the State of Florida's Streams

(1) Final Rule

EPA is promulgating numeric criteria for TN and TP in five geographically distinct watershed regions of Florida's streams classified as Class I or III waters under Florida law (Section 62–302.400, F.A.C.).

TABLE B–1—EPA'S NUMERIC CRITERIA FOR FLORIDA STREAMS

Nutrient watershed region	Instream protection value criteria	
	TN (mg/L) *	TP (mg/L) *
Panhandle West[a]	0.67	0.06
Panhandle East[b]	1.03	0.18
North Central[c]	1.87	0.30
West Central[d]	1.65	0.49
Peninsula[e]	1.54	0.12

Watersheds pertaining to each Nutrient Watershed Region (NWR) were based principally on the NOAA coastal, estuarine, and fluvial drainage areas with modifications to the NOAA drainage areas in the West Central and Peninsula Regions that account for unique watershed geologies. For more detailed information on regionalization and which WBIDs pertain to each NWR, *see* the Technical Support Document.

[88] For purposes of this rule, EPA has distinguished South Florida as those areas south of Lake Okeechobee and the Caloosahatchee River watershed to the west of Lake Okeechobee and the St. Lucie watershed to the east of Lake Okeechobee, hereinafter referred to as the South Florida Region. Numeric criteria applicable to flowing waters in the South Florida Region will be addressed in the second phase of EPA's rulemaking regarding the establishment of estuarine and coastal numeric criteria. (Please refer to Section I.B for a discussion of the water bodies affected by this rule).

[89] In no case shall nutrient concentrations of a body of water be altered so as to cause an imbalance in natural populations of aquatic flora or fauna.

[90] FDEP. 2009. *Draft Technical Support Document: Development of Numeric Nutrient Criteria for Florida's Lakes and Streams.* Florida Department of Environmental Protection, Standards and Assessment Section. Available electronically at: *http://www.dep.state.fl.us/water/wqssp/nutrients/docs/tsd_nutrient_crit.docx.* Accessed October 2010.

[a] Panhandle West region includes: Perdido Bay Watershed, Pensacola Bay Watershed, Choctawhatchee Bay Watershed, St. Andrew Bay Watershed, Apalachicola Bay Watershed.

[b] Panhandle East region includes: Apalachee Bay Watershed, and Econfina/Steinhatchee Coastal Drainage Area.

[c] North Central region includes the Suwannee River Watershed.

[d] West Central region includes: Peace, Myakka, Hillsborough, Alafia, Manatee, Little Manatee River Watersheds, and small, direct Tampa Bay tributary watersheds south of the Hillsborough River Watershed.

[e] Peninsula region includes: Waccasassa Coastal Drainage Area, Withlacoochee Coastal Drainage Area, Crystal/Pithlachascotee Coastal Drainage Area, small, direct Tampa Bay tributary watersheds west of the Hillsborough River Watershed, Sarasota Bay Watershed, small, direct Charlotte Harbor tributary watersheds south of the Peace River Watershed, Caloosahatchee River Watershed, Estero Bay Watershed, Kissimmee River/Lake Okeechobee Drainage Area, Loxahatchee/St. Lucie Watershed, Indian River Watershed, Daytona/St. Augustine Coastal Drainage Area, St. John's River Watershed, Nassau Coastal Drainage Area, and St. Mary's River Watershed.

* For a given waterbody, the annual geometric mean of TN or TP concentrations shall not exceed the applicable criterion concentration more than once in a three-year period.

(2) Background and Analysis

(a) Methodology for Stream Classification

In January 2010, EPA proposed to classify Florida's streams into four regions (referred to in the proposed rule as "Nutrient Watershed Regions") for application of TN and TP criteria. This proposal was based upon the premise that streams within each of these regions (Panhandle, Bone Valley, Peninsula and North Central) reflect similar geographical characteristics, including phosphorus-rich soils, nitrogen/phosphorus concentrations and nitrogen to phosphorus ratios. To classify these four regions, EPA began by considering the watershed boundaries of downstream estuaries and coastal waters in recognition of the hydrology of Florida's flowing waters and the importance of protecting downstream water quality. This is consistent with a watershed approach to water quality management, which EPA encourages to integrate and coordinate efforts within a watershed in order to most effectively and efficiently protect our nation's water resources.[91] EPA then classified Florida's streams based upon a consideration of the natural factors that contribute to variability in nutrient concentrations in streams (*e.g.*, geology, soil composition). In the State of Florida, these natural factors are mainly associated with phosphorus. EPA's proposal reflected a conclusion that these natural factors could best be represented by separating the watersheds in the State into four regions and then using the least-disturbed sites within those regions to differentiate between the expected natural concentrations of TN and TP.

EPA received comments suggesting that the proposed stream regionalization be amended to more accurately account for naturally-high phosphorus soils in the northern Panhandle, west of the proposed North Central region. Specifically, EPA was asked to consider the westward extent of the Hawthorn Group, a phosphorus-rich geological formation that can influence stream phosphorus concentrations. At proposal, EPA had taken the Hawthorn Group into account when it proposed two distinct stream regions to the east and south of the panhandle region: the North Central and the West Central (formerly called the Bone Valley at proposal). Following proposal and in response to these comments, EPA revisited its review of underlying soils and geology in the Panhandle, itself, and the relationship of those geological characteristics to observed patterns in phosphorus concentrations in streams. EPA further considered how well such a revised regionalization explained observed variability in TP concentrations relative to the proposed regionalization. EPA concluded that a revised regional classification subdividing the proposed Panhandle region into a western and eastern section accurately reflected phosphate contributions from the underlying geologic formations that are reflected in the expected instream phosphorus concentrations. As discussed in the August 2010 supplemental notice, EPA has used the revised Panhandle regions for TN criteria to assure consistency and clarity in applicability decisions and implementation. This approach addresses the concerns of commenters that regionalization is an important consideration in developing stream criteria. EPA provided a supplemental notice and solicitation of comment in August 2010 on this potential change to the Panhandle region. In this final rule, EPA has thus taken into account the portion of the Hawthorn Group that lies in the eastern portion of the Panhandle region and has delineated the Panhandle region along watershed boundaries into East and West portions divided by the eastern edge of the Apalachicola River watershed (or alternatively, the western edge of the Suwannee River watershed). For more information regarding the EPA's consideration of alternative approaches for classification, please *see* the TSD and response to comments.

EPA also received comment that the original West Central region (referred to as the Bone Valley in the proposed rule) was too broad and incorporated watersheds that were not influenced by underlying Hawthorn Group geology, especially small, direct coastal drainage watersheds along the western and southern boundaries. EPA reexamined the watershed delineations of the West Central and Peninsula regions based on information in these comments and concluded that the comments were technically correct. EPA also provided a supplemental notice and solicitation of comment on this potential change to the West Central and Peninsula regions. In this final rule, EPA has refined the boundary delineations accordingly. The result for the West Central region was a modified boundary that shifts small, direct Tampa Bay tributary watersheds west of the Hillsborough River Watershed; small, direct Charlotte Harbor tributary watersheds south of the Peace River Watershed; and the entire Sarasota Bay Watershed from the West Central (Bone Valley) to the Peninsula region. EPA believes these adjustments to the West Central and Peninsula stream region boundaries more accurately reflect the watershed boundaries and better reflect natural differences in underlying geological formations and expected stream chemistry.

In summary, EPA is finalizing numeric stream criteria for TN and TP for five separate Nutrient Watershed Regions (NWR): Panhandle West, Panhandle East, North Central, West Central and Peninsula (north of Lake Okeechobee, including the Caloosahatchee River Watershed to the west and the St. Lucie Watershed to the east). For a map of these regions, refer to "Technical Support Document for U.S. EPA's Final Rule for Numeric Criteria for Nitrogen/Phosphorus Pollution in Florida's Inland Surface Fresh Waters" (Chapter 1: Derivation of EPA's Numeric Criteria for Streams) included in the docket as part of the record for this final rule.

(b) Methodology for Calculating Instream Protective TN and TP Values

In the January 2010 proposal, EPA used a reference condition approach to derive numeric criteria that relied on the identification of biologically healthy sites that were unimpaired by nitrogen or phosphorus. EPA identified these sites from FDEP's streams data set, selecting sites where Stream Condition

[91] U.S. EPA. 2008. *Handbook for Developing Watershed Plans to Restore and Protect Our Waters.* EPA 841–B–08–002. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

Index (SCI) scores were 40 and higher. The SCI is a multi-metric index of benthic macroinvertebrate community composition and taxonomic data developed by FDEP to assess the biological health of Florida's streams.[92] An SCI score > 40 has been determined to be indicative of biologically healthy conditions based on an expert workshop and analyses performed by both FDEP and EPA. Please refer to the EPA's January 2010 proposal and the final TSD accompanying this final rule for more information on the SCI and the selection of the SCI value of 40 as an appropriate threshold to identify biologically healthy sites.

EPA further screened these sites by cross-referencing them with Florida's 2008 CWA section 303(d) list and excluded sites in waterbody identification numbers (WBIDs) with identified nutrient impairments or dissolved oxygen impairments. EPA grouped the remaining sites (hereinafter referred to as "SCI sites") according to the four proposed Nutrient Watershed Regions (Panhandle, North Central, West Central (referred to as Bone Valley at proposal), and Peninsula). For each NWR, EPA compiled data (TN and TP concentrations). EPA then calculated the average concentration at each site using all available samples. The resulting site average concentrations represent the distribution of nitrogen/phosphorus concentrations for each region. EPA found that while these sites were determined to be biologically healthy, the proposed SCI approach does not include information that can be directly related to an evaluation of least anthropogenically-impacted conditions (*e.g.*, a measure of land use surrounding a reference site), which can be used as a factor in identifying a minimally-impacted reference population for criteria development. For these reasons, EPA concluded the 75th percentile of the distribution of site average values was an appropriate threshold to use in the SCI approach for criteria derivation.

EPA requested comment on basing the TN and TP criteria for the Nutrient Watershed Regions on the SCI approach. The Agency also requested comment on an alternative approach that utilizes benchmark sites identified by FDEP. EPA received comments supporting the benchmark reference condition approach and the selection of the 90th percentile (generally) for deriving the TN and TP criteria. The criteria in this final rule are based on a further evaluation and more rigorous screening of the benchmark data set of reference sites using the population of least-disturbed benchmark sites developed by FDEP and further refined by EPA as discussed in the August 2010 supplemental notice. EPA concluded that the revised benchmark approach is an appropriate reference condition approach for deriving stream criteria because it utilizes a quantitative assessment of potential human disturbance through the use of surrounding land cover analysis of stream corridor and watershed land development indices that provide an added dimension to the benchmark approach not considered in EPA's proposed SCI site approach. EPA is finalizing stream criteria for most NWRs based on the benchmark approach with the addition of supplemental data screening steps to ensure that an evaluation of benchmark sites utilizes best available information representing reference conditions related to least-disturbed as well as and biologically healthy streams in the State. For this reason, EPA found the benchmark reference condition approach to be a compelling basis to support numeric criteria for Florida's streams more closely associated with least-disturbed sites. For the West Central region only, EPA is finalizing stream criteria based on SCI sites because the benchmark approach resulted in the identification of only one WBID as being least-disturbed. EPA found the SCI sites provide a more compelling basis to support numeric criteria in that region because more data are available at more sites that have been identified as biologically healthy, which provide a broader representation of nitrogen and phosphorus concentrations within this region.

For this final rule, EPA is using the large amount of high-quality scientific data available on TN and TP concentrations with corresponding information on land use and human disturbance for a wide variety of stream types as part of a reference condition approach to derive numeric criteria for Florida's streams. EPA used available data that are quantitative measures of land use, indicators of human disturbance, and site-specific evaluations of biological condition using a multi-metric biological index to identify a population of least-disturbed benchmark locations (benchmark sites). EPA used associated measurements of TN and TP concentrations from the benchmark sites and SCI sites (in the case of the West Central region) as the basis for deriving the final numeric criteria for streams.

The reference condition approach used in this final rule for streams consist of three steps: (1) Defining the reference population, (2) calculating a distribution of values, and (3) determining appropriate thresholds. For the first step as discussed above, EPA used the least-disturbed benchmark reference condition approach initially developed by FDEP to define the reference condition population, this approach starts with a query of FDEP's data in the STORET[93] (STOrage and RETrieval) and GWIS (Generalized Water Information System) databases and identified sites with data that met quality assurance standards.[94] Sites with data were then evaluated by FDEP to assess the level of human disturbance in the vicinity of the site using the Landscape Development Intensity Index (LDI)[95] to analyze a 100 meter distance of land on both sides of and 10 kilometers upstream of each stream site (*i.e.*, corridor LDI). Sites with stream corridor LDI scores less than or equal to two[96] were considered sites with relatively low potential human disturbance. The group of sites with LDI scores less than or equal to two were further reviewed and inspected by FDEP based on site visits and aerial photography to assess the degree of potential human impact. Based on this review, sites that FDEP determined had potential human impact were removed. Sites with mean nitrate concentrations greater than 0.35 mg/L, a concentration identified by several lines of evidence to result in the growth of excessive algae in laboratory studies and extensive field evaluations of spring and clear stream sites in Florida[97] were also removed. Following proposal and in response to additional comments and information, EPA further evaluated the benchmark sites and screened out additional sites with identified nutrient impairments or dissolved oxygen impairments according to Florida's 2008 CWA section 303(d) list. EPA also removed sites that have available watershed LDI scores greater than three as this reflects a higher level of human disturbance on

[92] The SCI method was developed and calibrated by FDEP. *See* Fore *et al.* 2007, *Development and Testing of Biomonitoring Tools for Macroinvertebrates in Florida Streams (Stream Condition Index and BioRecon).* Final prepared for the Florida Department of Environmental Protection, Tallahassee, FL.

[93] FL STORET can be found at: *http://www.dep.state.fl.us/WATER/STORET/INDEX.HTM.*

[94] Quality assurance review conducted by FDEP and detailed in EPA's accompanying Technical Support Document.

[95] Brown, M.T., and M.B. Vivas. 2005. Landscape Development Intensity Index. *Environmental Monitoring and Assessment* 101: 289–309.

[96] Brown, M.T., and M.B. Vivas. 2005. Landscape Development Intensity Index. *Environmental Monitoring and Assessment* 101: 289–309.

[97] *See* the springs criterion discussion below.

a watershed basis.[98] Finally, EPA removed benchmark sites that have available Stream Condition Index (SCI) scores less than 40. These additional screens provide greater confidence that the remaining sites are both least-disturbed and biologically healthy. The benchmark approach resulted in the identification of only one WBID as least-disturbed within the West Central region. For this reason, EPA is utilizing the SCI sites identified at proposal to define the reference population for the West Central region in this final rule. EPA grouped the remaining sites (hereinafter referred to as "reference sites") according to its Nutrient Watershed Regions (Panhandle West, Panhandle East, North Central, West Central, and Peninsula). For each NWR, EPA compiled data (TN and TP concentrations) from the reference sites.

The second step in deriving instream protection values was to calculate the distribution of nitrogen/phosphorus values of benchmark sites within each region. EPA calculated the geometric mean of the annual geometric mean of nitrogen/phosphorus concentrations for each WBID within which reference sites occurred. EPA provided notice and solicited comment on calculating streams criteria on the basis of WBIDs in the August 2010 supplemental notice. All samples from reference sites within those WBIDs were used to calculate the annual geometric mean. The geometric mean of this annual geometric mean for each WBID is utilized so that each WBID represents one average concentration in the distribution of concentrations for each NWR. Geometric means were used for all averages because concentrations were log-normally distributed.

The third step in deriving instream protection values was to determine appropriate thresholds from these distributions to support balanced natural populations of aquatic flora and fauna. The upper end of the distribution (the 90th percentile) is appropriate if there is confidence that the distribution reflects minimally-impacted reference conditions and can be shown to be supportive of designated uses (*i.e.*, balanced natural populations of aquatic flora and fauna).[99] EPA concluded that the benchmark data set and the resulting benchmark distributions of TN and TP were based on substantial evidence of least-disturbed reference conditions after the additional quality assurance screens applied by EPA. This analysis provides EPA with the confidence that the benchmark sites are least-disturbed sites and with the additional screens applied by the Agency provide a basis for the use of the 90th percentile of values from this population to establish the final rule criteria. It is appropriate to use the 90th percentile for the benchmark distribution because the least-disturbed sites identified in Florida that are used to derive the criteria more closely approximate minimally-impacted conditions.[100] For the West Central region, where reference sites are identified using the SCI approach, there is less confidence that these sites are least-disturbed and represent minimally-impacted conditions. As mentioned above, this is because this approach does not rely on a quantitative assessment of potential human disturbance through the use of surrounding land cover analysis of stream corridor and watershed land development indices. Therefore, EPA is finalizing the stream criteria in the West Central region using the 75th percentile values of the distribution from the SCI sites.[101]

EPA's approach in this final rule results in numeric criteria that are protective of a balanced natural population of aquatic flora and fauna in Florida's streams. EPA has determined, however, that these instream values may not always ensure the attainment and maintenance of WQS in downstream lakes and that more stringent criteria may be necessary to assure compliance with 40 CFR 131.10(b). Therefore, EPA is finalizing an approach in this rule for deriving TN and TP values for streams to ensure the attainment and maintenance of WQS in downstream lakes.[102] This approach is discussed in Section III.C(2)(f).

(c) Duration and Frequency

Aquatic life water quality criteria contain three components: Magnitude, duration, and frequency. For the numeric TN and TP criteria for streams, the derivation of the criterion-magnitude values is described above and these values are provided in the table in Section III.B(1). The duration component of these stream criteria is specified in *footnote a* of Table B–1 as an annual geometric mean. EPA is finalizing the proposed frequency component as a no-more-than-one-in-three-years excursion frequency for the annual geometric mean criteria for streams. These duration and frequency components of the criteria are consistent with the data set used to derive these criteria, which applied distributional statistics to measures of annual geometric mean values from multiple years of record. EPA has determined that this frequency of excursions will not result in unacceptable effects on aquatic life as it will allow the stream ecosystem enough time to recover from occasionally elevated levels of nitrogen/phosphorus in the stream.[103] [104] [105] These selected duration and frequency components recognize that hydrological variability (*e.g.*, high and low flows) will produce variability in nitrogen and phosphorus concentrations, and that individual measurements may at times be greater than the criteria magnitude concentrations without causing unacceptable effects to aquatic organisms and their uses. Furthermore, the frequency and duration components balance the representation of underlying data and analyses based on the central tendency of many years of data with the need to exercise some caution to ensure that streams have sufficient time to process individual years of elevated nitrogen and phosphorus levels and

[98] The threshold value for watershed LDI is higher than the threshold value for the corridor LDI because human disturbance in the watershed is known to more weakly influence in-stream nitrogen/phosphorus concentrations than human disturbance in the stream corridor (Peterjohn, W.T. and D. L. Correll. 1984. Nutrient dynamics in an agricultural watershed: Observations on the role of a riparian forest. *Ecology* 65: 1466–1475).

[99] USEPA. 2008. *Nutrient Criteria Technical Guidance Manual: Wetlands*. EPA–822–B–08–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[100] The 90th percentile is selected so that nitrogen/phosphorus concentrations that are above the criterion value have a low probability (< 10%) of being observed in sites that are similar to benchmark sites.

[101] USEPA. 2000b. *Nutrient Criteria Technical Guidance Manual: Rivers and Streams*. EPA–822–B–00–002. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

These percentages were initially proposed by FDEP. *See* FDEP. 2009. *Draft Technical Support Document: Development of Numeric Nutrient Criteria for Florida's Lakes and Streams*. Florida Department of Environmental Protection, Standards and Assessment Section. Available electronically at: *http://www.dep.state.fl.us/water/wqssp/nutrients/docs/tsd_nutrient_crit.docx*. Accessed October 2010.

[102] EPA will propose and request comment on the comparable issue for deriving TN and TP values for streams to ensure the attainment and maintenance of WQS in downstream estuaries as part of the coastal and estuarine waters rule on November 14, 2011.

[103] USEPA. 1985. *Guidelines for Deriving Numeric National Water Quality Criteria for the Protection of Aquatic Organisms and Their Uses*. EPA PB85–227049. U.S. Environmental Protection Agency, Office of Research and Development, Environmental Research Laboratories.

[104] Hutchens, J. J., K. Chung, and J. B. Wallace. 1998. Temporal variability of stream macroinvertebrate abundance and biomass following pesticide disturbance. *Journal of the North American Benthological Society* 17:518–534.

[105] Wallace, J.B. D. S.Vogel, and T.F. Cuffney. 1986. Recovery of a headwater stream from an insecticide induced community disturbance. Journal of North American Benthological Society 5: 115–l 26.

avoid the possibility of cumulative and chronic effects (*i.e.*, the no-more-than-one-in-three-year component). More information on this specific topic is provided in EPA's Final Rule TSD for Florida's Inland Waters, Chapter 1: Methodology for Deriving U.S. EPA's Criteria for Streams located in the record for this final rule.

d. Reference Condition Approach

In deriving the final criteria for streams, EPA has relied on a reference condition approach, which has been well documented, peer reviewed, and developed in a number of different contexts.[106] [107] [108] [109] [110] In the case of Florida, this approach is supported by a substantial Florida-specific database of high quality information, sound scientific analysis and extensive technical evaluation.

EPA received comments regarding the scientific defensibility of the reference condition approach, using either the benchmark sites or the SCI sites. Many commenters observed that such approaches do not mechanistically link biological effects to nitrogen/phosphorus levels and therefore assert that EPA cannot scientifically justify numeric criteria without an observed biological effect. EPA views the reference condition approach as scientifically appropriate to derive the necessary numeric criteria in Florida streams. Reference conditions provide the appropriate benchmark against which to determine the nitrogen and phosphorus concentrations present when the designated use is being met. When the natural background concentrations of specific parameters can be defined by identifying reference conditions at anthropogenically-undisturbed sites, then the concentrations at these sites can be considered as sufficient to support the aquatic life expected to occur naturally at that site.[111] Also, setting criteria based on the conditions observed in reference condition sites reflects both the stated goal of the Clean Water Act and EPA's National Nutrient Strategy that calls for States, including Florida, to take protective and preventative steps in managing nitrogen/phosphorus pollution to maintain the chemical, physical and biological integrity of the Nation's waters before adverse biological and/or ecological effects are observed.[112]

The effects of TN and TP on an aquatic ecosystem are well understood and documented. There is a substantial and compelling scientific basis for the conclusion that excess TN and TP will have adverse effects on streams[113] [114] [115] [116] [117] [118] [119] [120] [121] [122] [123] [124] [125] [126] [127].

As discussed in Section II above, excess nitrogen/phosphorus in streams, like other aquatic ecosystems, increase vegetative growth (plants and algae), and change the assemblage of plant and algal species present in the system. These changes can affect the organisms that are consumers of algae and plants by altering the balance of food resources available to different trophic levels. For example, excess nitrogen/phosphorus promotes the growth of opportunistic and short-lived plant species that die quickly leaving more dead vegetative material available for consumption by lower tropic levels. Additionally, excess nitrogen/phosphorus can promote the growth of less palatable nuisance algae species that results in less food available for filter feeders. These changes can also alter the habitat structure by covering the stream or river bed with periphyton (attached algae) rather than submerged aquatic plants, or clogging the water column with phytoplankton (floating algae). In addition, excess nitrogen/phosphorus can lead to the production of algal toxins that can be toxic to fish, invertebrates, and humans. Chemical characteristics of the water, such as pH and concentrations of dissolved oxygen (DO), can also be affected by excess nitrogen/phosphorus leading to low DO conditions and hypoxia. Each of these changes can, in turn, lead to other changes in the stream community and, ultimately, to changes in the stream ecology that supports the overall function of the linked aquatic ecosystem.

[106] USEPA. 2000a. *Nutrient Criteria Technical Guidance Manual: Lakes and Reservoirs.* EPA–822–B–00–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[107] USEPA. 2000b. *Nutrient Criteria Technical Guidance Manual: Rivers and Streams.* EPA–822–B–00–002. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

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[110] U.S. EPA. 2001. Nutrient Criteria Technical Manual: Estuarine and Coastal Marine Waters. Office of Water, Washington, DC. EPA–822–B–01–003.

[111] Davies, T.T., USEPA. 1997, November 5. Memorandum to Water Management Division Directors, Regions 1–10, and State and Tribal Water Quality Management Program Directors on Establishing Site Specific Aquatic Life Criteria Equal to Natural Background.

[112] USEPA. 1998. *National Strategy for the Development of Regional Nutrient Criteria.* EPA 822–R–98–002. U.S. Environmental Protection Agency, Office of Water, Washington, DC; Grubbs, G., USEPA. 2001, November 14. Memorandum to Directors of State Water Programs, Directors of Great Water Body Programs, Directors of Authorized Tribal Water Quality Standards Programs and State and Interstate Water Pollution Control Administrators on Development and Adoption of Nutrient Criteria into Water Quality Standards.; Grumbles, B.H., USEPA. 2007, May 25.Memorandum to Directors of State Water Programs, Directors of Great Water Body Programs, Directors of Authorized Tribal Water Quality Standards Programs and State and Interstate Water Pollution Control Administrators on Nutrient Pollution and Numeric Water Quality Standards.

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C. Numeric Criteria for the State of Florida's Lakes

(1) Final Rule

EPA is promulgating numeric criteria for chlorophyll *a*, TN and TP in three classes of Florida's lakes, classified as Class I or III waters under Florida law (Section 62–302.400, F.A.C.):

TABLE C–17—EPA'S NUMERIC CRITERIA FOR FLORIDA LAKES

Lake color[a] and alkalinity	Chl-a (mg/L)[b]*	TN (mg/L)	TP (mg/L)
Colored Lakes[c]	0.020	1.27 [1.27–2.23]	0.05 [0.05–0.16]
Clear Lakes, High Alkalinity[d]	0.020	1.05 [1.05–1.91]	0.03 [0.03–0.09]
Clear Lakes, Low Alkalinity[e]	0.006	0.51 [0.51–0.93]	0.01 [0.01–0.03]

[a] Platinum Cobalt Units (PCU) assessed as true color free from turbidity.
[b] Chlorophyll *a* is defined as corrected chlorophyll, or the concentration of chlorophyll *a* remaining after the chlorophyll degradation product, phaeophytin *a*, has been subtracted from the uncorrected chlorophyll *a* measurement.
[c] Long-term Color > 40 Platinum Cobalt Units (PCU).
[d] Long-term Color ≤ 40 PCU and Alkalinity > 20 mg/L $CaCO_3$.
[e] Long-term Color ≤ 40 PCU and Alkalinity ≤ 20 mg/L $CaCO_3$.
* For a given waterbody, the annual geometric mean of chlorophyll *a*, TN or TP concentrations shall not exceed the applicable criterion concentration more than once in a three-year period.

For each class of water defined by color and alkalinity, the applicable criteria are the values in **bold** for chlorophyll *a*, TN and TP. The criteria framework provides flexibility for FDEP to derive lake-specific, modified TN and TP criteria if the annual geometric mean chlorophyll *a* concentration is less than the criterion for an individual lake in each of the three immediately preceding years. In such a case, the corresponding criteria for TN and/or TP may be modified to reflect maintenance of ambient conditions within the range specified in the parenthetical below each baseline TN and TP criteria printed in bold in Table C–1 above. Modified criteria for TN and/or TP must be based on data from at least the immediately preceding three years [128] in a particular lake. Modified TN and/or TP criteria may not be greater than the higher value specified in the range. Modified TN and/or TP criteria for a lake also may not be above criteria applicable to streams to which a lake discharges in order to ensure the attainment and maintenance of downstream water quality standards.

Utilization of the range flexibility in the numeric lake criteria in this final rule requires that the ambient calculation for modified TN and TP criteria be based on: (1) The immediately preceding three-year record of observation for each parameter,[129] (2) representative sampling during each year (at least one sample in May–September and at least one sample in October–April), and (3) a minimum of 4 samples from each year. Requiring at least three years of data accounts for year-to-year hydrological variability, ensures longer-term stable conditions, and appropriately accounts for anomalous conditions in any given year that could lead to erroneous conclusions regarding the true relationship between nitrogen/phosphorus and chlorophyll *a* levels in a lake. Representative samples from each year minimize the effects of seasonal variations in nitrogen/phosphorus and chlorophyll *a* concentrations. Finally, the minimum sample size of 4 samples per year allows estimates of reliable geometric means while still maintaining a representative sample of lakes. The State shall notify EPA Region 4 and provide the supporting record within 30 days of determination of modified lake criteria.

To ensure attainment of applicable downstream lake criteria, this final rule provides a tiered approach for adjusting instream criteria presented in section III.B.(1) above for those streams that flow into lakes.[130] Where site-specific data on lake characteristics are available, the final rule provides a modeling approach for the calculation of downstream lake protection values that relies upon the use of the BATHTUB model.[131] In circumstances where sufficient site-specific lake data are readily available and either EPA or FDEP determine that another scientifically defensible model is more appropriate (*e.g.*, the Water Quality Analysis Simulation Program, or WASP), the modeling approach accommodates use of a scientifically defensible alternative. In the absence of models, other approaches for ensuring protection of downstream lakes are provided and described further below.

(2) Background and Analysis

(a) Methodology for Lake Classification

In the January 2010 proposal, EPA used color and alkalinity to classify Florida's lakes based on substantial data demonstrating that these characteristics influence the response of lakes to increased nitrogen/phosphorus and the expected background chlorophyll *a* concentration. Many of Florida's lakes contain dissolved organic matter leached from surface vegetation that

[128] The previous three years of data are required as a basis for modifying TN and TP criteria and must meet FDEP's data quality assurance objectives. Additional historical data may be used to augment the three years of data characterizing the lake's annual and inter-annual variability. Only historical data containing data for all three parameters can be used and the data must meet FDEP's data quality assurance objectives.

[129] As noted above, if more than three years of data are available for each parameter, then more data can be used.

[130] Approximately 30% of Florida lakes are fed by streams to which this DPV analysis would apply (Schiffer, Donna M. 1998. *Hydrology of Central Florida Lakes—A Primer.* U.S. Geological Survey in cooperation with SJWMD and SFWMD: Circular 1137).

[131] Kennedy, R.H. 1995. *Application of the BATHTUB model to Selected Southeastern Reservoirs.* Technical Report EL–95–14. U.S. Army Engineer Waterways Experiment Station, Vicksburg, MS.; Walker, W.W., 1985. *Empirical Methods for Predicting Eutrophication In Impoundments; Report 3, Phase II: Model Refinements.* Technical Report E–81–9. U.S. Army Engineer Waterways Experiment Station, Vicksburg, MS.; Walker, W.W., 1987. *Empirical Methods for Predicting Eutrophication in Impoundments; Report 4, Phase III: Applications Manual.* Technical Report E–81–9. U.S. Army Engineer Waterways Experiment Station, Vicksburg, MS.

colors the water. More color in a lake limits light penetration within the water column, which in turn limits algal growth. Thus, in lakes with colored water, higher levels of nitrogen/phosphorus may occur without exceeding the chlorophyll *a* criteria concentrations. EPA evaluated relationships among TN, TP, and chlorophyll *a* concentration data, and found that lake color influenced these relationships. More specifically, EPA found the correlations between nitrogen/phosphorus and chlorophyll *a* concentrations to be stronger and less variable when lakes were categorized into two distinct groups based on a color threshold of 40 PCU, with clear lakes demonstrating more algal growth with increased nitrogen/phosphorus, as would be predicted by the increased light penetration. This threshold is consistent with the distinction between clear and colored lakes long observed in Florida.[132]

Within the clear lakes category, color is not the dominant controlling factor in algal growth. For these clear lakes, EPA proposed the use of alkalinity as an additional distinguishing characteristic. Alkalinity and pH increase when water is in contact with carbonate rocks, such as limestone, or limestone-derived soil in the State of Florida. Limestone is also a natural source of phosphorus, and thus, in Florida, lakes that are higher in alkalinity are often associated with naturally elevated TP levels. The alkalinity (measured as $CaCO_3$ concentration) of Florida clear lakes ranges from zero to over 200 mg/L. EPA proposed classifying clear Florida lakes into acidic and alkaline classes based on an alkalinity threshold of 50 mg/L $CaCO_3$, and solicited comment on whether a 20 mg/L $CaCO_3$ threshold would be more appropriate. EPA received comments noting that that the lower alkalinity classification threshold would be more representative of naturally oligotrophic conditions by creating a class of lakes with very low alkalinity and correspondingly low chlorophyll *a* concentrations. After reviewing available lake data, EPA found that clear lakes below 20 mg/L $CaCO_3$ were more similar to one another in terms of naturally expected chlorophyll *a*, TN, and TP concentrations than clear lakes below 50 mg/L $CaCO_3$. Thus, EPA concluded that an alkalinity threshold of 20 mg/L $CaCO_3$ was an appropriate threshold for classifying clear lakes and EPA is finalizing the lower alkalinity threshold in this rule. More information on this specific topic is provided in EPA's Finals TSD for Florida's Inland Waters, Chapter 2: Methodology for Deriving U.S. EPA's Criteria for Lakes located in the record for this final rule.

EPA also proposed the use of specific conductance as a surrogate for alkalinity. EPA received comments that conductivity was not an accurate surrogate measure for alkalinity. EPA evaluated the association between specific conductivity and alkalinity and concluded that alkalinity is a preferred parameter for lake classification because it is a more direct measure of the presence of carbonate rocks, such as limestone that are associated with natural elevated phosphorus levels. Changes in specific conductivity can be attributed to changes in alkalinity, but in many cases may be caused by increases in the concentrations of other compounds that originate from human activities. Thus, EPA has concluded that alkalinity is a more reliable indicator for characterizing natural background conditions for Florida lakes.

A number of comments suggested EPA consider a system that delineates 47 lake regions and a system that classifies lakes as a continuous function of both alkalinity and color. As discussed in more detail in the TSD supporting this final rule, EPA evaluated each of these alternative classification approaches, and found that they did not improve the predictive accuracy of biological responses to nitrogen/phosphorus over EPA's classification, nor result in a practical system that can be implemented by FDEP. For example, in the case of the 47 lake region approach, insufficient data are available to derive numeric criteria across all of the 47 regions and in the case of the continuous function approach there is a reliance on an assumption that TN and TP are always co-limiting that is not always true.[133]

A number of commenters suggested that lake-specific criteria would be more appropriate than the three broad classes that EPA proposed. The substantial data available in the record for this final rule supports the conclusion that many of Florida's lakes share similar physical, chemical, and geological characteristics, which in turn justifies, based on sound scientific evidence, broad classification of Florida lakes. EPA concluded, based on the substantial data and associated analysis explained above, that color and alkalinity are primary distinguishing factors in Florida lakes with respect to nitrogen/phosphorus dynamics and the associated biological response. With respect to consideration of site-specific information that goes beyond the detailed site-specific sampling and monitoring analysis already discussed,[134] the numeric lake criteria in this final rule are established within a flexible regulatory framework that allows adjustment of TN, TP, and/or chlorophyll *a* criteria based on additional lake-specific data. This framework provides an opportunity to derive lake-specific criteria similar to the manner suggested in public comment, where lake-specific data and information are available, while ensuring that numeric criteria are in place to protect all of Florida's lakes. Further site-specific flexibility is provided in this final rule through the derivation of alternative criteria by a Federal Site Specific Adjusted Criteria (SSAC) process discussed in more detail below in Section V.C.

In this final rule, EPA is dividing Florida's lakes into three classes: (1) Colored Lakes >40 Platinum Cobalt Units (PCU), (2) Clear, High Alkalinity Lakes (≤40 PCU with alkalinity >20 mg/L calcium carbonate ($CaCO_3$)), and (3) Clear, Low Alkalinity Lakes (≤40 PCU with alkalinity ≤20 mg/L $CaCO_3$). These two parameters, color and alkalinity, both affect lake productivity and plant biomass, as measured by chlorophyll *a*. For more information regarding these classes, please refer to EPA's Final Rule TSD for Florida's Inland Waters, Chapter 2: Methodology for Deriving U.S. EPA's Criteria for Lakes.

(b) Methodology for Chlorophyll *a* Criteria

EPA proposed the use of chlorophyll *a* concentration as an indicator of a healthy biological condition, supportive of natural balanced populations of aquatic flora and fauna in each of the classes of Florida's lakes. Excess algal growth is associated with degradation in aquatic life, and chlorophyll *a* levels are a measure of algal growth. To derive the proposed chlorophyll *a* concentrations that would be protective of natural balanced populations of aquatic flora and fauna in Florida's lakes, EPA utilized the expected trophic status of the lake, based on internationally accepted lake use classifications.[135]

[132] Shannon, E.E., and P.L. Brezonik. 1972. Limnological characteristics of north and central Florida lakes. Limnology and Oceanography 17(1): 97–110.

[133] Guildford, S. J. and R. E. Hecky. 2000. Total nitrogen, total phosphorus, and nutrient limitation in lakes and oceans: Is there a common relationship? *Limnology and Oceanography* 45: 1213–1223.

[134] Technical Support Document for EPA's Final Rule for Numeric Nutrient Criteria for Nitrogen/Phosphorus Pollution in Florida's Inland Surface Fresh Waters.

[135] OECD. 1982. *Eutrophication of Waters. Monitoring, Assessment and Control.* Organisation

Continued

As discussed in more detail at proposal, lakes can be classified into one of three trophic State categories (*i.e.*, oligotrophic, mesotrophic, eutrophic).[136] EPA concluded at proposal that healthy colored lakes and clear, high alkalinity lakes should maintain a mesotrophic status, because they receive significant natural nitrogen/phosphorus input and still support a healthy diversity of aquatic life in warm, productive climates such as Florida. For these two categories of lakes, EPA proposed a chlorophyll *a* criterion of 0.020 mg/L to support balanced natural populations of aquatic life flora and fauna. At concentrations above 0.020 mg/L chlorophyll *a*, the trophic status of the lake is more likely to become eutrophic and the additional chlorophyll *a* will reduce water clarity, negatively affecting native submerged macrophytes, and the invertebrate and fish communities that depend on them. Commenters suggested that this threshold is overly protective of naturally eutrophic lakes in the State. For those lakes that may currently be naturally eutrophic, this final rule contains a formal SSAC process to revise these criteria for this unique type of lake. For more information on the SSAC process, please refer to Section V.C of this final rule.

In contrast, clear, low alkalinity lakes in Florida do not receive natural nitrogen/phosphorus input from underlying geological formations in the watershed and thus, they support less algal growth and have lower chlorophyll *a* levels than colored or clear, high alkalinity lakes. EPA concluded at proposal that these lakes should maintain an oligotrophic status to support balanced natural populations of aquatic flora and fauna. EPA proposed a chlorophyll *a* criterion of 0.006 mg/L in clear, low alkalinity lakes to support balanced natural populations of aquatic life flora and fauna. At concentrations above 0.006 mg/L chlorophyll *a*, the trophic status of the lake is more likely to become mesotrophic and the additional chlorophyll *a* will reduce water clarity, negatively affecting native submerged macrophytes, and the invertebrate and fish communities that depend on them. Commenters suggested that this chlorophyll *a* concentration may not be appropriate for clear lakes with alkalinity less than 50 mg/L. As explained in more detail above, in this final rule EPA concluded that 20 mg/L is an appropriate threshold between low and high alkalinity lakes. Thus, lakes with alkalinity greater than 20 mg/L will have a chlorophyll *a* criterion that is applicable to clear, high alkalinity lakes. Based on the revision of the alkalinity threshold to 20 mg/L, EPA reviewed the available chlorophyll *a* data for clear, low alkalinity lakes and found that the majority of lakes have chlorophyll *a* concentrations less than 0.006 mg/L reflective of oligotrophic conditions which leads EPA to conclude that this chlorophyll *a* concentration will serve to maintain the trophic status of these lakes.

In this final rule, EPA is promulgating chlorophyll *a* criteria of 0.020 mg/L in colored lakes and clear, high alkalinity lakes and a chlorophyll *a* criterion of 0.006 mg/L in clear, low alkalinity lakes as an indicator of a healthy biological condition, supportive of natural balanced populations of aquatic flora and fauna in these classes of Florida's lakes. For more information regarding these chlorophyll *a* criteria, please refer to EPA's Final Rule TSD for Florida's Inland Waters, Chapter 2: Methodology for Deriving U.S. EPA's Criteria for Lakes.

(c) Methodology for Total Nitrogen (TN) and Total Phosphorus (TP) Criteria in Lakes

EPA proposed TN and TP criteria for each of the classes of lakes described in Section III.C(2)(a) based on the response of chlorophyll *a* to increases in TN and TP for clear and colored lakes in Florida. These responses were quantitatively estimated with linear regressions. Each data point used in estimating the statistical relationships was the geometric mean of samples taken over the course of a year in a particular Florida lake. Statistical analyses of these relationships showed that the chlorophyll *a* responses to changes in TN and TP differed for colored versus clear lakes, as would be expected, because color blocks light penetration in the water column and limits algal growth. These analyses also showed that chlorophyll *a* responds to changes in TN and TP in high and low alkalinity clear lakes similarly, as would be expected, because alkalinity does not affect light penetration. These relationships were used to derive TN and TP criteria that would maintain chlorophyll *a* concentrations at desired levels known to be supportive of balanced natural populations of aquatic flora and fauna as discussed above. These analyses are explained in more detail in EPA's Final Rule TSD for Florida's Inland Waters, Chapter 2: Methodology for Deriving U.S. EPA's Criteria for Lakes included in the record for this final rule.

EPA proposed baseline TN and TP criteria based on the 75th percentile of the predicted distribution of chlorophyll *a* concentrations, given a TN or TP concentration. Commenters suggested alternative approaches for deriving TN and TP criteria, including using either the mean predicted chlorophyll *a* concentration, using the 25th percentile of the predicted distribution of chlorophyll *a* concentrations, and using an additional criterion based on a higher percentile that is associated with a different exceedance frequency. EPA considered these alternative approaches and concluded that calculating the TN and TP criteria as a baseline concentration with an associated concentration range was a more flexible approach than a single value approach manifested as the TN and TP concentration associated with a specific chlorophyll *a* concentration. Thus, the approach included in this final rule takes into account the natural variability observed in different classes of lakes (*i.e.*, colored or clear) in a way that a single value approach based on the regression line or the lower value of the 50th percentile prediction interval does not.

In this final rule, the TN and TP criteria are based on linear regressions (*i.e.*, best-fit lines) predicting the annual geometric mean chlorophyll *a* concentration as a function of the annual geometric mean TN or TP. Baseline TN and TP criteria are calculated as the point at which the 75th percentile of the predicted distribution of chlorophyll *a* concentrations from the regression relationship is equivalent to the chlorophyll *a* criterion for the appropriate lake class. The range of values in the predicted distribution of chlorophyll *a* concentrations arises from small differences in the nitrogen/phosphorus–chlorophyll *a* relationships across different lakes and variability in these relationships between years in the same lake. Hence, TN and TP criteria are based on the 75th percentile that will be protective at the majority of lakes and in the majority of years.

The predicted distribution of chlorophyll *a* concentrations for lakes differs inherently from the distribution of TN and TP concentrations calculated from reference sites for criteria for Florida streams (Section III.B(2)(b)). In the case of the criteria for Florida streams for most NWRs, benchmark sites represent a population of least-

for Economic Development and Co-Operation, Paris, France.

[136] Trophic state describes the nitrogen/phosphorus levels and algal state of an aquatic system: Oligotrophic (low nitrogen/phosphorus and algal productivity), mesotrophic (moderate nitrogen/phosphorus and algal productivity), and eutrophic (high nitrogen/phosphorus and algal productivity).

disturbed sites and the criteria based on the 90th percentile of nitrogen and phosphorus concentrations from these sites are selected to characterize the upper bound of nitrogen/phosphorus concentrations that one would expect from such sites. Criteria for Florida lakes rely on a predictive relationship between nitrogen/phosphorus and chlorophyll *a* concentrations, and the 75th percentile is selected from the distribution of chlorophyll *a* concentrations predicted for *specific* concentrations of TN and TP. As discussed above, basing criteria on this percentile provides a means of accounting for variability in chlorophyll *a* concentrations predicted for a given TN and TP concentration. In short, the percentile for the streams criteria is selected to ensure that nitrogen/phosphorus concentrations in all streams are at least as low as those observed in reference streams, whereas the percentile for the lakes criteria is selected such that concentrations appropriately account for variability in the relationships between nitrogen/phosphorus and chlorophyll *a* concentrations.

(d) Duration and Frequency

Aquatic life water quality criteria include magnitude, duration, and frequency components. For the chlorophyll *a*, TN, and TP criteria for lakes, the criterion-magnitude values, expressed as a concentration, are provided in Table C–1 in bold. The criterion-duration of this magnitude is specified in a footnote to this Table as an annual geometric mean. EPA is finalizing the criterion-frequency as a no-more-than-once-in-three-years excursion frequency of the annual geometric mean criteria for lakes. The duration component of the criteria is based on annual geometric means to be consistent with the data set used to derive these criteria, which applied stressor-response relationships based on annual geometric means for individual years at individual lakes. These selected duration and frequency components recognize that hydrological variability (*e.g.*, high and low flows) will produce variability in nitrogen and phosphorus concentrations, and that individual measurements may at times be greater than the criterion-magnitude concentrations without causing unacceptable effects to aquatic organisms and their uses. Furthermore, they balance the representation of the central tendency of the predicted relationship between TN or TP and chlorophyll *a* based from many years of data with the need to exercise some caution to ensure that lakes have sufficient time to process individual years of elevated nitrogen and phosphorus concentrations and avoid the possibility of cumulative and chronic effects (*i.e.*, the no-more-than-one-in-three-year component). Additionally, because nitrogen/phosphorus pollution is best managed on a watershed basis, this is the same frequency and duration used in the final streams criteria. More information on this specific topic is provided in EPA's Final Rule TSD for Florida's Inland Waters, Chapter 2: Methodology for Deriving U.S. EPA's Criteria for Lakes located in the record for this final rule.

(e) Application of Lake-Specific, Ambient Condition-Based Modified TN and TP Criteria

EPA proposed an accompanying approach that the State could use to adjust TN and TP criteria for a particular lake within a certain range where sufficient data on long-term ambient chlorophyll *a*, TN and TP levels are available to demonstrate that protective chlorophyll *a* criterion for a specific lake will still be maintained and a balance of natural populations of aquatic flora and fauna will be supported. This approach allows for readily available site-specific data to be taken into account in the expression of TN and TP criteria, while still ensuring support of balanced natural populations of aquatic flora and fauna by maintaining the associated chlorophyll *a* level at or below the chlorophyll *a* criterion level. The scientific premise for the lake-specific ambient calculation provision for modified TN and/or TP criteria is that if ambient lake data show that a lake's chlorophyll *a* levels are at or below the established criteria (*i.e.*, magnitude) for at least the last three years and its TN and/or TP levels are within the lower and upper bounds, then those ambient levels of TN and TP represent conditions that will continue to support the specified chlorophyll *a* response level. The lower bound of the range is based on the TN/TP values that correspond to the 75th percentile of the predicted chlorophyll *a* distribution and the upper bound of the range is based on the TN/TP values that correspond to the 25th percentile of the same predicted distribution. The use of the 25th and 75th percentiles accounts for the majority of variability that may occur around the central tendency of the predicted relationship between TN or TP and chlorophyll *a*.

This final rule provides that FDEP must establish and document these modified criteria in a manner that clearly recognizes their status as the applicable criteria for a particular lake. To this end, FDEP must submit a letter to EPA Region 4 formally documenting the use of modified criteria as the applicable criteria for particular lakes. This final rule allows for a one-time adjustment without a requirement that FDEP go through a formal SSAC process. EPA believes that such modified TN and TP criteria do not need to go through the SSAC process because the conditions under which they are applicable are clearly stated in this final rule and data requirements are clearly laid out so that the outcome is clear, consistent, transparent, and reproducible. By providing a specific process for deriving modified criteria within the WQS rule itself, each individual outcome of this process is an effective WQS for CWA purposes and does not need separate adoption by FDEP or approval by EPA. For more information on the SSAC process, please refer to Section V.C of this final rule.

Application of the ambient calculation provision has implications for assessment and permitting because the outcome of applying this provision is to establish alternate numeric TN and/or TP values as the applicable lake criteria. For accountability and tracking purposes, the State must document the result of the ambient calculation for any given lake. Once modified criteria are established under this approach, they remain the applicable criteria for the long-term for purposes of implementing the State's water quality program until they are subsequently modified either through the Federal SSAC process or State revision to the applicable WQS, which has been approved by EPA pursuant to CWA section 303(c).

This site-specific lake criteria adjustment provision is subject to the downstream protection requirements more broadly discussed below. Thus in a comparable manner this final rule provides that calculated TN and/or TP values in a lake that discharges to a stream may not exceed criteria applicable to the stream to which a lake discharges.

(f) Downstream Protection of Lakes

In developing the proposed stream criteria, EPA also evaluated their effectiveness for assuring the protection of downstream lake water quality standards pursuant to the provisions of 40 CFR 130.10(b), which requires that WQS must provide for the attainment and maintenance of the WQS of downstream waters.[137] EPA's criteria for

[137] EPA will assess the effectiveness of final stream criteria for assuring the protection of

Continued

lakes are, in some cases, more stringent than the final criteria for streams that flow into the lakes, and thus the instream criteria may not be stringent enough to ensure protection of WQS in certain downstream lakes. As a result, EPA proposed application of the Vollenweider equation to ensure that the TP criteria in streams are protective of downstream lakes, and requested comment on alternative approaches such as the BATHTUB model and whether there should be an allowance for use of other models that are demonstrated to be protective and scientifically defensible.

The proposed use of the Vollenweider model equation to ensure the protection of downstream lakes requires input of two lake-specific characteristics: the fraction of inflow due to stream flow and the hydraulic retention time. EPA provided alternative preset values for percent contribution from stream flow and hydraulic retention time that could be used in those instances where lake-specific input values are not readily available. EPA's January 2010 proposed rule discussed the flexibility for the State to use site-specific inputs to the Vollenweider equation for these two parameters, as long as the State determines that such inputs are appropriate and documents the site-specific values. Some commenters stated that the Vollenweider equation is overly simplistic and does not include the necessary factors to account for physical, hydrologic, chemical, and biological processes necessary to determine protective criteria. Several commenters also suggested the need for TN values to protect downstream lakes that are nitrogen-limited (such as many of the lakes in the phosphorus-rich areas of the State). Comments included a recommendation to use models that can better represent site-specific conditions, such as BATHTUB.

EPA's August 2010 Supplemental Notice of Data Availability and Request for Comment requested additional comment on using the BATHTUB model in place of the Vollenweider equation for deriving both TP and TN criteria to protect downstream lakes, allowing the use of alternative models under certain circumstances, and providing for an alternative approach to protect downstream lakes when limited data are available that would use the lake criteria themselves as criteria for upstream waters flowing into the lake.

In the final rule, protection of downstream lakes is accomplished through establishment of a downstream protection value (DPV). The applicable criteria for streams that flow into downstream lakes include both the instream criteria for TN and TP and the DPV, which is a concentration or loading value at the point of entry into a lake that results in attainment of the lake criteria. EPA selected the point of entry into the lake, also referred to as the "pour point," as the location to measure water quality because the lake responds to the input from the pour point and all contributions from the stream network above this point in a watershed affect the water quality at the pour point. When a DPV is exceeded at the pour point, the waters that collectively comprise the network of streams in the watershed above that pour point are considered to not attain the DPV for purposes of section 303(d) of the Clean Water Act. The State may identify these impaired waters as a group rather than individually.

It is appropriate to express the DPV as either a load or concentration (load divided by flow) because both are expressions of the amount of TN and TP that are delivered to the downstream water. In an expression of load, the amount is expressed directly as mass per time (*e.g.*, pounds per year), whereas a concentration expresses the amount in terms of the mass contained in a particular volume of water (*e.g.*, milligrams per liter). Either expression may be used for assessment and source control allocation purposes. Calculating a DPV as a load will require modeling or other technical information, such as a TMDL, that accounts for both the volume of the receiving water and the flow contributed through the pour point. A DPV expressed as a concentration may be based on a model or TMDL or may reflect a TN or TP level that corresponds to a TN, TP, or chlorophyll *a* concentration that protects the lake.

Contributions of TN and/or TP from sources in stream tributaries upstream of the point of entry are accountable to the DPV because the water quality in the stream tributaries must result in attainment of the DPV at the pour point into the lake. The spatial allocation of load within the watershed is an important accounting step to ensure that the DPV is achieved at the point of entry into the lake. How the watershed load is allocated may differ based on watershed characteristics and existing sources (*e.g.*, areas that are more susceptible to physical loss of nitrogen; location of towns, farms, and dischargers), so long as the DPV is met at the point of entry into the downstream lake. Where additional information is available, watershed modeling could be used to develop allocations that reflect hydrologic variability and other water quality considerations. For protection of the downstream lake, what is important is an accounting for nutrient loadings on a watershed scale that results in meeting the DPV at the point of entry into the downstream lake.

The final rule provides that additional DPVs may be established in upstream locations to represent sub-allocations of the total allowable loading or concentration. Such sub-allocations may be useful where there are differences in hydrological conditions and/or sources of TN and/or TP in different parts of the watershed. The rule specifies that DPVs apply to stream tributaries up to the point of reaching a waterbody that is not a stream as defined in the rule (*e.g.*, up to reaching another lake in a "nested" or chain of lakes situation). The rule also includes an option, however, to establish a DPV to account for a larger watershed area in a modeling context. Establishing DPVs that apply to a larger watershed may be useful to address a situation where the water that is furthest downstream in a watershed is also the water that is most sensitive to nitrogen/phosphorus pollution. That situation may require a more equitable distribution, across the larger watershed, of the load that protects the most sensitive waterbody.

Where multiple tributaries enter a lake, the total allowable loading to the lake may be distributed among the tributaries for purposes of DPV calculation in any manner that results in meeting the total allowable loading for the lake, remembering that those tributaries are also subject to the instream protection value established for the tributaries.

Where sufficient data and information are available, DPVs may be established through application of the BATHTUB model. BATHTUB applies empirical models to morphometrically complex lakes and reservoirs. The model performs steady-state water and nutrient balance calculations, uses spatially segmented hydraulic networks, and accounts for advective and diffusive transport of nutrients. When properly calibrated and applied, BATHTUB predicts nutrient-related water quality conditions such as TP, TN, and chlorophyll *a* concentrations, transparency, and hypolimnetic oxygen depletion rates. The model can apply to a variety of lake sizes, shapes and transport characteristics. A high degree of flexibility is available for specifying

downstream estuaries in a separate rulemaking that focuses on estuarine and coastal waters to be proposed by November 14, 2011 and finalized by August 15, 2012.

model segments as well as multiple influent streams. Because water quality conditions are calculated using relationships derived from data specific to each lake, BATHTUB accounts for differences between lakes, such as the rate of internal loading of phosphorus from bottom sediments. The above descriptive information is summarized from available technical references that also describe the model and its applications in greater detail.[138] [139] [140] EPA believes BATHTUB is appropriate for DPV calculations because BATHTUB can represent a number of site-specific variables that may influence nutrient responses and can estimate both TN and TP concentrations at the pour points to protect the receiving lake. BATHTUB has been previously used for lake water quality management purposes, such as the development of TMDLs in States, including Florida. This model was selected because it does not have extensive data requirements, yet it provides for the capability to be calibrated based on observed site-specific lake data and it provides for reliable estimates that will ensure the protection of downstream lakes.

EPA's final rule also specifically authorizes FDEP or EPA to use a model other than BATHTUB when either FDEP or EPA determines that it would be appropriate to use another scientifically defensible modeling approach that results in the protection of downstream lakes. While BATHTUB is a peer-reviewed and versatile model, there are other models that, when appropriately calibrated and applied, can offer additional capability to address complex situations with an even greater degree of site-specificity. Adopted and approved TMDLs may contain sufficient information to support derivation of a DPV when the TMDL is based on relevant data, defensible science, and accurate analysis.

As discussed in more detail in the Agency's August 2010 Supplemental Notice of Data Availability and Request for Comment on this issue, one example of an alternative model that FDEP or EPA might consider using for particularly complex site-specific conditions is the Water Quality Analysis Simulation Program (WASP) model. This model allows users to conduct detailed simulations of water quality responses to natural and manmade pollutant inputs. WASP is a dynamic compartment-modeling program for aquatic systems, including both the water column and the underlying benthos. WASP allows the user to simulate systems in 1, 2, or 3 dimensions, and a variety of pollutant types. The model can represent time varying processes of advection, dispersion, point and diffuse mass loading, and boundary exchange. WASP also can be linked with hydrodynamic and sediment transport models that can provide flows, depths, velocities, temperature, salinity and sediment fluxes. The above summary information as well as additional technical information may be found at *http://www.epa.gov/athens/wwqtsc/html/wasp.html*. Like BATHTUB, WASP has also been previously used for lake water quality management purposes, such as TMDLs, nationally and in the State of Florida. This model is different from BATHTUB because it does have extensive data requirements that allow for the capability to be finely calibrated based on observed site-specific lake data, but is similar to BATHTUB in that it also provides for reliable estimates that will ensure the protection of downstream lakes.

EPA is finalizing a provision in this section of the rule for situations where data are not readily available to derive TN and/or TP DPVs using BATHTUB or another scientifically defensible model. In that situation, the rule describes how DPVs are determined where the downstream lake is attaining the lake criteria and where the downstream lake is either not assessed or is impaired.

Where sufficient information is not available to derive TN and/or TP DPVs using BATHTUB or another scientifically defensible technical model and the lake attains the applicable criteria, the DPVs would be the associated ambient instream levels of TN and/or TP at the point of entry into the lake. As long as the TN and TP concentrations necessary to support a balanced natural population of aquatic flora and fauna in the downstream lake are maintained in the inflow from streams, this approach will provide adequate protection of downstream lakes and would be used as the applicable DPVs in the absence of readily available data to support derivation of TN and TP DPVs using BATHTUB or another scientifically defensible technical model such as WASP.

EPA's final rule provides that when the DPV is based on the ambient condition associated with attainment of criteria in the downstream lake, degradation in water quality from those established levels would be considered impairment, unless the State or EPA revises the DPV using a modeling approach or TMDL to show that higher levels of nutrient contribution from the tributaries would still result in attainment of applicable lake criteria. This provision is not intended to limit growth and/or development in the watershed, nor intended to maintain current conditions regardless of further analysis. Rather this provision is intended to ensure that WQS are not only restored when found to be impaired, but are in fact maintained when found to be attained, consistent with the goals of the Clean Water Act. Higher levels of TN and/or TP may be allowed in such watersheds where it is demonstrated that such higher levels will fully protect the lake's WQS.

Where sufficient information is not available to derive TN and/or TP DPVs using BATHTUB or another scientifically defensible technical model and the lake does not attain the applicable TN, TP, and/or chlorophyll *a* criteria or is un-assessed, lake criteria values for TN and/or TP are to be used as the DPVs. EPA believes that this approach is protective because the TN and TP concentrations entering the lake are unlikely to need to be lower than the criterion concentration necessary to be protective of the lake itself.

(g) Stressor-Response Approach

In deriving the final criteria for lakes, EPA has relied on a stressor-response approach which has been well documented and developed in a number of different contexts.[141] [142] [143] Stressor-response approaches estimate the relationship between nitrogen/phosphorus concentrations and a response measure that is either directly or indirectly related to the designated use (in this case, chlorophyll *a* as a measure of attaining a balanced natural population of aquatic flora and fauna). Then, concentrations that support the

[138] Walker, W.W., 1981. *Empirical Methods for Predicting Eutrophication In Impoundments; Report 1, Phase I: Data Base Development.* Technical Report E–81–9. U.S. Army Engineer Waterways Experiment Station, Vicksburg, MS.

[139] Walker, W.W., 1982. *Empirical Methods for Predicting Eutrophication In Impoundments; Report 2, Phase II: Model Testing.* Technical Report E–81–9. U.S. Army Engineer Waterways Experiment Station, Vicksburg, MS.

[140] Walker, W.W., 1999. *Simplified Procedures for Eutrophication Assessment and Prediction: User Manual;* Instruction Report W–96–2. U.S. Army Corps of Engineers Waterways Experiment Station, Vicksburg, MS.

[141] USEPA. 2000a. *Nutrient Criteria Technical Guidance Manual: Lakes and Reservoirs.* EPA–822–B–00–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[142] USEPA. 2000b. *Nutrient Criteria Technical Guidance Manual: Rivers and Streams.* EPA–822–B–00–002. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[143] USEPA. 2008. *Nutrient Criteria Technical Guidance Manual: Wetlands.* EPA–822–B–08–001. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

designated use can be derived from the estimated relationship. In the case of Florida, the use of this approach is supported by a substantial Florida-specific database of high quality information, sound scientific analysis and technical evaluation.

The effects of nitrogen/phosphorus pollution are manifested in lakes in a variety of ways and are well-documented.[144] [145] [146] [147] A common effect of nitrogen/phosphorus pollution in lakes is the over-stimulation of algal growth resulting in algal blooms, which can cause changes in algal and animal assemblages due to adverse changes in important water quality parameters necessary to support aquatic life. Algal blooms can decrease water clarity and aesthetics, which in turn can affect the suitability of a lake for primary (*e.g.*, swimming) and secondary (*e.g.*, boating) contact recreation. Algal blooms can adversely affect drinking water supplies by releasing toxins, interfering with disinfection processes, or requiring additional treatment. Algal blooms can adversely affect biological process by decreasing light availability to submerged aquatic vegetation (which serves as habitat for aquatic life), degrading food quality and quantity for other aquatic life, and increasing the rate of oxygen consumption.

D. Numeric Criterion for the State of Florida's Springs

(1) Final Rule

EPA defines "spring" as a site at which ground water flows through a natural opening in the ground onto the land surface or into a body of surface water. This definition is drawn from the U.S. Geological Survey, Circular 1137.[148] This definition is not intended to include streams that flow in a defined channel that have some groundwater baseflow component. EPA recognized that groundwater-surface water interactions in Florida are complex and that FDEP will need to make site-specific determinations about whether water is subject to the stream criteria or the springs criterion. EPA is promulgating the numeric criterion for nitrate+nitrite for Florida's springs classified as Class I or III waters under Florida law (Section 62–302.400, F.A.C.):

The applicable nitrate (NO_3^-) + Nitrite (NO_2^-) is 0.35 mg/L as an annual geometric mean, not to be exceeded more than once in a three-year period

(2) Background and Analysis

(a) Derivation of Nitrate + Nitrite Criterion

In its January proposal, EPA proposed a nitrate+nitrite criterion of 0.35 mg/L for springs and clear streams that would support balanced natural populations of aquatic flora and fauna in springs. EPA proposed criteria for nitrate+nitrite because one of most significant factors causing adverse changes in spring ecosystems is the pollution of groundwater, principally with nitrate+nitrite, resulting from human land use changes, cultural practices, and significant population growth.[149] [150]

EPA based its proposed criterion on multiple lines of stressor-response evidence, which included controlled, laboratory-scale experimental data and analysis of field-based data. EPA's first line of evidence is stressor-response data from controlled laboratory experiments, which studied the growth response of algae in springs to different concentrations of nitrate+nitrite. EPA found in its review of comprehensive surveys [151] [152] and a study [153] of 29 Florida springs at over 150 sampling sites, conducted on behalf of FDEP over three years, that two nuisance algal taxa, the cyanobacterium *Lyngbya wollei* and the macroalgae *Vaucheria sp.*, were the most commonly occurring taxa. The authors of the study conducted controlled laboratory experiments, which tested the growth response of *Lyngbya wollei* and *Vaucheria sp.* to different doses of nitrate+nitrite. They found that *Lyngbya wollei* and *Vaucheria sp.* growth rates increased in response to increased doses of nitrate+nitrite and that most of their highest growth rates were reached at and above 0.23 mg/L nitrate+nitrite. EPA interpreted the results from these studies as strong empirical evidence of a stressor-response relationship between nuisance algae and nitrate+nitrite and further indicated specific concentrations above which undesirable growth of nuisance algal may be likely to occur.

In addition to the laboratory-based experimental evidence, EPA reviewed information compiled by FDEP in its assessment of limits to restore springs and protect them from excess algal growth.[154] [155] The second line of evidence was based on data collected from *in-situ* algal monitoring and long-term field surveys in rivers FDEP considered to exhibit similar aquatic conditions to springs (*e.g.*, algal communities, water clarity, and proportion of flow coming from a spring). EPA found additional stressor-response evidence in an analysis [156] based on over 200 algal samples collected from 13 different algal monitoring stations along the Suwannee, Santa Fe, and Withlacoochee Rivers from 1990 to 1998. The analysis examined algal growth response over a range of nitrate+nitrite concentration. Results indicated a sharp increase in

[144] Lee, G.F., W. Rast, R.A. Jones. 1978. Eutrophication of water bodies: Insights for an age-old problem. *Environmental Science and Technology* 12: 900–908.

[145] Carlson R.E. 1977. A trophic state index for lakes. *Limnology and Oceanography* 22:361–369.

[146] Smith, V.H., G.D. Tilman, and J.C. Nekola. 1999. Eutrophication: impacts of excess nutrient inputs on freshwater, marine, and terrestrial ecosystems. *Environmental Pollution* 100: 179–196.

[147] Smith, V.H., S.B. Joye, and R.W. Howarth. 2006. Eutrophication of freshwater and marine ecosystems. *Limnology and Oceanography* 51:351–355.

[148] Schiffer, Donna M. 1998. *Hydrology of Central Florida Lakes—A Primer.* U.S. Geological Survey in cooperation with SJWMD and SFWMD: Circular 1137.

[149] Katz, B.G., H.D. Hornsby, J.F. Bohlke and M.F. Mokray. 1999. *Sources and chronology of nitrate contamination in spring water, Suwannee River Basin, Florida.* Water-Resources Investigations Report 99–4252. U.S. Geological Survey, Tallahassee, FL. Available electronically at: *http://fl.water.usgs.gov/PDF_files/wri99_4252_katz.pdf.*

[150] Brown M.T., K. Chinners Reiss, M.J. Cohen, J.M. Evans, P.W. Inglett, K. Sharma Inglett, K. Ramesh Reddy, T.K. Fraze, C.A. Jacoby, E.J. Phlips, R.L. Knight, S.K. Notestein, R.G. Hamann, and K.A. McKee. 2008. *Summary and Synthesis of the Available Literature on the Effects of Nutrients on Spring Organisms and Systems.* University of Florida, Gainesville, Florida. Available electronically at: *http://www.dep.state.fl.us/springs/reports/files/UF_SpringsNutrients_Report.pdf.* Accessed October 2010.

[151] Pinowska, A., R.J. Stevenson, J.O. Sickman, A. Albertin, and M. Anderson. 2007a. *Integrated interpretation of survey for determining nutrient thresholds for macroalgae in Florida Springs: Macroalgal relationships to water, sediment and macroalgae nutrients, diatom indicators and land use.* Florida Department of Environmental Protection, Tallahassee, FL.

[152] Stevenson, R.J., A. Pinowska, and Y.K. Wang. 2004. *Ecological Condition of Algae and Nutrients in Florida Springs.* Florida Department of Environmental Protection, Tallahassee, FL.

[153] Pinowska, A., R.J. Stevenson, J.O. Sickman, A. Albertin, and M. Anderson. 2007b. *Integrated interpretation of survey and experimental approaches for determining nutrient thresholds for macroalgae in Florida Springs: Laboratory experiments and disturbance study.* Florida Department of Environmental Protection, Tallahassee, FL.

[154] Gao, X. 2008. *Nutrient TMDLs for the Wekiva River (WBIDs 2956, 2956A, and 2956C) and Rock Springs Run (WBID 2967).* Florida Department of Environmental Protection, Division of Water Resource Management, Tallahassee, FL.

[155] Hallas, J.F. and W. Magley. 2008. *Nutrient and Dissolved Oxygen TMDL for the Suwannee River, Santa Fe River, Manatee Springs (3422R), Fanning Springs (3422S), Branford Spring (3422J), Ruth Spring (3422L), Troy Spring (3422T), Royal Spring (3422U), and Falmouth Spring (3422Z).* Florida Department of Environmental Protection, Bureau of Watershed Management, Tallahassee, FL.

[156] Niu, X.-F. 2007. Appendix B. Change Point Analysis of the Suwannee River Algal Data. *In* Gao, X. 2008. *Nutrient TMDLs for the Wekiva River (WBIDs 2956, 2956A, and 2956C) and Rock Springs Run (WBID 2967).* Florida Department of Environmental Protection, Division of Water Resource Management, Tallahassee, FL.

algal abundance and biomass above 0.4 mg/L nitrate + nitrite.

EPA concluded the two different lines of stressor-response evidence point to a nitrate+nitrite concentration of 0.35 mg/L that would prevent excess algal growth and be supportive of balanced natural populations of aquatic flora and fauna in Florida springs. This concentration is higher than that observed in laboratory-scale experiments that may not be closely representative of reference spring sites in Florida, but lower than the concentration that was associated with changes in the balance of natural populations of aquatic flora and fauna observed in an analysis of field data. EPA believes a nitrate+nitrite criterion set at 0.35 mg/L represents an appropriate and reasonable balance of the scientific evidence.

EPA received a number of comments regarding EPA's proposed criterion for springs, including concerns that the biological responses observed in the field were not representative of all springs in Florida. EPA disagrees with these commenters who suggested that the observed effects in the field are not sufficient evidence to support numeric criteria derivation in springs. The algal taxa, *Lyngbya sp.* and *Vaucheria sp.*, are representative taxa found in Florida springs. In fact, *Lyngbya* and *Vaucheria* are the most commonly observed macroalgae in Florida springs.[157] Thus, the Agency considers the biological responses of these representative taxa observed in the field and in laboratory experiments to be ecologically meaningful and indicative of an adverse biological response to elevated nitrate+nitrite concentrations above 0.35 mg/L.

EPA also received comment that the proposed nitrate+nitrite criterion was inappropriately applied to all clear streams within the State. After considering these comments, EPA concluded that clear streams are more appropriately addressed as part of the regionalized reference approach that is supported by a broader range of stream monitoring data as discussed above. Therefore, EPA has decided not to finalize the springs nitrate+nitrite criterion in clear streams because EPA considers the numeric criteria it is finalizing in this rule for streams in the five NWRs, which includes clear streams, to be adequately protective and scientifically defensible. These systems will also be protected from excess nitrogen from groundwater by the nitrate+nitrite criteria applicable in the springs that flow into them; thus, additional nitrate+nitrite criteria are not needed.

In this final rule, EPA is finalizing nitrate+nitrite criterion for springs with a magnitude of 0.35 mg/L. For more information regarding the springs criterion, please refer to EPA's Final Rule TSD for Florida's Inland Waters, Chapter 3: Methodology for Deriving U.S. EPA's Criteria for Springs located in the record for this final rule.

(b) Duration and Frequency

EPA proposed a nitrate+nitrite criterion duration as an annual geometric mean with a criterion frequency of not to be exceeded more than once in three years. EPA also took comment on alternative durations, such as a monthly geometric mean, and alternative frequencies, such as a not to be exceeded more than 10% of the time. EPA considered that the timescales of the algal responses in the laboratory experiments (*i.e.*, 21 to 28 days) might support a shorter duration over which biological response to nitrate+nitrite could occur. However, EPA found in its review of springs data and information that nitrate concentrations can be variable from month to month, and this intra-annual variability was not necessarily associated with impairment of the designated use. Therefore, to account for intra-annual variability, EPA chose to express the nitrate+nitrite criterion for springs on an annual basis. Comments included a suggestion to express the frequency component of the criterion as "not to be exceeded during a three year period as a three year average." However, EPA is concerned that cumulative effects of exposure may manifest themselves in shorter periods of time than three years. This is because springs tend to be clear which provides the opportunity for fast growing nuisance algal species to quickly utilize the excess nitrogen. When nuisance algae species grow prolifically, they outcompete and replace native submerged aquatic vegetation. Thus, more frequent exceedances of the criterion-magnitude will not support a balanced natural population of aquatic flora and fauna in springs because submerged aquatic vegetation can be lost quickly from the effects of nitrate+nitrite pollution, but can take many years, if not decades, to recover.[158] For these reasons, EPA is finalizing the proposed duration and frequency of an annual geometric mean not to be exceeded more than once in three years.

E. Applicability of Criteria When Final

(1) Final Rule

This final rule is effective 15 months after publication in the **Federal Register**, except for the Federal site-specific alternative criteria (SSAC) provision of section 131.43(e), which is effective 60 days after publication in the **Federal Register**. This rule will apply in addition to any other existing CWA-effective criteria for Class I or Class III waters already adopted and submitted to EPA by the State (and for those adopted and submitted to EPA after May 30, 2000, approved by EPA). FDEP establishes its designated uses through a system of classes and Florida waters are designated into one of several different classes. Class III waters provide for healthy aquatic life and safe recreational use. Class I waters include all the protection of designated uses provided for Class III waters, and also include protection for designated uses related to drinking water supply. *See* Section 62-302.400, F.A.C. Class I and III waters, together with Class II waters that are designated for shellfish propagation or harvesting, comprise the set of Florida waters that are assigned designated uses that include the goals articulated in Section 101(a)(2) of the CWA (*i.e.* protection and propagation of fish, shellfish, and wildlife and recreation in and on the water).[159] Class II waters will be covered under EPA's forthcoming rulemaking efforts for estuarine and coastal waters. EPA is promulgating numeric criteria for lakes and flowing waters, consistent with the terms of the Agency's Consent Decree, that Florida has designated as Class I or Class III.

In terms of final rule language, EPA has removed regulatory provisions at 40 CFR 131.43(c)(2)(iii) and 131.43(c)(4)-(6) because these criteria (criteria for protection of downstream estuarine waters, flowing waters in the South Florida Region, and estuaries and coastal waters) will be included with the Agency's 2011 proposed rulemaking for estuarine and coastal waters. For water bodies designated as Class I and Class III predominately fresh waters, EPA's final numeric criteria will be applicable CWA water quality criteria for purposes of implementing CWA programs, including permitting under the NPDES program, as well as

[157] Stevenson, R.J., A. Pinowska, and Y.K. Wang. 2004. *Ecological Condition of Algae and Nutrients in Florida Springs.* Florida Department of Environmental Protection, Tallahassee, FL.

[158] Duarte, C.M. 1995. Submerged aquatic vegetation in relation to different nutrient regimes. *Ophelia: International Journal of Marine Biology* 41: 87-112.

[159] Because FL classifications are cumulative, Class I waters include protections for aquatic life and recreation, in addition to protecting drinking water supply use.

monitoring, assessments, and listing of impaired waters based on applicable CWA WQS and establishment of TMDLs.

In this final rule, the Agency has also deleted proposed regulatory provisions at 40 CFR 131.43(d)(2)(i)–(iii) on mixing zones, design flow, and listing impaired waters. EPA notes that the final criteria in this rule are subject to Florida's general rules of applicability in the same way and to the same extent as are other State-adopted and/or Federally-promulgated criteria for Florida waters. (*See* 40 CFR 131.43(d)(2)). States have discretion to adopt policies generally affecting the application and implementation of WQS. (*See* 40 CFR 131.13). There are many applications of criteria in Florida's water quality programs. Therefore, EPA believes that it is not necessary for purposes of this final rule to enumerate each of them, nor is it necessary to restate any otherwise applicable requirements. This broad reference to general rules of applicability provides sufficient coverage and has been used without further elaboration in EPA's most recent criteria promulgation applicable to State waters.[160] The Agency is also concerned that addressing some applications in this final regulations and not others may create unnecessary and unintended questions, confusion, and uncertainty about the overall application of Florida's general rules.

(2) Summary of Major Comments

Regarding application of criteria, several commenters asked EPA to provide more detail on how waters would be monitored, whether EPA would use the rotating basin approach that FDEP uses, how EPA would enforce the criteria, and how specific entities would be affected. In response, EPA points out that WQS generally, and EPA's rule specifically, do not specify how to achieve those WQS. As discussed above, the State of Florida will determine how best to meet these Federal numeric criteria in a way that most effectively meets the needs of its citizens and environment. FDEP is the primary agency responsible for implementing CWA programs in the State of Florida. As such, EPA defers to FDEP in administering applicable CWA programs consistent with the CWA and EPA's implementing regulations. EPA has worked closely with the State to address nitrogen/phosphorus pollution problems in Florida. EPA will continue to collaborate with FDEP as the State implements EPA's Federally-promulgated numeric criteria.

[160] *See* 40 CFR 131.41(d)(2).

Several commenters asserted that Florida would not be able to implement EPA's Federally-promulgated numeric criteria without first adopting the criteria into State law. EPA does not believe that, in order to implement EPA's Federally-promulgated numeric criteria, FDEP is required to adopt EPA's rule into State law. EPA's numeric criteria for Florida's lakes and flowing waters will be effective for CWA purposes 15 months after publication of the final criteria in the **Federal Register** and will apply in addition to any other existing CWA-effective criteria for Class I or Class III waters already adopted by the State and submitted to EPA (and for those adopted after May 30, 2000, adopted and submitted by FDEP and approved by EPA). FDEP retains the authority to move forward with its own rulemaking process at any time to establish State numeric criteria and to submit such criteria to EPA for review and approval under section 303(c) of the CWA. If FDEP does not adopt State numeric criteria, the Department retains its current authority to implement Federally promulgated criteria through the State's narrative or "free from" criteria. FDEP's General Counsel has confirmed, in a 2005 letter to EPA that the State's water quality criteria regulations for surface waters, set out at Section 62–302.500, F.A.C., provide authority for the Department to address and implement EPA promulgated criteria in CWA programs.[161]

Several commenters suggested that EPA incorporate water quality targets from adopted and approved TMDLs as site-specific criteria (SSAC) for specific waters in lieu of the more broadly applicable criteria promulgated by EPA. These commenters asserted that the TMDL values better reflect site-specific needs and were already serving as the basis for many pollutant reduction actions, including Basin Management Action Plans (BMAPs). Commenters expressed concern that actions to implement the TMDLs would be curtailed or delayed because of the uncertainty whether additional reductions might be required, and that both the Federal SSAC process (described in Section V.C of this notice) and use attainability analysis (UAA)/variance process would be too burdensome and time-consuming to be effective alternatives. Similarly, some commenters requested that specific restoration projects be exempted from EPA's criteria or that EPA employ a process for delaying application of the criteria where a water is under study.

[161] FDEP. 2005, January 5. "Petition to Withdraw Florida's NPDES Authority of March 19, 2004 Response to EPA Letter of December 8, 2004." Letter from George Munson, General Counsel.

EPA's position is that EPA-established or approved TMDLs may provide sufficient information to support a site-specific alternative criterion, but that such a demonstration should be made after considering and taking into account any new relevant information available, including but not limited to the substantial analysis and data considered and made a part of the record for this final rule. For this reason, EPA considers the Federal SSAC procedure to be the appropriate mechanism for determining whether any specific TMDL target should be adopted as a SSAC. For restoration projects or waters under study, a State-issued variance may also be an appropriate vehicle for regulatory flexibility.

Several commenters requested clarification regarding the effect of EPA's Federally-promulgated numeric criteria on existing TMDLs. A TMDL is established at levels necessary to attain and maintain "applicable narrative and numerical water quality standards." (*See* 40 CFR 130.7(c)(1)). A TMDL addressing a narrative WQS requires translating the narrative WQC into a numeric water quality target (*e.g.*, a concentration). TMDLs are not implemented directly but through other programs such as NPDES permitting and non-point source programs. For example, a NPDES permitting authority must ensure at the time of permit issuance that WQBELs are consistent with the assumptions and requirements of any available wasteload allocation (WLA) for that discharge contained in a TMDL, as well as derive from and comply with all applicable WQS. (*See* 40 CFR 122.44(d)(1)(vii)(A) and (B)).

Some existing TMDLs translate the same portion of Florida's narrative criterion, Subsection 62–302.530(47)(b), F.A.C., as EPA has translated to derive its numeric criteria, *e.g.* no imbalance in natural populations of aquatic flora and fauna. The permitting authority must ensure that any permit issuance or re-issuance include WQBELs that are as stringent as necessary to meet the promulgated numeric criteria, pursuant to CWA section 301(b)(1)(C) and 40 CFR 122.44(d)(1). These existing TMDLs will likely include information that is relevant and helpful in evaluating necessary discharge limitations, such as consideration of other sources of the pollutant and hydrodynamics of the waterbody. EPA recommends that existing TMDLs that are based on translation of Subsection 62–302.520(47)(b), F.A.C. ("no imbalance in natural population of aquatic flora and

fauna"), undergo a two-part evaluation. The first step is to assess whether the waterbody is still, in fact, water quality-limited (impaired) using the new numeric WQC. If the waterbody is still water quality-limited, then a second evaluation should be conducted to determine whether the existing TMDL based on the narrative is sufficient to meet the new numeric criterion, and in turn, whether or not it may be appropriate to revise the TMDL. The State may also wish to pursue submitting the TMDL water quality target derived by translating the narrative for determination as a Federal SSAC.

Other existing TMDLs translate another part of Florida's narrative nutrient criterion, Subsection 62–302.530(47)(a) F.A.C. This provision provides that nitrogen/phosphorus pollution shall be limited so as to prevent violation of another Florida WQS. Where a TMDL water quality target was developed as a translation of this part of Florida's narrative nutrient criterion (for example, that amount of nitrogen/phosphorus that would not cause excursions of Florida's dissolved oxygen WQS), the appropriate WQBEL is the more stringent result of applying the TMDL WLA or the promulgated numeric criteria.

It is important to keep in mind that no TMDL will be rescinded or invalidated as a result of this final rule, nor does this final rule have the effect of withdrawing any prior EPA approval of a TMDL in Florida. Neither the CWA nor EPA regulations require TMDLs to be completed or revised within any specific time period after a change in water quality standards occurs. TMDLs are typically reviewed as part of States' ongoing water quality assessment programs. Florida may review TMDLs at its discretion based on the State's priorities, resources, and most recent assessments. NPDES permits are subject to five-year permit cycles, and in certain circumstances are administratively continued beyond five years. In practice, States often prioritize their administrative workload in permits. This prioritization could be coordinated with TMDL review.

EPA-established or approved TMDLs may provide sufficient information to support a site-specific alternative criterion (SSAC). The SSAC path is one that local governments or businesses may want to pursue where they desire assurance that the TMDL will become the applicable numeric criteria in advance of the State's review of the TMDL or where substantial investments in pollution controls are predicated on water quality based effluent limits, and local governments or businesses need long-term planning certainty before making these investments. The demonstrations supporting SSAC requests for TMDLs should reflect any new relevant information that has become available since the TMDL was developed, including but not limited to the substantial analysis and data considered and made a part of the record for this final rule. For this reason, EPA considers the Federal SSAC procedure to be the appropriate mechanism for determining whether any specific TMDL target should replace the otherwise applicable numeric criteria in this final rule. EPA will work cooperatively with entities requesting SSAC to expedite consideration of TMDL targets and associated TN and/or TP levels as Federal SSAC for purposes of this final rule. As explained in the preamble to the final rule, EPA has delayed the effective date of its numeric criteria for 15 months. EPA encourages any entity wishing to have EPA adopt a particular TMDL target as a SSAC to submit such TMDL to EPA for consideration as a SSAC as soon as possible during these 15 months. When submitting such requests to EPA, such entity must copy FDEP so that FDEP may provide any comments it has to EPA. EPA would then review the SSAC application and prepare the SSAC for public notice once this final rule takes effect. Following this process, the TMDL target, if scientifically and technically justified, could replace the otherwise applicable numeric criteria within a very short period of time after this final rule takes effect. Following any such establishment of site-specific numeric criteria, the State of Florida may review and/or revise the TMDL at its discretion based on the changed criteria and the State's priorities, resources, and most recent assessments. EPA is still required to approve any changes to a previously approved TMDL.

EPA is extending the effective date of this rule, with the exception of the site-specific alternative criteria provision for reasons discussed below, for 15 months to allow time for the Agency to work with stakeholders and FDEP on important implementation issues and to help the public and all affected parties better understand the final criteria and the bases for those criteria. EPA solicited comment on the rule's proposed effective date in the preamble to the proposed rule (75 FR 4216 (January 26, 2010)) and received many comments requesting that EPA delay the effective date of the final criteria. A range of commenters suggested delayed effective dates from several months to several years, including linking the effective date of this rule with the forthcoming estuaries and coastal waters rule to allow closer coordination of the related parts of the two rulemakings. EPA does not agree with some commenters that such an extensive delay is necessary. However, EPA does believe, as discussed below, that these criteria present a unique opportunity for substantial nitrogen and phosphorus loadings reductions in the State that would be greatly facilitated and expedited by strongly coordinated and well-informed stakeholder engagement, planning, and support before a rule of this significance and broad scope begins to take effect and be implemented through the State's regulatory programs.

EPA believes that it is critical, before the rule becomes effective, to engage and support, in full partnership with FDEP, the general public, stakeholders, local governments, and sectors of the regulated community across the State in a process of public outreach, education, discussion, and constructive planning. EPA solicited comment on the proposed rule in January 2010 and has carefully considered those comments, which numbered more than 22,000, in developing the final rule. However, the nature of rule development has kept EPA from publicly discussing the contents of the final rule until the rule development process, itself, was complete. An investment in outreach, information, coordination, technical assistance and planning following this action may result in far more effective, expeditious, and ultimately effective implementation of appropriate and badly needed nutrient pollution reduction measures leading to public health and environmental improvements, the goals of this rule. EPA recognizes that in order for FDEP to effectively implement the final criteria for nutrients, it needs to plan how to best address the criteria in State programs such as the permits, waterbody assessment and listing, and TMDL programs. The State may need to develop implementation plans and guidance for affected State regulatory programs, train employees, and educate the public and regulated communities. EPA will work with FDEP as a partner over the next 15 months as FDEP takes the steps necessary to implement the new standards in an orderly manner. Moreover, EPA believes it would be useful and beneficial to have discussions with State and local officials, organizations of interested parties, and with the general public to explain the final rule, the bases for that

rule, and respond to implementation questions and concerns.

Several stakeholder groups have provided comments about particular implementation issues that will require time to address before effective implementation of the final rule can be achieved. Florida has a unique local government administration structure that includes county, municipal, and special districts, all which have overlapping authorities with respect to managing water resources. The special districts provide water resource management oversight of flood control and water supply services. These multiple layers of government authorities will require time to coordinate responsibilities. An additional concern for local governments is their budgeting process. Most local governments operate on a fiscal year cycle of October to September; thus they have recently begun a new fiscal year. These local governments engage in multi-year budget planning and have already begun laying the budget foundations for up to five successive years. EPA recognizes that Florida's agricultural community has implemented a variety of best management practices (BMPs) that are effective at reducing nitrogen and phosphorus pollution from farms. However, Florida's agriculture industry is composed of a large number of small farms (about 17,000) that have average annual sales of less than $10,000 each, and most do not receive any form of government assistance.[162] EPA anticipates that the Natural Resource Conservation Service and the University of Florida/Institute of Food and Agricultural Sciences Extension will need time to educate those not currently enrolled in nutrient management and BMP programs to control nutrient runoff.

A delayed effective date of 15 months for the criteria will also provide time for interested parties to pursue site-specific alternative criteria (SSAC) for a given waterbody. EPA's final rule and associated preamble describe the process by which any entity may seek a SSAC. A decision to seek a SSAC could not be made, however, until interested parties know what the applicable criteria would be. The Federal SSAC portion of the rule, § 131.43(e), goes into effect 60 days after publication of this rule to allow this important work to proceed in advance of the effective date for the remaining provisions of the rule. During the 15 months before the criteria become effective, parties may evaluate the final criteria, decide whether they want to seek a SSAC, and, if so, submit their SSAC application materials to EPA, copying FDEP. EPA could then review the application, and if complete, public notice the application and technical support document pursuant to the SSAC provision in the final rule. If, after reviewing public comment, EPA believes that the SSAC application meets the requirements of this rule, EPA could determine that such SSAC apply to the specific waterbody in lieu of the criteria in the final rule, even before the criteria in the final rule become effective due to the earlier effective date of the SSAC provision.

EPA believes that the 15-month period of time between publication in the **Federal Register** and the effective date of the criteria will ultimately result in attainment of the criteria in an overall shorter period of time. As EPA frequently points out in its guidance and training materials, criteria are not "self-implementing", that is, it takes knowledgeable and experienced professionals to effectively and properly employ the criteria in monitoring and assessment programs, permit limit derivation and expression, nonpoint source (NPS) control strategies, and other program applications. Without time to develop procedures, there is the risk of ineffective implementation that will not meet the underlying objective of this action—to restore and protect Florida's waters from harm caused by nitrogen and phosphorus pollution. Well designed and mapped out NPS control strategies, in particular, will be critical to gain stakeholder trust and participation.

EPA wishes to actively engage in partnership with FDEP to support FDEPs implementation of these new standards, for example by considering applications for site-specific alternative criteria. After careful consideration of time requirements for critical steps, along with recognition of important planning and accounting mechanisms such as fiscal years, and local and county meeting and planning cycles, EPA has determined that a 15-month time period is both reasonable and will allow time for important implementation activities to take place. This 15-month period will allow for a four-month education and outreach rollout to cover the major interest sectors and geographic locations throughout the State of Florida; a three-month period of training and guidance concurrent with data synthesis and analysis to support potential SSAC development; a two-month public comment and response period to allow development of effective guidance, training and possible workshops to run concurrent with SSAC submittals; a three-month period for finalizing guidance materials along with development of rollout strategies (*e.g.*, for NPS control) concurrent with notice and comment of SSAC; and finally a 3-month period for statewide education and training on guidance and contingency planning. In short, the 15 months before the criteria become effective will ensure application of programs to achieve criteria in a manner that makes the most efficient use of limited resources and gains the broadest possible support for timely and effective action upon reaching the effective date of the criteria.

IV. Under what conditions will Federal standards be withdrawn?

Under the CWA, Congress gave States primary responsibility for developing and adopting WQS for their navigable waters. (*See* CWA section 303(a)-(c)). Although EPA is promulgating numeric criteria for lakes and springs throughout Florida and flowing waters outside the South Florida Region, Florida continues to have the option to adopt and submit to EPA numeric criteria for the State's Class I and Class III waters consistent with CWA section 303(c) and implementing regulations at 40 CFR part 131.

Pursuant to 40 CFR 131.21(c), EPA's promulgated WQS are applicable WQS for purposes of the CWA until EPA withdraws those Federally-promulgated WQS. Withdrawing the Federal standards for the State of Florida would require rulemaking by EPA pursuant to the requirements of the Administrative Procedure Act (5 U.S.C.551 *et seq.*). EPA would undertake such a rulemaking to withdraw the Federal criteria if and when Florida adopts and EPA approves numeric criteria that fully meet the requirements of section 303(c) of the CWA and EPA's implementing regulations at 40 CFR part 131.

[162] NASS. 2009a. 2007 Census of agriculture Florida State and county data, Volume 1, Geographic Area Series, Part 9, AC–07–A–9, Updated December 2009, National Agricultural Statistics Service, U.S. Department of Agriculture, Washington, DC. *http://www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_State_Level/Florida/flv1.pdf* (retrieved July 15, 2010).

NASS. 2009. 2009 State agriculture overview—Florida. U.S. Department of Agriculture, National Agricultural Statistics Service, Washington, DC, *http://www.nass.usda.gov/Statistics_by_State/Ag_Overview/AgOverview_FL.pdf* (retrieved June 17, 2010).

V. Alternative Regulatory Approaches and Implementation Mechanisms

A. Designating Uses

(1) Background and Analysis

Under CWA section 303(c), States shall adopt designated uses after taking "into consideration the use and value of water for public water supplies, protection and propagation of fish, shellfish, and wildlife, recreation in and on the water, agricultural, industrial and other purposes including navigation." Designated uses "shall be such as to protect the public health or welfare, enhance the quality of water and serve the purposes of [the CWA]." (*See* CWA section 303(c)(2)(A)). EPA's regulation at 40 CFR 131.3(f) defines "designated uses" as "those uses specified in water quality standards for each waterbody or segment whether or not they are being attained." A "use" is a particular function of, or activity in, waters of the United States that requires a specific level of water quality to support it. In other words, designated uses are a State's concise statements of its management objectives and expectations for each of the individual surface waters under its jurisdiction.

In the context of designating uses, States often work with stakeholders to identify a collective goal for their waters that the State intends to strive for as it manages water quality. States may evaluate the attainability of these goals and expectations to ensure they have designated appropriate uses. (*See* 40 CFR 131.10(g)). Consistent with CWA sections 101(a)(2) and 303(c)(2)(A), EPA's implementing regulations specify that States adopt designated uses that provide water quality for the protection and propagation of fish, shellfish, and wildlife and for recreation in and on the water, wherever attainable. (*See* 40 CFR 131.10). Where States do not designate those uses, or remove those uses, they must demonstrate that such uses are not attainable consistent with the use attainability analysis (UAA) provisions of 40 CFR 131.10, specifically 131.10(g). States may determine, based on a UAA, that attaining a designated use is not feasible and propose to EPA to change the use to something that is attainable. This action to change a designated use must be completed in accordance with EPA regulations. (*See* 40 CFR 131.10(g) and (h)). In implementing these regulations, EPA allows grouping waters together in a watershed in a single UAA, provided that there is site-specific information to show how each individual water fits into the group in the context of any single UAA and how each individual water meets the applicable requirements of 40 CFR 131.10(g).

EPA's final numeric criteria for lakes and flowing waters apply to those waters designated by FDEP as Class I (Potable Water Supplies) or Class III (Recreation, Propagation and Maintenance of a Healthy, Well-Balanced Population of Fish and Wildlife). If Florida removes either the Class I and/or Class III designated use for any particular waterbody ultimately affected by this rule, and EPA finds that removal to be consistent with CWA section 303(c) and regulations at 40 CFR part 131, then the Federally-promulgated numeric criteria would not apply to that waterbody because it would no longer be designated Class I or III. Instead, any criteria associated with the newly designated use would apply to that waterbody.

(2) Summary of Major Comments

Many commenters took the opportunity to emphasize the need to adhere to the regulations governing the process of modifying or removing a designated use. Some commenters suggested that the process to change a designated use is extremely difficult. EPA's experience is that UAAs may range from simple to complex, depending on a variety of factors, such as the type of waterbody involved, the size of the segment, the use being changed, the relative degree of change proposed for the designated use, the presence of unique ecological habitats, and the level of public interest/involvement in the designated use decision. EPA agrees that, while a UAA is being conducted, the current designated use and corresponding criteria remain in place. In the case of Florida's Class I and Class III flowing waters and lakes, EPA's promulgated numeric criteria will remain the applicable WQS for CWA purposes, including assessments, listings, TMDL development and the issuance of NPDES permits, unless and until the State adopts revised designated uses (with different associated criteria) that are submitted to and approved by EPA under CWA section 303(c).

B. Variances

(1) Final Rule

For purposes of this rule, EPA is promulgating criteria that apply to use designations that Florida has already established. EPA believes that the State has sufficient authority to use its currently EPA-approved variance procedures with respect to a temporary modification of its Class I or Class III uses as it pertains to any Federally-promulgated criteria. For this reason, EPA did not propose and is not promulgating an alternative Federal variance procedure.

(2) Background and Analysis

A variance is a temporary modification to the designated use and associated water quality criteria that would otherwise apply to the receiving water.[163] Variances constitute new or revised WQS subject to the substantive requirements applicable to removing a designated use.[164] Thus, a variance is based on the same factors, set out at 40 CFR 131.10(g), that are required to revise a designated use through a UAA. Typically, variances are time-limited (*e.g.*, three to five years), but renewable. Temporarily modifying the designated use for a particular waterbody through a variance process allows a State to limit the applicability of a specific criterion to that water and to identify an alternative designated use and associated criteria to be met during the term of the variance. A variance should be used instead of removal of a use where the State believes the standard can be attained at some point in the future. By maintaining the designated use for all other criteria and dischargers, and by specifying a point in the future when the designated use will be fully applicable in all respects, the State ensures that further progress will be made in improving water quality and attaining the standard. A variance may be written to address a specified geographic area, a specified pollutant or pollutants, and/or a specified pollutant source. All other applicable WQS not specifically modified by the variance would remain applicable (*e.g.*, any other criteria adopted to protect the designated use). State variance procedures, as part of State WQS, must be consistent with the substantive requirements of 40 CFR part 131. Each variance, as a revised WQS, must be submitted to EPA for review pursuant to CWA section 303(c). A variance allows, among other things, NPDES permits to be written such that reasonable progress is made[165] toward attaining the underlying standards for affected waters without violating section 402(a)(1) of the Act, which requires that NPDES permits

[163] Water Quality Standards Regulation, 40 CFR part 131: Advance notice of proposed rulemaking. USEPA FR 63:129 (July 7, 1998). p. 36741–36806.

[164] *In re Bethlehem Steel Corporation*, General Counsel Opinion No. 58. March 29, 1977 (1977 WL 26245 (E.P.A. G.C.)).

[165] USEPA. 1994. *Water Quality Standards Handbook: Second Edition*. EPA–823–B–94–005a. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

must meet the applicable WQS. (*See* CWA section 301(b)(1)(C)).

(3) Summary of Major Comments

In response to comments, EPA agrees that variances could be adopted on a multiple-discharger basis and can be renewed so long as the State and EPA conclude that such variances are consistent with the CWA and implementing regulations. In this regard, EPA allows grouping waters together in a watershed in a single variance application, provided that there is site-specific information to show how each individual water fits into the group in the context of any single variance and how each individual water meets the applicable requirements of 40 CFR 131.10(g). EPA disagrees that Florida law, at 403.201(2), F.S., prohibits the State from issuing variances for waters affected by the Federally-promulgated numeric criteria. Florida law at 403.201(2), F.S., provides that a variance may not be granted that would result in State requirements that are less stringent than a comparable Federal provision or requirement. As discussed above, a variance is a temporary modification to the designated use and thus to the associated water quality criteria that would otherwise apply to the receiving water. EPA's Federal rule, however, does not promulgate or revise any Florida designated uses. EPA's criteria are intended to protect the Class I and Class III designated uses that Florida already has in place. EPA's criteria do not apply where and when the use is something other than Class I or Class III, as would be the case for a variance. Rather, Florida would establish alternative criteria associated with the variance. Any variance would constitute a new or revised WQS subject to EPA review and approval pursuant to section 303(c) of the CWA.

C. Site-Specific Alternative Criteria

(1) Final Rule

EPA believes that there is benefit in establishing a specific procedure in the Federal rule for EPA adoption of Federal site-specific alternative criteria (SSAC) for the numeric chlorophyll *a*, TN, TP, and nitrate+nitrite criteria in this rule. In this rulemaking, EPA is promulgating a procedure whereby the Regional Administrator, Region 4, may establish a SSAC after providing for public comment on the proposed SSAC and the supporting documentation. (*See* 40 CFR 131.43(e)). This procedure allows any entity, including the State, to submit a proposed Federal SSAC directly to EPA for the Agency's review and assessment as to whether an adjustment to the applicable Federal numeric criteria is appropriate and warranted. The Federal SSAC process is separate and distinct from the State's SSAC processes in its WQS.

The Federal SSAC procedure allows EPA to determine that a revised site-specific chlorophyll *a*, TN, TP, or nitrate + nitrite numeric criterion should apply in lieu of the generally applicable criteria promulgated in this final rule where that SSAC is demonstrated to be protective of the applicable designated use(s). The promulgated procedure provides that EPA will solicit public comment on its determination. Because EPA's rule establishes this procedure, implementation of this procedure does not require withdrawal of Federally-promulgated criteria for affected water bodies for the Federal SSAC to be effective for purposes of the CWA. EPA has promulgated similar procedures for EPA granting of variances and SSACs in other Federally-promulgated WQS.[166]

EPA is aware of concerns expressed by some commenters that a waterbody may exceed the numeric criteria in this rule and still meet Florida's designated uses related to recreation, public health, and the propagation and maintenance of a healthy, well-balanced population of fish and wildlife. EPA recognizes that there may be certain situations where additional, new, or more specific data related to the local conditions or biology of a particular waterbody may well support an alternate site-specific numeric criteria which may appropriately be more (or less) stringent than the criteria in this final rule in order to ensure maintenance of instream designated uses and protection of downstream waters. EPA believes that the SSAC process is an appropriate mechanism to address such situations and is committed to acting on Federal SSAC applications intended to address such situations as expeditiously as possible.

The process for obtaining a Federal SSAC includes the following steps. First, an entity seeking a SSAC compiles the supporting data, conducts the analyses, develops the expression of the criterion, and prepares the supporting documentation demonstrating that alternative numeric criteria are protective of the applicable designated use. The "entity" may be the State, a city or county, a municipal or industrial discharger, a consulting firm acting on a behalf of a client, or any other individual or organization. The entity requesting the SSAC bears the burden of demonstrating that any proposed SSAC meets the requirements of the CWA and EPA's implementing regulations, specifically 40 CFR 131.11. Second, if the entity is not the State, the entity must provide notice of the proposed SSAC to the State, including all supporting documentation so that the State may provide comments on the proposal to EPA. Third, the Regional Administrator will evaluate the technical basis and protectiveness of the proposed SSAC and decide whether to publish a public notice and take comment on the proposed SSAC. The Regional Administrator may decide not to publish a public notice and instead return the proposal to the entity submitting the proposal, with an explanation as to why the proposed SSAC application did not provide sufficient information for EPA to determine whether it meets CWA requirements or not. If EPA solicits public comment on a proposed SSAC, upon review of comments, the Regional Administrator may determine that the Federal SSAC is appropriate to account for site-specific conditions and make that determination publicly available together with an explanation of the basis for the decision. The Regional Administrator may also determine that the Federal SSAC is not appropriate and make that determination publicly available together with an explanation of the basis for the decision.

To successfully develop a Federal SSAC for a given lake, stream, or spring, a thorough analysis is necessary that indicates how designated uses are being supported both in the waterbody itself and in downstream water bodies at concentrations of either TN, TP, chlorophyll *a*, or nitrate+nitrite that are either higher or lower than the Federally-promulgated applicable criteria. This analysis should have supporting documentation that consists of examining both indicators of longer-term response to multiple stressors, such as benthic macroinvertebrate health as determined by Florida's Stream Condition Index (SCI), and indicators of shorter-term response specific to nitrogen/phosphorus pollution, such as periphyton algal thickness or water column chlorophyll *a* concentrations. To pursue a Federal SSAC on a watershed-wide basis, the same types of procedures that EPA used to develop the Federally promulgated applicable criteria can be used with further refinements to the categorization of water bodies. For example, an entity could derive alternative instream protective TP and/or TN values using

[166] *See* 40 CFR 131.33(a)(3), 40 CFR 131.34(c), 40 CFR 131.36(c)(3)(iii), 40 CFR 131.38(c)(2)(v), 40 CFR 131.40(c).

EPA's approach by further sub-delineating the Nutrient Watershed Regions and providing the corresponding data, analysis and documentation to support derivation of an alternative criteria that is protective of the designated use that applies both to the smaller watershed regions as well as to downstream waters. This type of refined reference condition approach is described in EPA guidance manuals[167] and would be consistent with methods used to develop the Federally-promulgated criteria for Florida. In developing either a site-specific or watershed-wide Federal SSAC, it is necessary to ensure that values allowed in an upstream segment as a result of a SSAC provide for the attainment and maintenance of the WQS of downstream waters. It will be important to examine a stream system on a broader basis to ensure that a SSAC established for one segment does not result in adverse effects in nearby segments or downstream waters, such as a downstream lake.

This rule specifically identifies four approaches for developing SSAC. The first two approaches are replicating the approaches EPA used to develop stream and lake criteria, respectively, and applying these methods to a smaller subset of waters. The third approach for developing SSAC is to conduct a biological, chemical, and physical assessment of waterbody conditions. The fourth approach for developing SSAC is a general provision for using another scientifically defensible approach that is protective of the designated use. The first two approaches for developing SSAC replicate EPA's methods in deriving the stream and lake criteria set out in this final rule. To understand the necessary steps in this analysis, interested parties should refer to the complete documentation of these methods in the materials included in the rule docket.

The third approach for developing SSAC is to conduct a biological, chemical, and physical assessment of waterbody conditions. This is a more general approach than the replication approaches and would need additional detail and description of supporting rationale in the documentation submitted to EPA. The components of this approach could include, but not be limited to, evaluation of benthic macroinvertebrate health using the Stream Condition Index (SCI), presence or absence of native flora and fauna, chlorophyll *a* concentrations or periphyton density, average daily dissolved oxygen fluctuation, organic versus inorganic components of total nitrogen, habitat assessment, and hydrologic disturbance. This approach could apply to any waterbody type, with specific components of analysis tailored for the situation. The fourth approach for developing SSAC is a general provision for using another scientifically defensible approach that is protective of the designated use. This provision allows applicants to make a complete demonstration to EPA using methods not otherwise described in the rule or its statement of basis, consistent with 40 CFR 131.11(b)(1)(iii). This approach could potentially include use of mechanistic models or other data and information.

(2) Background and Analysis

A SSAC is an alternative value to criteria set forth in this final rule that would be applied on a watershed, area-wide, or water-body specific basis that meets the regulatory test of protecting the instream designated use, having a basis in sound science, and ensuring the protection and maintenance of downstream WQS. SSAC may be more or less stringent than the otherwise applicable Federal numeric criteria. In either case, because the SSAC must protect the same designated use and must be based on sound science (*i.e.*, meet the requirements of 40 CFR 131.11(a)), there is no need to modify the designated use or conduct a UAA. A SSAC may be appropriate when further scientific data and analyses can bring added precision or accuracy to express the necessary level or concentration of chlorophyll *a*, TN, TP, and/or nitrate+nitrite that protects the designated use for a particular waterbody.

(3) Summary of Major Comments

Many commenters expressed support for the concept of EPA's proposed SSAC procedure, although many also expressed concerns about the viability, requirements, expense, and time associated with the process. In EPA's proposed rule, the SSAC process was to be initiated by the State submitting a request to EPA. Many commenters were confused about the relationship between the Federal SSAC process and the State's Type 1 and Type 2 SSAC processes, and how the processes relate for purposes of the Federal rule. The Federal SSAC process is separate and independent from the State SSAC processes. A Federal SSAC is established by the Regional Administrator of EPA Region 4 after due notice and comment from the public. To resolve this confusion, and to provide a more direct means for entities other than the State to initiate the SSAC process, EPA's final rule provides that any entity may submit a request for a SSAC directly to the Regional Administrator. The final rule adds a requirement that entities submit proposed SSAC and supporting materials to the State at the same time those materials are submitted to EPA to ensure the State has the opportunity to submit comments to EPA.

As several commenters have pointed out, Florida WQS regulations currently do not authorize the State to adopt a SSAC as State WQS except where natural conditions are outside the limits of broadly applicable criteria established by the State (Section 62-302.800, F.A.C.). However, the State may choose to be the entity that submits a SSAC request to EPA under the Federal process described above and set forth at 40 CFR 131.43(e). There is no requirement that the State go through its own State-level Type 1 or Type 2 SSAC process before submitting a proposed SSAC to EPA for consideration under this rule.

Commenters included suggestions for specific approaches for developing SSAC as well as an "expedited" process for determination as a Federal SSAC. EPA agrees that many of the suggested approaches have merit for purposes of developing SSAC, and has adapted many of the suggestions to provide more information on approaches that would meet the general requirements for protective criteria. Many of the comments regarding an "expedited" process suggested a process where SSAC become effective automatically, without need for EPA review and approval. With the exception of State adjustment of lake criteria within a very specific and limited range accompanied by a specified data set and calculation as discussed in Section III.C(2)(e) above, the Agency does not agree with the view that criteria established in this rule can be revised without documentation and public notice and comment process as outlined above.[168] Another commenter asked about the potential to develop a SSAC on a "watershed-scale." EPA does not see any barrier to conducting such an analysis, where it can be demonstrated that the watershed-scale SSAC is protective for all waters in a particular grouping and meets the requirements of 40 CFR 131.11 and 40

[167] USEPA. 2000b. *Nutrient Criteria Technical Guidance Manual: Rivers and Streams.* EPA-822-B-00-002. U.S. Environmental Protection Agency, Office of Water, Washington, DC.

[168] EPA's criteria allow for one-time site-specific modifications to the promulgated lake criteria, without requiring those modifications to be submitted as SSAC. *See* 40 CFR 131.43(c)(1)(ii) and Section III.C(2)(e).

CFR 131.10(b). Many commenters expressed the desire to defer the applicability of promulgated criteria prior to developing a SSAC. The Federal SSAC portion of the rule, § 131.43(e), goes into effect 60 days after publication of this rule to allow this important work to proceed in advance of the effective date of 15 months after publication for the remaining provisions of the rule. The SSAC review process will depend in substantial part on the nature of the SSAC proposal itself: Its clarity, substance, documentation, and scientific rigor. Some commenters stated that EPA's requirement that Federal SSAC be scientifically defensible and protective of designated uses is too vague; however, it is the same requirement for criteria in the Federal WQS regulation. (*See* 40 CFR 131.11). EPA will consider the need for further developing supporting technical guidance in the future if it appears at that time that such guidance would help support the process.

D. Compliance Schedules

(1) Final Rule

Florida has adopted a regulation authorizing compliance schedules. That regulation, Subsection 62–620.620(6), F.A.C., is not affected by this final rule. The complete text of the Florida rules concerning compliance schedules is available at *https://www.flrules.org/gateway/RuleNo.asp?ID=62–620.620*. Florida is, therefore, authorized to grant compliance schedules, as appropriate, under its rule for WQBELs based on EPA's numeric criteria.

(2) Background and Analysis

A compliance schedule, or schedule of compliance, refers to "a schedule of remedial measures included in a 'permit,' including an enforceable sequence of interim requirements * * * leading to compliance with the CWA and regulations." (*See* 40 CFR 122.2, CWA section 502(17)). In an NPDES permit, WQBELs are effluent limits based on applicable WQS for a given pollutant in a specific receiving water (*See* NPDES Permit Writers Manual, EPA–833–B–96–003, December, 1996). EPA regulations provide that schedules of compliance may only be included in permits if they are determined to be "appropriate" given the circumstances of the discharge and are to require compliance "as soon as possible" (*See* 40 CFR 122.47).[169]

[169] Hanlon, Jim, USEPA Office of Wastewater Management. 2007, May 10. Memorandum to Alexis Strauss, Director of Water Division EPA Region 9, on "Compliance Schedules for Water Quality-Based Effluent Limitations on NPDES Permits."

(3) Summary of Major Comments

EPA generally received favorable comment on its description of compliance schedules. Some commenters asked EPA to consider promulgating its own compliance schedule provisions as part of the final rule. Florida's regulations, however, already include an authorizing provision that allows NPDES permit writers to include compliance schedules in permits, where appropriate. Florida's regulations do not limit the criteria which may be subject to compliance schedules. Therefore, Florida may choose to issue permit compliance schedules for nitrogen/phosphorus pollution, as appropriate. As a result, there is no need for EPA to provide an additional compliance schedule authorizing provision in this final rule. EPA disagrees with commenters who assert that Florida's regulation at Subsection 62–620.620(6), F.A.C., authorizing compliance schedules applies only to industrial and domestic wastewater facilities. Chapter 62–620, F.A.C., sets out permit procedures for wastewater facilities or activities that discharge wastes into waters of the State or which will reasonably be expected to be a source of water pollution. (*See* Subsection 62–620.100(1), F.A.C.). Subsection 62–620.620(6), F.A.C., applies, therefore, more broadly than to just industrial and domestic wastewater facilities. In addition, Chapter 62–4, F.A.C., which sets out procedures on how to obtain a permit from FDEP, provides that permits may include a reasonable time for compliance with new or revised WQS. Subsection 62–4.160(10), F.A.C., does not limit the type of permits that may include such compliance schedules.

E. Proposed Restoration Water Quality Standard

(1) Final Rule

In EPA's January 2010 proposal, the Agency proposed a new WQS regulatory tool for Florida, referred to as "restoration WQS" for impaired waters. This provision was intended to allow Florida to retain full aquatic life protection (uses and criteria) for its water bodies while establishing a transparent phased WQS process that would result in implementation of enforceable measures and requirements to improve water quality over a specified time period to ultimately meet the long-term designated aquatic life use. For reasons discussed below and in EPA's response to comment document, EPA has decided not to promulgate a restoration WQS tool specifically for Florida, as proposed.

(2) Summary of Major Comments

EPA received a significant number of comments on its proposal that provided constructive and useful information for EPA to consider regarding the proposed restoration WQS provision. Such comments ranged from identifying additional needed requirements to concerns that the restoration WQS tool was so burdensome it would not be helpful. EPA evaluated the current, existing flexibility available to Florida to implement this final rule through variances, compliance schedules, permit reissuance cycles, permit reopener provisions, TMDL scheduling, and workload and administrative prioritization. These are all considerations that FDEP presently brings to the administration of its water quality program. EPA also considered the flexibility that this final rule offers through lake criteria adjustment provisions, alternative approaches to deriving downstream lake protection values and the SSAC process discussed above. The Agency concluded that the range of implementation tools available to the State in combination with a number of the provisions contained in this final rule provide adequate flexibility to implement EPA's numeric criteria finalized in this rule. Florida may use any of these existing tools or exercise its authority to propose additional tools in the future that allow implementation flexibility where demonstrated to be appropriate and consistent with the CWA and implementing regulations. Therefore, EPA believes that its decision not to finalize restoration WQS will not adversely affect Florida's ability to implement the Federal numeric criteria.

VI. Economic Analysis

State implementation of this rule may result in new or revised National Pollutant Discharge Elimination System (NPDES) permit conditions for point source dischargers, and requirements for nitrogen/phosphorus pollution treatment controls on other sources (*e.g.*, agriculture, urban runoff, and/or septic systems) through the development of additional Total Maximum Daily Loads (TMDLs) and Basin Management Action Plans (BMAPs). To provide information on the potential incremental costs associated with these related State actions, EPA conducted an analysis to estimate both the additional impaired waters that may be identified as a result of this final rule and the potential State of Florida requirements that may be

necessary to assure attainment of applicable State water quality designated uses. EPA's analysis is fully described in the document entitled: "*Economic Analysis of Final Water Quality Standards for Nutrients for Lakes and Flowing Waters in Florida,*" which can be found in the docket and record for this final rule.

An economic analysis of a regulation compares a likely scenario absent the regulation (the baseline) to a likely scenario with the regulation. The impacts of the regulation are measured by the resulting differences between these two scenarios (incremental impacts). However, the regulatory effect of this final rule can be interpreted in several ways, which can significantly influence the conditions considered appropriate for representing the baseline. On January 14, 2009 EPA made a determination that numeric nutrient water quality criteria were necessary to meet the requirements of the CWA in the State of Florida. In July 2009 the State of Florida released draft numeric nutrient criteria for lakes and streams.[170] Therefore, when the Agency proposed this rule for lakes and flowing waters in January 2010, EPA evaluated the incremental impacts of the proposed rule in comparison with the provisions of the Florida July 2009 draft criteria. Although the State subsequently did not proceed forward with those numeric criteria provisions, EPA has conducted the same evaluation as part of the economic analysis accompanying this final rule to illustrate the difference between Florida's draft approach and the provisions of this rule. Using this same baseline approach and the refined analysis methodology described below, EPA estimates the potential incremental costs associated with this rule as ranging between $16.4 million/year and $25.3 million/year.

An alternative interpretation of the impact of this final rule is that EPA is promulgating numeric criteria to address deficiencies in the State of Florida's current narrative nutrient criteria (current conditions approach), and the incremental impacts of this rule are those associated with the difference between EPA's numeric criteria and Florida's narrative criteria. Under this scenario, the baseline incorporates requirements associated with current water quality, impaired waters, and TMDLs that exist at the time of the analysis. The incremental impacts of this rule are the costs and benefits associated with additional pollution controls beyond those currently in place or required as a result of Florida's existing narrative criteria. This analysis is principally designed to gain an understanding of the potential costs and benefits associated with implementation of EPA's numeric criteria for lakes and flowing waters above and beyond the costs associated with State implementation of its current narrative nutrient criteria for those waters. For waters that the State of Florida has already identified as impaired, EPA expects that the effect of this final rule will be to shorten the time and reduce the resources necessary for the State of Florida to implement its existing regulatory and nonregulatory framework of tools, limits, measures and BMP guidance to initiate a broader, expedited, more comprehensive, and more effective approach to reducing nutrient loadings necessary to meet the numeric criteria that support current State designated uses. The further effect of this final rule will likely be the assessment and identification of additional waters that are impaired and not meeting the designated use set forth at Section I.B, and new or revised water quality-based effluent limits in NPDES permits. EPA's economic analysis quantifies the costs and cost savings associated with the identification of newly impaired waters and new or revised water quality-based effluent limits, but does not attempt to measure the costs and cost savings associated with addressing waters that are currently listed as impaired under Florida's existing narrative nutrient criteria (these costs are considered part of the baseline).

Although using the State of Florida's draft numeric criteria as a baseline provides one possible measure of the incremental impact associated with this final rule, the current conditions approach can provide valuable information to the State of Florida and the public about other potential costs and benefits that may be realized as a result of this final rule. To provide this additional information, and in part to respond to public comments on the economic analysis at proposal, this economic analysis also measures the incremental costs and benefits of this final rule using current conditions in the State of Florida as the baseline. Using this interpretation of the baseline, EPA estimates the potential incremental costs associated with this final rule as ranging between $135.5 million per year and $206.1 million per year. Although analyses using both baselines are described in EPA's economic analysis document entitled: "*Economic Analysis of Final Water Quality Standards for Nutrients for Lakes and Flowing Waters in Florida,*" the analytical methods and results described below highlight the current conditions baseline in detail.

To develop this analysis, EPA first assessed State control requirements associated with current water quality, impaired waters, and total maximum daily loads (the baseline). EPA then assessed the costs and benefits associated with additional pollution controls beyond those currently in place or required to meet EPA's numeric criteria that support Florida designated uses. To estimate incremental point source costs, EPA gathered publicly available information and data on control technologies currently in place at wastewater treatment plants and other industrial facilities, and used Florida Department of Environmental Protection (FDEP) point source implementation procedures to project the potential additional treatment that the State may require as a result of applying the criteria in this final rule. EPA assessed potential non-point source control costs by using publicly available information and data to determine land uses near waters that would likely be identified as impaired under this rule, and using FDEP and the Florida Department of Agriculture and Consumer Services (FDACS) nonpoint source control procedures, estimated costs to implement agricultural best management practices (BMPs) the State may require in order to attain the new numeric criteria. EPA also estimated the potential costs of additional State control requirements for storm water runoff, and potential costs associated with upgrades of homeowner septic systems. EPA also assessed additional potential government regulatory costs of developing additional total maximum daily loads (TMDLs) for waters identified as impaired under this rule. Finally, EPA qualitatively and quantitatively described and estimated some of the potential benefits of complying with the new water quality standards. Because of the inherent uncertainties associated with the benefits analysis, potential benefits are likely underestimated compared to costs. Although it is difficult to predict with certainty how the State of Florida will implement these new water quality standards, the results of these analyses represent EPA's estimates of costs and benefits of this final rule.

A. Point Source Costs

Point sources of wastewater must have a National Pollution Discharge

[170] Florida Department of Environmental Protection, 2009, "Draft Technical Support Document: Development of Numeric Nutrient Criteria for Florida Lakes and Streams," available electronically at: *http://www.dep.state.fl.us/water/wqssp/nutrients/docs/tsd_nutrient_crit.docx.*

Elimination System (NPDES) permit to discharge into surface waters. EPA identified point sources potentially discharging nitrogen or phosphorus to lakes and flowing waters by evaluating EPA's NPDES Permit Compliance System (PCS) database. EPA identified all the industry codes associated with any permitted discharger with an existing numeric effluent limit or monitoring requirement for nitrogen or phosphorus. This analysis identified 193 point sources as having the potential to discharge nitrogen and/or phosphorus. The following table summarizes the number of point sources with the potential to discharge nitrogen and/or phosphorus.

TABLE VI(A)—POINT-SOURCES POTENTIALLY DISCHARGING NITROGEN AND/OR PHOSPHORUS TO FLORIDA LAKES AND FLOWING WATERS

Discharger category	Major dischargers [a]	Minor dischargers [b]	Total
Municipal Wastewater	43	42	85
Industrial Wastewater	57	51	108
Total	100	93	193

[a] Facilities discharging greater than one million gallons per day and likely to discharge toxic pollutants in toxic amounts.
[b] Facilities discharging less than one million gallons per day and not likely to discharge toxic pollutants in toxic amounts.

1. Municipal Waste Water Treatment Plant (WWTP) Costs

EPA considered the costs of known nitrogen and phosphorus treatment options for municipal WWTPs. Nitrogen and phosphorus removal technologies that are available can reliably attain an annual average total nitrogen (TN) concentration of approximately 3.0 mg/L or less and an annual average total phosphorus (TP) concentration of approximately 0.1 mg/L or less.[171] Wastewater treatment to these concentrations was considered target levels for the purpose of this analysis.

The NPDES permitting authority determines the need for water quality based effluent limits for point sources on the basis of analysis of reasonable potential to exceed water quality criteria. To estimate the potential incremental costs for WWTPs, the likelihood that WWTPs discharging to Florida lakes and flowing waters have reasonable potential to exceed the numeric criteria in this final rule should be evaluated. However, the site-specific data and information required to precisely determine reasonable potential for each facility was not available. Thus, on the basis that most WWTPs are likely to discharge nitrogen and phosphorus at concentrations above applicable criteria, EPA made the conservative assumption that all WWTPs have reasonable potential to exceed the numeric criteria.

For municipal wastewater, EPA estimated costs to reduce effluent concentrations to 3 mg/L or less for TN and 0.1 mg/L or less for TP using advanced biological nutrient removal (BNR). Although reverse osmosis and other treatment technologies may have the potential to reduce nitrogen and phosphorus concentrations even further, EPA believes that implementation of reverse osmosis applied on such a large scale has not been demonstrated as practical or necessary.[172] Such treatment has not been required for WWTPs by the State of Florida in the past, even those WWTPs under TMDLs with nutrient targets comparable to the criteria in this final rule. EPA believes that should state-of-the-art BNR technology together with other readily available physical and chemical treatment demonstrated to be effective in municipal WWTP operations not result in compliance with permit limits associated with meeting the new numeric nutrient criteria, then it is reasonable to assume that entities would first seek out other available means of attaining water quality standards such as reuse, nonpoint source reductions, site-specific alternative criteria, variances, and designated use modifications.

To estimate compliance costs for WWTPs, EPA identified current WWTP treatment performance using information obtained from NPDES permits and/or water quality monitoring reports. EPA assumed that WWTPs under existing TMDLs are currently meeting their wasteload allocation requirements and would not incur additional treatment costs. EPA further assumed that costs to WWTPs discharging to currently impaired waters are not attributable to this final rule because those costs would be incurred absent the rule (under the baseline). However, sufficient location information was not available to insure that all WWTPs discharging to impaired waters were identified. Thus, costs may be overstated to the extent that some WWTPs discharging to currently impaired waters are included in EPA's estimate. The following table summarizes EPA's best estimate of the number of potentially affected municipal WWTPs that may require additional treatment to meet the numeric criteria supporting State designated uses.

TABLE VI(A)(1)(a)—POTENTIAL ADDITIONAL NUTRIENT CONTROLS FOR MUNICIPAL WASTEWATER TREATMENT PLANTS

Discharge type	Number of dischargers				
	Additional reduction in TN and TP [a]	Additional reduction in TN only [b]	Additional reduction in TP only [c]	No incremental controls needed [d]	Total
Major	11	2	9	21	43
Minor	19	1	3	19	42

[171] U.S. EPA, 2008, "Municipal Nutrient Removal Technologies Reference Document. Volume 1—Technical Report," EPA 832–R–08–006.

[172] Treatment using reverse osmosis also requires substantial amounts of energy and creates disposal issues as a result of the large volume of concentrate that is generated.

TABLE VI(A)(1)(a)—POTENTIAL ADDITIONAL NUTRIENT CONTROLS FOR MUNICIPAL WASTEWATER TREATMENT PLANTS—Continued

Discharge type	Number of dischargers				
	Additional reduction in TN and TP [a]	Additional reduction in TN only [b]	Additional reduction in TP only [c]	No incremental controls needed [d]	Total
Total	30	3	12	40	85

[a] Includes dischargers without treatment processes capable of achieving the target levels or existing WLA for TN and TP, or for which the treatment train description is missing or unclear.
[b] Includes dischargers with chemical precipitation only and those with a wasteload allocations under a TMDL for TP only.
[c] Includes dischargers with MLE, four-stage Bardenpho, and BNR specified to achieve less than 3 mg/L and those with WLA under a TMDL for TN only.
[d] Includes dischargers with A^2/O, modified Bardenpho, modified UCT, oxidation ditches, or other BNR coupled with chemical precipitation and those with WLAs under a TMDL for both TN and TP.

An EPA study provides unit cost estimates for biological nutrient removal controls for various TN and TP performance levels.[173] To estimate costs for WWTPs, EPA used the average capital and average operation and maintenance (O&M) unit costs for technologies that achieve an annual average of 3 mg/L or less for TN and/or 0.1 mg/L or less for TP. EPA also estimated a maximum cost for TN and TP reduction by using the highest cost TN and TP removal technology (estimated by finding the maximum of annualized costs for each technology option). Using average and maximum unit costs and multiplying unit costs by flow reported in EPA's PCS database, EPA estimated total capital costs could be approximately $108 million to $219 million and operation and maintenance (O&M) costs could be approximately $12 million per year to $18 million per year. Total annual costs would be approximately $22.3 million per year to $38.1 million per year (capital costs annualized at 7% over 20 years). The following table summarizes estimated costs for municipal WWTPs.

TABLE VI(A)(1)(b)—POTENTIAL INCREMENTAL COSTS FOR MUNICIPAL WASTE WATER TREATMENT PLANTS

Cost component	Capital costs (millions) [a]	O&M costs (millions per year)	Annual costs (millions per year)
Advanced BNR	$108–$219	$12–$18	$22.3–$38.1

[a] Low estimate represents average of unit costs; high estimate represents costs for treatment processes that results in the highest annualized costs (annualized capital at 7% over 20 years plus O&M).

Using Florida's 2009 draft criteria as the baseline, municipal WWTP costs associated with this final rule are zero because treatment technologies needed to achieve Florida's 2009 draft criteria are the same as those needed to achieve the criteria in this final rule, even though the criteria themselves are somewhat different.

After EPA published its proposed criteria for Florida (75 FR 4173), several organizations in Florida developed alternative estimates of compliance costs for WWTPs that were substantially higher than EPA's estimated costs. EPA disagrees with these cost estimates because they included costs for nutrient controls that are beyond what would be required by Florida to meet the new numeric criteria. For example, the Florida Water Environment Association Utility Council (FWEAUC) estimated annual costs for WWTPs would be approximately $2.0 billion per year to $4.4 billion per year.[174] However, FWEAUC included in their analysis facilities that discharge to estuaries or coastal waters, and facilities that utilize deep well injection or generate reuse water which are not covered by this rule. FWEAUC also estimated costs to upgrade WWTPs regardless of the treatment that already exists at the facilities. Finally, FWEAUC assumed that all WWTPs will require expensive microfiltration and reverse osmosis control technology to comply with the new standard. EPA is not aware of any WWTPs in Florida that utilize microfiltration or reverse osmosis, even those discharging to currently impaired waters with TMDLs that have nutrient targets comparable to the criteria in this final rule. Thus, as noted above, EPA does not believe that this type of treatment technology for WWTPs in Florida has been demonstrated as practical or necessary. These differences appear to explain the discrepancy between FWEAUC and EPA estimates.

2. Industrial Point Source Costs

Incremental costs for industrial dischargers are likely to be facility-specific and depend on process operations, existing treatment trains, and composition of waste streams. EPA previously estimated that 108 industrial dischargers may potentially be affected by this rule (Table VI(A)). Of those 108 dischargers, EPA identified 38 of them as under an existing TMDL for nitrogen and/or phosphorus and 14 of them as discharging to waters listed as impaired for nutrients and/or dissolved oxygen. As with WWTPs, EPA assumed that industrial dischargers under an existing TMDL are currently meeting their wasteload allocation requirements and would not incur additional treatment costs, and costs at facilities discharging to currently impaired waters are not attributable to this final rule because those costs would be incurred absent the rule (under the baseline). To estimate the potential costs to the remaining 56 potentially affected

[173] U.S. EPA, 2008.

[174] Florida Water Environment Association Utility Council, 2009, "Numeric Nutrient Criteria Cost Implications for Florida POTWs," available electronically at: *http://www.fweauc.org/PDFs/FWEAUC%20letter%20to%20Crist%20re%20NNC%20Cost%20Implications%20for%20Fla%20POTWs%20with%20attachment.pdf.*

industrial facilities, EPA took a random sample of those facilities from each industry. EPA then analyzed their effluent data obtained from EPA's PCS database and other information in NPDES permits to determine whether or not they have reasonable potential to cause or contribute to an exceedance of the numeric nutrient criteria in this final rule. For those facilities with reasonable potential, EPA further analyzed their effluent data and estimated potential revised water quality based effluent limits (WQBEL) for TN and TP. If the data indicated that the facility would not be in compliance with the revised WQBEL, EPA estimated the additional nutrient controls those facilities would likely implement to allow receiving waters to meet State designated uses and the costs of those controls. EPA then calculated the average flow-based cost of compliance for the sampled facilities in each industrial category, and used the average cost to extrapolate to the potential cost for the total flow associated with all facilities in each category (*see* economic analysis support document for more information). Using this method, EPA estimated the potential costs for industrial dischargers could be approximately $25.4 million per year.

TABLE VI(A)(2)—POTENTIAL INCREMENTAL COSTS FOR INDUSTRIAL DISCHARGERS

Industrial category	Total number of facilities	Number of facilities sampled	Average sample cost ($/mgd/yr) [a]		Total annual costs [b]
Chemicals and Allied Products	9	2	$14,100	$1,116,800	
Electric Services	9	2	0		$0
Food	7	2	123,300		1,390,000
Mining	10	2	160,600	16,442,300	
Other	17	3	0	0	
Pulp and Paper	4	1	117,300	6,466,800	
Total	56	12		25,415,900	

[a] Calculated by dividing total annual sample discharger costs by total sample discharger flow. Note that where flow for a sample discharger is not available, EPA used the average flow for dischargers in that category and discharger type (major or minor).
[b] Represents average sample discharger unit cost multiplied by total flow of dischargers affected by the rule in each industrial category.

Using Florida's 2009 draft criteria as the baseline, industrial discharger costs associated with this final rule is zero because treatment technologies needed to achieve the Florida's 2009 draft criteria are the same as those needed to achieve the criteria in this final rule, even though the criteria themselves are somewhat different.

Several organizations in Florida developed alternative estimates of compliance costs for EPA's proposed rule that were substantially higher than EPA's estimated costs for industrial dischargers. EPA disagrees with these cost estimates because they assumed that facilities will need to install treatment technologies that are much more expensive than those that would likely be required by Florida to meet the numeric criteria. For example, FDEP estimated that the costs for industrial dischargers would be approximately $2.1 billion per year.[175] However, FDEP assumed that every industrial facility would treat their total discharge volume using reverse osmosis which EPA believes is impractical and unnecessary. In addition, FDEP estimated costs for reverse osmosis on the basis of each facility's maximum daily discharge flow instead of its reported design capacity (in some cases the maximum daily flow was more than double the design capacity). Installing treatment technology to handle maximum daily flows would be unnecessary because equalization basins or storage tanks (used to temporarily hold effluent during peak flows) would be a less expensive compliance strategy. Finally, EPA found no indication that industrial facilities in Florida have installed reverse osmosis for the purpose of complying with a nutrient-related TMDL, even those TMDLs with nutrient targets comparable to the criteria in this final rule. These differences appear to explain the discrepancy between FDEP and EPA estimates.

B. Incrementally Impaired Waters

To estimate nonpoint source incremental costs associated with State control requirements that may be necessary to assure attainment of designated uses, EPA first removed from further consideration any waters the State of Florida has already determined to be impaired or has established a TMDL and/or BMAP because these waters were considered part of the baseline for this analysis. EPA next identified Florida waters that may be identified as incrementally impaired using the criteria of this final rule, and then identified the watersheds surrounding those incrementally impaired waters. EPA analyzed FDEP's database of ambient water quality monitoring data and compared monitoring data for each waterbody with EPA's new criteria for TN and TP in lakes and flowing waters, and nitrate+nitrite concentrations in springs. To account for streams that may have downstream protection values (DPVs) as applicable criteria, streams intersecting lakes were assigned the applicable lake criteria. Costs may be overestimated because the method does not distinguish between upstream and downstream intersecting streams. Thus DPVs and additional controls may have been attributed to streams downstream of an impaired lake. EPA compiled the most recent five years of monitoring data, calculated the annual geometric mean for each waterbody identified by a waterbody identification number (WBID), and identified waters as incrementally impaired if they exceeded the applicable criteria in this final rule.

[175] Florida Department of Environmental Protection, 2010, "FDEP Review of EPA's 'Preliminary Estimate of Potential Compliance Costs and Benefits Associated with EPA's Proposed Numeric Nutrient Criteria for Florida'," p. 3.

TABLE VI(B)—SUMMARY OF POTENTIAL INCREMENTALLY IMPAIRED WATERS

Category	Number of water bodies			Total
	Lake	Stream [a]	Spring	
Total in State	1,310	3,901	126	5,337
Not Listed/Covered by TMDL [b]	1,099	3,608	119	4,826
Water Quality Monitoring Data for Nutrients [c]	878	1,273	72	2,223
Sufficient Data Available [d]	655	930	72	1,657
Potentially Exceeding Criteria (incrementally impaired) [e]	148	153	24	325

[a] Includes blackwater.
[b] As reported in TMDL documents and FDEP.
[c] Data within last 5 years meeting data quality requirements.
[d] Annual geometric means based on at least 4 samples with one sample from May to September and one sample from October to April in a given year.
[e] Annual geometric mean exceeding the applicable criteria more than once in a three year period.

C. Non-Point Source Costs

To estimate the potential incremental costs associated with controlling nitrogen/phosphorus pollution from non-point sources, EPA identified land areas near incrementally impaired waters using GIS analysis. EPA first identified all the 10-digit hydrologic units (HUCs) in Florida that contain at least a *de minimus* area of an incrementally impaired WBID (WBIDs were GIS polygons), and excluding those HUCs that contain at least a *de minimus* area of a currently impaired WBID. EPA then identified land uses using GIS analysis of data obtained from the State of Florida.[176]

1. Costs for Urban Runoff

EPA's GIS analysis indicates that urban land (excluding land for industrial uses covered under point sources) accounts for approximately seven percent of the land near incrementally impaired waters. EPA's analysis also indicates that urban runoff is already regulated on approximately one half of this land under EPA's storm water program requiring municipal storm sewer system (MS4) NPDES permits. Florida has a total of 28 large (Phase I) permitted MS4s serving greater than 100,000 people and 131 small (Phase II) permitted MS4s serving less than 100,000 people. MS4 permits generally do not have numeric nutrient limits, but instead rely on implementation of BMPs to control pollutants in storm water to the maximum extent practicable. Even those MS4s in Florida discharging to impaired waters or under a TMDL currently do not have numeric limits for any pollutant.

In addition to EPA's storm water program, several existing State rules are intended to reduce pollution from urban runoff. Florida's Urban Turf Fertilizer rule (administered by FDACS) requires a reduction in the amount of nitrogen and phosphorus that can be applied to lawns and recreational areas. Florida's 1982 storm water rule (Chapter 403 of Florida statues) requires storm water from new development and redevelopment to be treated prior to discharge through the implementation of BMPs. The rule also requires that older systems be managed as needed to restore or maintain the beneficial uses of waters, and that water management districts establish and implement other storm water pollutant load reduction goals. In addition, Chapter 62–40, F.A.C., "Water Resource Implementation Rule," establishes that storm water design criteria adopted by FDEP and the water management districts shall achieve at least 80% reduction of the average annual load of pollutants that cause or contribute to violations of WQS (95% reduction for outstanding natural resource waters). The rule also states that the pollutant loading from older storm water management systems shall be reduced as necessary to restore or maintain the designated uses of waters.

Although urban runoff is currently regulated under the statutes and rules described above, this final rule may indirectly result in changes to MS4 NPDES permit requirements for urban runoff so that Florida waters meet State designated uses. However, the combination of additional pollution controls required will likely depend on the specific nutrient reduction targets, the controls already in place, and the relative amounts of nitrogen/phosphorus pollution contained in urban runoff at each particular location. Because storm water programs are usually implemented using an iterative approach, with the installation of controls followed by monitoring and re-evaluation to determine the need for additional controls, estimating the complete set of pollution controls required to meet a particular water quality target would require site-specific analysis.

Although it is difficult to predict the complete set of potential additional storm water controls that may be required to meet the numeric criteria that supports State designated uses in incrementally impaired waters, EPA estimated potential costs for additional treatment by assessing the amount of urban land that may require additional pollution controls for storm water. FDEP has previously assumed that all urban land developed after adoption of Florida's 1982 storm water rule would be in compliance with this final rule.[177] Using this same assumption, EPA used GIS analysis of land use data obtained from the State of Florida [178] to identify the amount of remaining urban land located near incrementally impaired waters. Using this procedure, EPA estimated that up to 48,100 acres of Phase I MS4 urban land, 30,700 acres of Phase II MS4 urban land, and 30,600 acres of non-MS4 urban land may require additional storm water controls. EPA estimated costs of implementing controls for Phase I MS4 urban land based on a range of acres with 48,100 acres as the upper bound and zero acres as the lower bound because Phase I MS4 urban land already must implement controls to the "maximum extent practicable" and may not require additional controls if existing requirements are already fully implemented.

The cost of storm water pollution controls can vary widely. FDEP has assessed the cost of completed storm water projects throughout the State in dollars per acre treated.[179] Capital costs

[176] Florida Geological Data Library, 2009, "GIS Data: WBIDs," available electronically at: *http://www.fgdl.org/download/index.html.*

[177] Florida Department of Environmental Protection, 2010, "FDEP Review of EPA's 'Preliminary Estimate of Potential Compliance Costs and Benefits Associated with EPA's Proposed Numeric Nutrient Criteria for Florida'," p. 9.

[178] Florida Geological Data Library, 2009.

[179] Florida Department of Environmental Protection, 2010, appendix 3.

range from $62 to $60,300 per acre treated, with a median cost of $6,800 per acre. EPA multiplied FDEP's median capital cost per acre by the number of acres identified as requiring controls to estimate the potential additional storm water control costs that may be needed to meet the numeric criteria in this rule. EPA also used FDEP's estimate of operating and maintenance (O&M) costs as 5% of capital costs, and annualized capital costs using FDEP's discount rate of 7% over 20 years. EPA estimates the total annual cost for additional storm water controls could range between approximately $60.5 and $108.0 million per year. The following table summarizes these estimates.

TABLE VI(C)(1)—POTENTIAL INCREMENTAL URBAN STORM WATER COST SCENARIOS

Land type	Acres needing controls [a]	Capital cost (millions $) [b]	O&M cost (millions $) [c]	Annual cost (millions $) [d]
MS4 Phase I Urban	0–48,100	$0–$329.1	$0–$16.4	$0–$47.5
MS4 Phase II Urban	30,700	$210.0	$10.5	$30.3
Non-MS4 Urban	30,600	$208.8	$10.4	$30.2
Total	61,300–109,400	$418.8–$747.0	$20.9–$37.4	$60.5–$108.0

[a] Phase I MS4s range represents implementation of BMPs to the MEP resulting in compliance with EPA's rule or controls needed on all pre-1982 developed land; Phase II MS4s and urban land outside of MS4s represent controls needed on all pre-1982 developed land that is not low density residential.
[b] Represents acres needing controls multiplied by median unit costs of storm water retrofit costs obtained from FDEP.
[c] Represents 5% of capital costs.
[d] Capital costs annualized at 7% over 20 years plus annual O&M costs.

Using Florida's 2009 draft criteria as the baseline, potential incremental costs for urban storm water are estimated to range from $13.7 million per year to $27.2 million per year.

Several organizations in Florida developed alternative estimates of compliance costs for EPA's proposed rule that were substantially higher than EPA's estimated costs for urban storm water. EPA disagrees with these cost estimates because they utilized incorrect assumptions about the areas that would have to implement controls. For example, FDEP estimated costs for urban storm water controls at $1.97 billion per year.[180] However, FDEP estimated costs for pollution controls on urban land in watersheds that may not be listed as impaired, have already been listed as impaired, or will require controls under existing rules (*e.g.* land currently permitted under EPA's MS4 storm water program). In contrast, EPA estimated costs for urban storm water controls only for urban land with storm water flows to waters that may be listed as impaired as a result of this rule. This difference appears to explain the discrepancy between FDEP and EPA estimates.

2. Agricultural Costs

EPA's GIS analysis of land use indicates that agriculture accounts for about 19 percent of the land near incrementally impaired waters. Agricultural runoff can be a source of phosphorus and nitrogen to lakes and streams through the application of fertilizer to crops and pastures and from animal wastes. Some agricultural practices may also contribute nitrogen and phosphorus to groundwater aquifers that supply springs. For waters impaired by nitrogen/phosphorus pollution, the 1999 Florida Watershed Restoration Act established that agricultural BMPs should be the primary instrument to implement TMDLs. Thus, additional waters identified by the State as impaired under this rule may result in State requirements or provisions to reduce the discharge of nitrogen and/or phosphorus to incrementally impaired waters through the implementation of BMPs.

EPA estimated the potential costs of additional agricultural BMPs by evaluating land use data obtained from Florida's five water management districts. BMP programs designed for each type of agricultural operation and their costs were taken from a study of agricultural BMPs to help meet TMDL targets in the Caloosahatchee River, St. Lucie River, and Lake Okeechobee watersheds.[181] Three types of BMP programs were identified in this study. The first program, called the "Owner Implemented BMP Program," consists of a set of BMPs that land owners might implement without additional incentives. The second program, called the "Typical BMP Program," is the set of BMPs that land owners might implement under a reasonably funded cost share program or a modest BMP strategy approach. The third program, called the "Alternative Program," is a more expensive program designed to supplement the "Owner Implemented Program" and "Typical Program" if additional reductions are necessary.

The BMPs in the "Owner Implemented Program" and "Typical Program" are similar to the BMPs adopted by FDACS. EPA has found no indication that the "Alternative BMP Program," which includes storm water chemical treatment, has been required in historically nutrient impaired watersheds with significant contributions from agriculture for which TMDLs have been developed (*e.g.* Lake Okeechobee). Therefore, for purposes of this analysis, EPA believes it is reasonable to assume that nutrient controls for agricultural sources are best represented by the "Owner Implemented Program" and "Typical Program" described in the study used here.[182] EPA estimated potential incremental costs of BMPs by multiplying the number of acres in each agricultural category by the sum of unit costs for the "Owner Implemented Program" and "Typical Program." The following table summarizes the potential incremental costs of BMPs on agricultural lands near incrementally impaired lakes and streams for each agricultural category.

[180] Florida Department of Environmental Protection, 2010, p. 3.

[181] Soil and Water Engineering Technology, 2008, "Nutrient Loading Rates, Reduction Factors and Implementation Costs Associated with BMPs and Technologies," (report prepared for South Florida Water Management District).

[182] Soil and Water Engineering Technology, 2008.

TABLE VI(C)(2)(a)—POTENTIAL INCREMENTAL BMP COSTS FOR LAKES AND STREAMS

Agricultural category	Area (acres)[a]	"Owner implemented program" plus "typical program" unit costs ($/ac/yr)[e]	Total "owner implemented program" and "typical program" costs ($/yr)
Animal Feeding	1,814–1,846	18.56	33,671–34,260
Citrus	15,482–27,343	156.80	2,427,652–4,287,343
Cow Calf Production (Improved Pastures)	153,978–168,665	15.84	2,439,007–2,671,656
Cow Calf Production (Unimproved Pastures)	49,054–51,057	4.22	207,203–215,663
Cow Calf Production (Rangeland and Wooded)	74,449–75,790	4.22	314,474–320,136
Row Crop	7,846–9,808	70.40	552,352–690,453
Cropland and Pastureland (general).[b]	152,976–160,814	27.26	4,169,512–4,383,135
Sod/Turf Grass	2,007	35.20	70,631
Ornamental Nursery	840	70.00	58,783
Dairies	583–621	334.40	194,803–207,777
Horse Farms	1,632	15.84	25,857
Field Crop (Hayland) Production	194,181–215,168	18.56	3,603,996–3,993,521
Other Areas[c]	54,499–67,364	18.56	1,011,500–1,250,281
Total[d]	709,340–782,954		15,109,436–18,209,496

[a] Based on GIS analysis of land use data from five water management districts (for entire State) and FDACS BMP program NOI GIS data layer. Low end reflects acres in incrementally impaired HUCs (that are not included in HUCs for baseline impairment) that are not enrolled in BMPs under FDACS; high end reflects all acres in incrementally impaired HUCs, regardless of FDACS BMP enrollment.
[b] "Owner program" and "Typical Program" BMP unit costs based on average costs for improved pastures, unimproved/wooded pasture, row crops, and field crops.
[c] Includes FLUCCS Level 3 codes 2160, 2200, 2230, 2400, 2410, 2500, 2540, and 2550.
[d] Excludes land not in production.
[e] Soil and Water Engineering Technology, 2008, Nutrient Loading Rates, Reduction Factors and Implementation Costs Associated with BMPs and Technologies, Report prepared for South Florida Water Management District.

In addition to estimating potential costs associated with agricultural BMPs to reduce nitrogen/phosphorus pollution to lakes and streams as described above, EPA estimated potential costs associated with BMPs to protect groundwater aquifers that supply water to springs. Fertilizer application and other agricultural practices can significantly increase nutrient loadings to springs, especially those springs supplied by relatively large groundwater aquifers. EPA evaluated the potential incremental costs to meet the numeric criteria in this final rule for springs by assuming that all applicable agricultural operations may be identified for implementation of nutrient management. Nutrient management reduces over application of fertilizers by determining realistic yield expectations, the nitrogen requirements necessary to obtain those yields, and adjusting application methods and timing to minimize nitrogen pollution.

Nutrient management is a cost-effective way to reduce groundwater nitrogen, and may even result in cost savings to some farmers by reducing unnecessary fertilizer application. Therefore, for the purpose of this analysis, EPA assumed that all agricultural operations applying fertilizer to land would implement a nutrient management program, even those operations that are not associated with incrementally impaired waters. To estimate the potential costs of nutrient management, EPA estimated the amount of agricultural land where nutrient management could be applicable. EPA identified general agriculture[183] and specialty crops[184] as agricultural categories appropriate for nutrient management. EPA then used GIS analysis of land use data obtained from the State of Florida[185] to identify the land areas categorized as general agriculture or specialty crops. Approximately 4.9 million acres of agricultural land was identified as general agriculture and 1 million acres was identified as specialty crops. EPA further analyzed this agricultural land to identify the land near waters already listed as impaired for nutrients or under a TMDL. Similar to point sources, EPA assumed that nonpoint sources under an existing TMDL are currently meeting their load allocation requirements and would not incur additional costs, and costs to nonpoint sources associated with waters that are currently listed as impaired for nutrients are not attributable to this final rule because those costs would be incurred absent the rule (under the baseline). EPA also removed from this analysis land associated with incrementally impaired waters to avoid double counting the costs of BMPs that were already estimated to protect lakes and streams as described above. As a result of this analysis, approximately 1 million acres of general agriculture and 0.12 million acres of specialty crops was identified as land that may need to implement a nutrient management program to meet the numeric criteria for Florida springs in this final rule. Using unit costs of $10 per acre for general agriculture and $20 per acre for specialty crops obtained from Florida's Environmental Quality Incentive Program,[186] EPA estimated the annual cost of nutrient management could be approximately $4.7 million per year. The following table summarizes the estimated potential incremental costs of BMPs on agricultural lands to protect State designated uses of springs on the basis of the criteria in this final rule.

[183] Cropland and pastureland, cow calf production (improved pastures), cropland and pastureland (general), dairies, horse farms, and field crop (hayland) production.

[184] Citrus, row crops, sod/turf grass, and ornamental nursery.

[185] Florida Geological Data Library, 2009.

[186] Florida Environmental Quality Incentive Program, 2009, "FY 2009 Statewide Payment Schedules," available electronically at: *ftp://ftp-fc.sc.egov.usda.gov/FL/eqip/EQIP_FY2009PaySched_STATEWIDE_FINAL.pdf.*

TABLE VI(C)(2)(b)—POTENTIAL INCREMENTAL BMP COSTS FOR SPRINGS

Nutrient management program type	Total acres in Florida[a]	Acres identified for nutrient management[b]	Unit cost ($/acre)	Total cost	Annual cost ($/year)[c]
General Agriculture	4,885,643	1,003,973	$10	$10,039,729	$3,825,656
Specialty Crop	1,057,107	120,558	20	2,411,163	918,778
Total	5,942,750	1,124,531		12,450,892	4,744,433

[a] Excludes unimproved and woodland pastures, abandoned groves, aquaculture, tropical fish farms, open rural lands, and fallow cropland.
[b] Calculated by subtracting agricultural land near incrementally impaired waters needing controls and agricultural land types participating in FDACS BMP program (assuming all Tri-county agricultural area land is regular nutrient management land) from total land use area in Florida.
[c] Costs annualized at 7% over 3 years on basis of 3 year useful life.

The following table summarizes the total estimated potential incremental costs of BMPs on agricultural lands to meet the numeric criteria.

TABLE VI(C)(2)(c)—POTENTIAL ANNUAL INCREMENTAL COMPLIANCE COSTS FOR AGRICULTURE

Waterbody type	Applicable acres	Annual costs
Lakes and Streams	709,340–782,954	$15,109,400–$18,209,500
Springs	1,124,531	$4,744,400
Total	1,833,871–1,907,485	$19,853,900–$22,953,900

Using Florida's 2009 draft criteria as the baseline, potential incremental costs to agriculture are estimated to range from − $2.4 million per year (a negative cost represents a cost savings) to $2.1 million per year.

Several organizations in Florida developed alternative estimates of compliance costs for EPA's proposed rule that were substantially higher than EPA's estimated costs for agriculture. EPA disagrees with these cost estimates because they use incorrect assumptions that overestimate costs. For example, the FDACS estimated that costs for agriculture would be approximately $0.9 billion to $1.6 billion per year.[187] However, FDACS estimated BMP costs for all 13.6 million acres of agricultural land in the State of Florida. This land includes watersheds where waters are not expected to become listed as impaired due to this final rule (including coastal and estuarine watersheds), have already been listed as impaired, or will require controls under existing rules (*e.g.* animal feeding operations) and thus are not potentially affected by the rule. A portion of the agricultural land used by FDACS to estimate costs includes 4.8 million acres of forest, 98.1% of which the State of Florida has claimed current BMPs effectively protect surface waters[188] and thus EPA assumes will not require further controls. FDACS also estimated costs using the highest cost Alternative BMP program. The Alternative BMP Program, which includes storm water chemical treatment, is not yet required in historically nutrient-impaired watersheds with significant contributions from agriculture. Thus, it is uncertain whether such controls would be necessary or required to meet the new numeric criteria which are intended to implement Florida's existing narrative criteria. In contrast, EPA estimated costs for BMPs that are likely to be necessary, and only on the agricultural land identified as incrementally impaired under this final rule (although costs could be higher in some cases if further reductions are found to be necessary). These differences appear to explain the discrepancy between FDACS and EPA estimates.

The alternative BMP program, which includes storm water chemical treatment, is not yet required in the study basins which have significant contributions from agriculture. Thus, for this analysis, EPA assumed that nutrient controls for agricultural sources are best represented by the owner/typical programs.

3. Septic System Costs

Some nutrient reductions from septic systems may be necessary for incrementally impaired waters to meet the numeric nutrient criteria in this final rule. Several nutrient-related TMDLs in Florida identify septic systems as a significant source of nitrogen/phosphorus pollution. Although properly operated and maintained systems can provide treatment equivalent to secondary wastewater treatment,[189] even properly functioning septic systems can be expected to contribute to nitrogen/phosphorus pollution at some locations.[190] Some of the ways to address pollution from septic systems may include greater use of inspection programs and repair of failing systems, upgrading existing systems to advanced nutrient removal, installation of decentralized cluster systems where responsible management entities would ensure reliable operation and maintenance, and connecting households and businesses to wastewater treatment plants. On the basis of current practice in the State of

[187] Florida Department of Agriculture and Consumer Services, 2010, "Consolidated Comments on Proposed EPA Numeric Nutrient Criteria for Florida's Lakes and Flowing Waters," p. 1, available electronically at: *http://www.floridaagwaterpolicy.com/PDF/FINAL_FDACS_Consolidated_Comments_on_Docket_ID_No_EPA_HQ_OW_2009_0596.pdf.*

[188] Florida Division of Forestry, Department of Agriculture and Consumer Services, 2010, "Silviculture Best Management Practices: 2009 Implementation Survey Report," available electronically at: *http://www.fl-dof.com/publications/2009_BMP_survey_report.pdf.*

[189] Petrus, K., 2003, "Total Maximum Daily Load for the Palatlakaha River to Address Dissolved Oxygen Impairment, Lake County, Florida," (Florida Department of Environmental Protection), available electronically at: *http://www.dep.state.fl.us/water/tmdl/docs/tmdls/final/gp1/palatlakaha_river_do_tmdl.pdf.*

[190] Florida Department of Environmental Protection, 2006, "TMDL Report. Nutrient and Unionized Ammonia TMDLs for Lake Jesup, WBIDs 2981 and 2981A," available electronically at: *http://www.dep.state.fl.us/water/tmdl/docs/tmdls/final/gp2/lake-jessup-nutr_ammonia-tmdl.pdf.*

Florida, EPA assumed that the most likely strategy to reduce nutrients loads from septic systems would be to upgrade existing conventional septic systems to advanced nutrient removal systems.

Septic systems in close proximity to surface waters are more likely to contribute nutrient loads to waters than distant septic systems. Florida Administrative Code provides that in most cases septic systems should be located at least 75 feet from surface waters (F.A.C. 64E–6.005(3)). In addition, many of Florida's existing nutrient-related TMDLs identify nearby failing septic systems as contributing to nutrient impairments in surface waters.

For this economic analysis, EPA assumed that some septic systems located near incrementally impaired lakes and streams may be required to upgrade to advance nutrient removal systems. However, the distance that septic systems can be safely located relative to these surface waters depends on a variety of site-specific factors. Because of this uncertainty, EPA conservatively assumed that septic systems located within 500 feet of any lake or stream in watersheds associated with incrementally impaired lakes or streams [191] may be identified for upgrade from conventional to advanced nutrient removal systems.

EPA identified the number of septic systems within 500 feet of any lake or stream in watersheds associated with incrementally impaired lakes and streams using GIS analysis on data obtained from the Florida Department of Health [192] that provides the location of active septic systems in the State. This analysis yielded 8,224 active septic systems that may potentially need to be upgraded from conventional to advanced nutrient removal systems to meet the numeric nutrient criteria in this final rule.

EPA evaluated the cost of upgrading existing septic systems to advanced nutrient removal systems. Upgrade costs range from $2,000 to $6,500 per system. For O&M costs, EPA relied on a study that compared the annual costs associated with various septic system treatment technologies including conventional onsite sewage treatment and disposal system and fixed film activated sludge systems.[193] This study estimated the incremental O&M costs for an advanced system to be $650 per year. Thus, based on annual O&M costs of $650 and annualizing capital costs at 7% over 20 years, annual costs could range from approximately $800 to $1,300 for each upgrade. EPA estimated the total annual costs of upgrading septic systems by multiplying this range of unit costs with the number of systems identified for upgrade. Using this method, total annual costs for upgrading septic systems to meet State designated uses could range from $6.6 million per year to $10.7 million per year.

Using Florida's 2009 draft criteria as the baseline, potential incremental costs to upgrade septic systems are estimated to range from $1.3 million per year to 2.2 million per year.

Several organizations in Florida developed alternative estimates of compliance costs for septic systems in EPA's proposed rule that were substantially higher than EPA's estimated costs. EPA disagrees with these cost estimates because they used incorrect assumptions that overestimate costs. For example, FDEP estimated that the costs related to septic systems would be approximately $0.9 billion per year to 2.9 billion per year.[194] However, FDEP assumed that 1,687,500 septic systems would require complete replacement (calculated as the proportion of all septic systems in the State of Florida on lots less than 3 acres assumed to discharge to fresh waters because all urban storm water discharges to freshwaters in that proportion). In contrast, EPA estimated costs to upgrade 8,224 septic systems to advanced nutrient removal systems that GIS analysis identified as located within 500 feet of any water within an incrementally impaired watershed.

D. Governmental Costs

This final rule may result in the identification of additional impaired waters that would require the development of additional TMDLs. As the principal State regulatory agency implementing water quality standard, the State of Florida may incur costs related to developing additional TMDLs. EPA's analysis identified 325 incrementally impaired waters potentially associated with this final rule. Because current TMDLs in Florida include an average of approximately two water bodies each, EPA estimates that the State of Florida may need to develop and adopt approximately 163 additional TMDLs. A 2001 EPA study found that the cost of developing a TMDL could range between $6,000 and $154,000, with an average cost of approximately $28,000.[195] [196] The low end of the range reflects the typical cost associated with TMDLs that are the easiest to develop and/or have the benefit of previous TMDL development for other pollutants. Because most of the incrementally impaired waters in EPA's analysis exceeded the criteria for both nitrogen and phosphorus, EPA assumed that TMDLs would need to be developed for both nitrogen and phosphorus. Under this assumption, EPA estimated the average TMDL cost to be approximately $47,000 ($28,000 on average for one pollutant, plus $6,000 on average for the other pollutant, and adjusting for inflation). For 163 TMDLs, total costs could be approximately $7.7 million. FDEP currently operates its TMDL schedule on a five-phase cycle that rotates through the five basins over five years. Under this schedule, completion of TMDLs for high priority waters will take 9 years; it will take an additional 5 years to complete the process for medium priority waters. Thus, assuming all the incremental impairments are high priority and FDEP develops the new TMDLs over a 9-year period, annual costs could be approximately $851,000 per year. Using Florida's 2009 draft criteria as the baseline, potential incremental costs to develop additional TMDLs could be approximately $261,000 per year.

Should the State of Florida submit current TMDL targets as Federal site specific alternative criteria (SSAC) for EPA review and approval, EPA believes it is reasonable to assume that information used in the development of the TMDLs will substantially reduce the time and effort needed to provide a scientifically defensible justification for such applications. Thus, EPA assumed that incremental costs associated with SSAC, if any, would be minimal.

Similarly, State and local agencies regularly monitor TN and TP in ambient waters. These data are the basis for the extensive IWR database the State of Florida maintains and which provided baseline water quality data for EPA's analyses. Because Florida is currently

[191] In this analysis EPA considered septic systems within 500 feet of any lake or stream in an incrementally impaired watershed rather than only within 500 feet of an incrementally impaired lake or stream to account for the possibility of some downstream transport of nutrients from nearby streams that may not themselves be classified as incrementally impaired.

[192] Florida Department of Health, 2010, "Bureau of Onsite Sewage GIS Data Files," available electronically at: *http://www.doh.state.fl.us/Environment/programs/EhGis/EhGisDownload.htm.*

[193] Chang, N., M. Wanielista, A. Daranpob, F. Hossain, Z. Xuan, J. Miao, S. Liu, Z. Marimon, and S. Debusk, 2010, "Onsite Sewage Treatment and Disposal Systems Evaluation for Nutrient Removal," (Stormwater Management Academy, University of Central Florida).

[194] Florida Department of Environmental Protection, 2010, p. 3.

[195] U.S. EPA, 2001, "The National Costs of the Total Maximum Daily Load Program (Draft Report)," (EPA–841–D–01–003).

[196] EPA did not adjust these estimates to account for potential reductions in resources required to develop TMDLs as a result of this final rule.

monitoring TN, TP, and chlorophyll *a* concentrations in many waters, EPA assumed that this final rule is unlikely to have a significant impact on costs related to water quality monitoring activities.

E. Benefits

Elevated concentrations of nutrients in surface waters can result in adverse ecological effects and negative economic impacts. Excess nutrients in water can cause eutrophication, which can lead to harmful (sometimes toxic) algal blooms, loss of rooted plants, and decreased dissolved oxygen, which can lead to adverse impacts on aquatic life, fishing, swimming, wildlife watching, camping, and drinking water. Excess nutrients can also cause nuisance surface scum, reduced food for herbivorous wildlife, fish kills, alterations in fish communities, and unsightly shorelines that can decrease property values. This final rule will help reduce nitrogen and phosphorus concentrations in lakes and flowing waters in Florida, and help improve ecological function and prevent further degradation that can result in substantial economic benefits to Florida citizens. EPA's economic analysis document entitled: *Economic Analysis of Final Water Quality Standards for Nutrients for Lakes and Flowing Waters in Florida* describes many of the potential benefits associated with meeting the water quality standards for nitrogen/phosphorus pollution in this rule.

Florida waters have historically provided an abundance of recreational opportunities that are a vital part of the State's economy. In 2007, over 4.3 million residents and over 5.8 million visitors participated in recreational activities related to freshwater beaches in Florida.[197] Of these residents and visitors, over 2.7 million residents and approximately 1 million visitors used freshwater boat ramps, over 3 million residents and over 900,000 visitors participated in freshwater non-boat fishing, and over 2.6 million residents and almost 1 million visitors participated in canoeing and kayaking. Florida also ranks first in the nation in boat registrations with 973,859 recreational boats registered across the State.

Tourism comprises one of the largest sectors of the Florida economy. In 2000, there were over 80.9 million visitors to the State of Florida, accounting for an estimated $65 billion in tourism spending.[198] In 2008, tourism spending resulted in approximately $3.9 billion in State sales tax revenues and contributed to the direct employment of more than 1 million Florida residents.[199] Florida has ranked first in the nation for the number of in-State anglers, angler expenditures, angler-supported jobs, and State and local tax revenues derived from freshwater fishing.[200] In 2006, total fishing-related expenditures by residents and nonresidents were more than $4.3 billion.[201] In addition, Florida's freshwater springs are an important inter- and intra-State tourist attraction.[202] In 2002, Blue Springs State Park estimated over 300,000 visitors per year.

Nitrogen/phosphorus pollution has contributed to severe water quality degradation of Florida waters. In 2010, the State of Florida reported approximately 1,918 miles of rivers and streams, and 378,435 acres of lakes that were known to be impaired by nitrogen/phosphorus pollution (the actual number of waters impaired for nutrients may be higher because many waters were not assessed).[203] As water quality declines, water resources have less recreational value. Waters impaired by nitrogen/phosphorus pollution may become unsuitable for swimming and fishing, and in some cases even unsuitable for boating. Nutrient-impaired waters also are less likely to support native plant and animal species, further lowering their value as tourist destinations.[204] Drinking water supplies may also be more expensive to treat as a result of nutrient impairments. Also, Florida citizens that depend on individual wells for their drinking water may need to consider whether on-site treatment is necessary to reduce elevated nitrate+nitrite levels. Freshwater springs are particularly at risk due to nitrate+nitrite.[205] [206] Silver Springs, the largest of Florida's springs, has experienced reduced ecosystem health and productivity over the past half century, due largely to nitrate+nitrite.[207] Nutrient impairment, characterized by algal blooms, reduced numbers of native species, and lower water quality, in turn leads to reduced demand and lower values for these resources.

Some of the benefits of reducing nitrogen and phosphorus concentrations can be monetized, at least in part, by translating these changes into an indicator of overall water quality (water quality index) and valuing these improvements in terms of willingness to pay (WTP) for the types of uses that are supported by different water quality levels. For this analysis, EPA used a Water Quality Index (WQI) approach to link specific pollutant levels with suitability for particular recreational uses. Using Florida water quality data, available information on WTP, and an analytical approach described in EPA's accompanying economic assessment report and supporting references, EPA estimated potential changes that would result from implementation of this final rule and their value to a distribution of full-time and part-time Florida residents. This approach recognizes that there are differences in WTP among a population and values for households. Using the mid-point WTP and current conditions as the baseline, total monetized benefits are estimated to be approximately $21.7 million per year for improvements to flowing waters and $6.6 million per year for improvements to lakes for a total of $28.2 million per year. Although these monetized benefits estimates do not account for all potential economic benefits, they help to partially demonstrate the economic importance of restoring and protecting Florida waters from the impacts of nitrogen/phosphorus pollution.

[197] Florida Department of Environment, 2008, "State Comprehensive Outdoor Recreation Plan (SCORP)," available electronically at: *http://www.dep.state.fl.us/parks/planning/default.htm.*

[198] VISIT Florida, 2010, available electronically at: *http://media.visitflorida.org/research.php.*

[199] VISIT Florida, 2010.

[200] Bonn, Mark A. and Frederick W. Bell., 2003, Economic Impact of Selected Florida Springs on Surrounding Local Areas. For Florida Department of Environmental Protection. Available electronically at: *http://www.dep.state.fl.us/springs/reports/files/EconomicImpactStudy.doc.*

[201] 2006 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation. Florida. U.S. Department of the Interior, Fish and Wildlife Service, and U.S. Department of Commerce, U.S. Census Bureau. Available electronically at: *http://myfwc.com/docs/Freshwater/2006_Florida_NationalSurvey.pdf.*

[202] Florida Department of Environmental Protection, 2008.

[203] Florida Department of Environmental Protection, 2010, "Integrated Water Quality Assessment for Florida: 2010 305(b) and 303(d) List Update," available electronically at: *http://www.dep.state.fl.us/water/docs/2010_Integrated_Report.pdf.*

[204] Zheng, Lei and Michael J. Paul., 2006, *Effects of Eutrophication on Stream Ecosystems.* Available electronically at: *http://n-steps.tetratech-ffx.com/PDF&otherFiles/literature_review/Eutrophication%20effects%20on%20streams.pdf.*

[205] Florida Department of Environment, "Deep Trouble: Getting to the Source of Threats to Springs," accessed on October 1, 2010 at: *http://www.floridasprings.org/protection/threats/.*

[206] Munch, D.A., D.J. Toth, C. Huang, J.B. Davis, C.M. Fortich, W.L. Osburn, E.J. Phlips, E.L. Quinlan, M.S. Allen, M.J. Woods, P. Cooney, R.L. Knight, R.A. Clarke and S.L. Knight., 2006, "Fifty-year retrospective study of the ecology of Silver Springs, Florida," (SJ2007–SP4).

[207] Florida Department of Environment, 2008, Summary and Synthesis of the Available Literature on the Effects of Nutrients on Spring Organisms and Systems," available at: *http://www.dep.state.fl.us/springs/reports/files/UF_SpringsNutrients_Report.pdf.*

F. Summary

The following table summarizes EPA's estimates of potential incremental costs and benefits associated with additional State requirements to meet the numeric criteria that supports State designated uses. Because of uncertainties in the pollution controls ultimately implemented by the State of Florida, actual costs may vary depending on the procedures for assessing waters for compliance and the site-specific source reductions needed to meet the new numeric criteria.

TABLE VI(F)(a)—SUMMARY OF POTENTIAL ANNUAL COSTS
[millions of 2010 dollars per year]

Source sector	Annual costs
Municipal Waste Water Treatment Plants.	$22.3–$38.1
Industrial Dischargers	$25.4
Urban Storm Water	$60.5–$108.0
Agriculture	$19.9–$23.0
Septic Systems	$6.6–$10.7
Government/Program Implementation.	$0.9
Total	$135.5–$206.1

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action." Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action. This final rule does not establish any requirements directly applicable to regulated entities or other sources of nitrogen/phosphorus pollution. Moreover, existing narrative water quality criteria in State law already require that nutrients not be present in waters in concentrations that cause an imbalance in natural populations of flora and fauna in lakes and flowing waters in Florida.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b). It does not include any information collection, reporting, or record-keeping requirements.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this action on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

Under the CWA WQS program, States must adopt WQS for their waters and must submit those WQS to EPA for approval; if the Agency disapproves a State standard and the State does not adopt appropriate revisions to address EPA's disapproval, EPA must promulgate standards consistent with the statutory requirements. EPA also has the authority to promulgate WQS in any case where the Administrator determines that a new or revised standard is necessary to meet the requirements of the Act. These State standards (or EPA-promulgated standards) are implemented through various water quality control programs including the NPDES program, which limits discharges to navigable waters except in compliance with an NPDES permit. The CWA requires that all NPDES permits include any limits on discharges that are necessary to meet applicable WQS.

Thus, under the CWA, EPA's promulgation of WQS establishes standards that the State implements through the NPDES permit process. The State has discretion in developing discharge limits, as needed to meet the standards. This final rule, as explained earlier, does not itself establish any requirements that are applicable to small entities. As a result of this action, the State of Florida will need to ensure that permits it issues include any limitations on discharges necessary to comply with the standards established in the final rule. In doing so, the State will have a number of choices associated with permit writing. While Florida's implementation of the rule may ultimately result in new or revised permit conditions for some dischargers, including small entities, EPA's action, by itself, does not impose any of these requirements on small entities; that is, these requirements are not self-implementing. Thus, I certify that this rule will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation of why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

This final rule contains no Federal mandates (under the regulatory provisions of Title II of the UMRA) for State, local, or Tribal governments or the private sector. The State may use these resulting water quality criteria in implementing its water quality control

programs. This final rule does not regulate or affect any entity and, therefore, is not subject to the requirements of sections 202 and 205 of UMRA.

EPA determined that this final rule contains no regulatory requirements that might significantly or uniquely affect small governments. Moreover, WQS, including those promulgated here, apply broadly to dischargers and are not uniquely applicable to small governments. Thus, this final rule is not subject to the requirements of section 203 of UMRA.

E. Executive Order 13132 (Federalism)

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. EPA's authority and responsibility to promulgate Federal WQS when State standards do not meet the requirements of the CWA is well established and has been used on various occasions in the past. The final rule will not substantially affect the relationship between EPA and the States and territories, or the distribution of power or responsibilities between EPA and the various levels of government. The final rule will not alter Florida's considerable discretion in implementing these WQS. Further, this final rule will not preclude Florida from adopting WQS that EPA concludes meet the requirements of the CWA, after promulgation of the final rule, which would eliminate the need for these Federal standards and lead EPA to withdraw them. Thus, Executive Order 13132 does not apply to this final rule.

Although section 6 of Executive Order 13132 does not apply to this action, EPA had extensive communication with the State of Florida to discuss EPA's concerns with the State's water quality criteria and the Federal rulemaking process.

F. Executive Order 13175 (Consultation and Coordination With Indian Tribal Governments)

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) EPA may not issue a regulation that has Tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by Tribal governments, or EPA consults with Tribal officials early in the process of developing the proposed regulation and develops a Tribal summary impact statement. EPA has concluded that this action may have Tribal implications. However, the rule will neither impose substantial direct compliance costs on Tribal governments, nor preempt Tribal law.

In the State of Florida, there are two Indian Tribes, the Seminole Tribe of Florida and the Miccosukee Tribe of Indians of Florida, with lakes and flowing waters. Both Tribes have been approved for treatment in the same manner as a State (TAS) status for CWA sections 303 and 401 and have Federally-approved WQS in their respective jurisdictions. These Tribes are not subject to this final rule. However, this rule may impact the Tribes because the numeric criteria for Florida will apply to waters adjacent to the Tribal waters. EPA met with the Seminole Tribe on January 19, 2010 and requested an opportunity to meet with the Miccosukee Tribe to discuss EPA's proposed rule, although a meeting was never requested by the Tribe.

G. Executive Order 13045 (Protection of Children From Environmental Health and Safety Risks)

This action is not subject to EO 13045 (62 FR 19885, April 23, 1997) because it is not economically significant as defined in EO 12866, and because the Agency's promulgation of this rule will result in the reduction of environmental health and safety risks that could present a disproportionate risk to children.

H. Executive Order 13211 (Actions That Significantly Affect Energy Supply, Distribution, or Use)

This rule is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer Advancement Act of 1995

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final rulemaking does not involve technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

J. Executive Order 12898 (Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations)

Executive Order (EO) 12898 (Feb. 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final rule does not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it will afford a greater level of protection to both human health and the environment if these numeric criteria are promulgated for Class I and Class III waters in the State of Florida.

K. Congressional Review Act

The Congressional Review Act 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A "major rule" cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule is effective March 6, 2012, except for 40 CFR 131.43(e), which is effective February 4, 2011.

List of Subjects in 40 CFR Part 131

Environmental protection, Water quality standards, Nitrogen/phosphorus pollution, Nutrients, Florida.

Dated: November 14, 2010.
Lisa P. Jackson,
Administrator.

■ For the reasons set out in the preamble, 40 CFR part 131 is amended as follows:

PART 131—WATER QUALITY STANDARDS

■ 1. The authority citation for part 131 continues to read as follows:

Authority: 33 U.S.C. 1251 *et seq.*

Subpart D—[Amended]

■ 2. Section 131.43 is added effective February 4, 2011 to read as follows:

§ 131.43 Florida.

(a)–(d) [Reserved]

(e) *Site-specific alternative criteria.* (1) The Regional Administrator may determine that site-specific alternative criteria shall apply to specific surface waters in lieu of the criteria established for Florida waters in this section, including criteria for lakes, criteria for streams, and criteria for springs. Any such determination shall be made consistent with § 131.11.

(2) To receive consideration from the Regional Administrator for a determination of site-specific alternative criteria, an entity shall submit a request that includes proposed alternative numeric criteria and supporting rationale suitable to meet the needs for a technical support document pursuant to paragraph (e)(3) of this section. The entity shall provide the State a copy of all materials submitted to EPA, at the time of submittal to EPA, to facilitate the State providing comments to EPA. Site-specific alternative criteria may be based on one or more of the following approaches.

(i) Replicate the process for developing the stream criteria in this section.

(ii) Replicate the process for developing the lake criteria in this section.

(iii) Conduct a biological, chemical, and physical assessment of waterbody conditions.

(iv) Use another scientifically defensible approach protective of the designated use.

(3) For any determination made under paragraph (e)(1) of this section, the Regional Administrator shall, prior to making such a determination, provide for public notice and comment on a proposed determination. For any such proposed determination, the Regional Administrator shall prepare and make available to the public a technical support document addressing the specific surface waters affected and the justification for each proposed determination. This document shall be made available to the public no later than the date of public notice issuance.

(4) The Regional Administrator shall maintain and make available to the public an updated list of determinations made pursuant to paragraph (e)(1) of this section as well as the technical support documents for each determination.

(5) Nothing in this paragraph (e) shall limit the Administrator's authority to modify the criteria established for Florida waters in this section, including criteria for lakes, criteria for streams, and criteria for springs.

■ 3. Section 131.43 is revised effective March 6, 2012 to read as follows:

§ 131.43 Florida.

(a) *Scope.* This section promulgates numeric criteria for nitrogen/phosphorus pollution for Class I and Class III waters in the State of Florida. This section also contains provisions for site-specific alternative criteria.

(b) *Definitions.*—(1) *Canal* means a trench, the bottom of which is normally covered by water with the upper edges of its two sides normally above water.

(2) *Clear, high-alkalinity lake* means a lake with long-term color less than or equal to 40 Platinum Cobalt Units (PCU) and Alkalinity greater than 20 mg/L $CaCO_3$.

(3) *Clear, low-alkalinity lake* means a lake with long-term color less than or equal to 40 PCU and alkalinity less than or equal to 20 mg/L $CaCO_3$.

(4) *Colored lake* means a lake with long-term color greater than 40 PCU.

(5) *Lake* means a slow-moving or standing body of freshwater that occupies an inland basin that is not a stream, spring, or wetland.

(6) *Lakes and flowing waters* means inland surface waters that have been classified as Class I (Potable Water Supplies) or Class III (Recreation, Propagation and Maintenance of a Healthy, Well-Balanced Population of Fish and Wildlife) water bodies pursuant to Rule 62–302.400, F.A.C., excluding wetlands, and are predominantly fresh waters.

(7) *Nutrient watershed region* means an area of the State, corresponding to drainage basins and differing geological conditions affecting nutrient levels, as delineated in Table 2.

(8) *Predominantly fresh waters* means surface waters in which the chloride concentration at the surface is less than 1,500 milligrams per liter.

(9) *South Florida Region* means those areas south of Lake Okeechobee and the Caloosahatchee River watershed to the west of Lake Okeechobee and the St. Lucie watershed to the east of Lake Okeechobee.

(10) *Spring* means a site at which ground water flows through a natural opening in the ground onto the land surface or into a body of surface water.

(11) *State* means the State of Florida, whose transactions with the U.S. EPA in matters related to 40 CFR 131.43 are administered by the Secretary, or officials delegated such responsibility, of the Florida Department of Environmental Protection (FDEP), or successor agencies.

(12) *Stream* means a free-flowing, predominantly fresh surface water in a defined channel, and includes rivers, creeks, branches, canals, freshwater sloughs, and other similar water bodies.

(13) *Surface water* means water upon the surface of the earth, whether contained in bounds created naturally or artificially or diffused. Water from natural springs shall be classified as surface water when it exits from the spring onto the Earth's surface.

(c) *Criteria for Florida waters*—(1) *Criteria for lakes.* (i) The applicable criteria for chlorophyll *a*, total nitrogen (TN), and total phosphorus (TP) for lakes within each respective lake class are shown on Table 1.

TABLE 1

A	B	C	
Lake Color[a] and Alkalinity	Chl-a (mg/L)[b,*]	TN (mg/L)	TP (mg/L)
Colored Lakes[c]	0.020	1.27 [1.27–2.23]	0.05 [0.05–0.16]

TABLE 1—Continued

A	B	C	
Lake Color[a] and Alkalinity	Chl-a (mg/L)[b,*]	TN (mg/L)	TP (mg/L)
Clear Lakes, High Alkalinity[d]	0.020	1.05 [1.05–1.91]	0.03 [0.03–0.09]
Clear Lakes, Low Alkalinity[e]	0.006	0.51 [0.51–0.93]	0.01 [0.01–0.03]

[a] Platinum Cobalt Units (PCU) assessed as true color free from turbidity.
[b] Chlorophyll *a* is defined as corrected chlorophyll, or the concentration of chlorophyll *a* remaining after the chlorophyll degradation product, phaeophytin *a*, has been subtracted from the uncorrected chlorophyll *a* measurement.
[c] Long-term Color > 40 Platinum Cobalt Units (PCU)
[d] Long-term Color ≤ 40 PCU and Alkalinity > 20 mg/L $CaCO_3$
[e] Long-term Color ≤ 40 PCU and Alkalinity ≤ 20 mg/L $CaCO_3$
[*] For a given waterbody, the annual geometric mean of chlorophyll *a*, TN or TP concentrations shall not exceed the applicable criterion concentration more than once in a three-year period.

(ii) Baseline criteria apply unless the State determines that modified criteria within the range indicated in Table 1 apply to a specific lake. Once established, modified criteria are the applicable criteria for all CWA purposes. The State may use this procedure one time for a specific lake in lieu of the site-specific alternative criteria procedure described in paragraph (e) of this section.

(A) The State may calculate modified criteria for TN and/or TP where the chlorophyll *a* criterion-magnitude as an annual geometric mean has not been exceeded and sufficient ambient monitoring data exist for chlorophyll *a* and TN and/or TP for at least the three immediately preceding years. Sufficient data include at least four measurements per year, with at least one measurement between May and September and one measurement between October and April each year.

(B) Modified criteria are calculated using data from years in which sufficient data are available to reflect maintenance of ambient conditions. Modified TN and/or TP criteria may not be greater than the higher value specified in the range of values in column C of Table 1 in paragraph (c)(1)(i) of this section. Modified TP and TN criteria may not exceed criteria applicable to streams to which a lake discharges.

(C) The State shall notify the public and maintain a record of these modified lake criteria, as well as a record supporting their derivation. The State shall notify EPA Region 4 and provide the supporting record within 30 days of determination of modified lake criteria.

(2) *Criteria for streams.* (i) The applicable instream protection value (IPV) criteria for total nitrogen (TN) and total phosphorus (TP) for streams within each respective nutrient watershed region are shown on Table 2.

TABLE 2

Nutrient watershed region	Instream protection value criteria	
	TN (mg/L)*	TP (mg/L)*
Panhandle West[a]	0.67	0.06
Panhandle East[b]	1.03	0.18
North Central[c]	1.87	0.30
West Central[d]	1.65	0.49
Peninsula[e]	1.54	0.12

Watersheds pertaining to each Nutrient Watershed Region (NWR) were based principally on the NOAA coastal, estuarine, and fluvial drainage areas with modifications to the NOAA drainage areas in the West Central and Peninsula Regions that account for unique watershed geologies. For more detailed information on regionalization and which WBIDs pertain to each NWR, *see* the Technical Support Document.

[a] Panhandle West region includes: Perdido Bay Watershed, Pensacola Bay Watershed, Choctawhatchee Bay Watershed, St. Andrew Bay Watershed, and Apalachicola Bay Watershed.

[b] Panhandle East region includes: Apalachee Bay Watershed, and Econfina/Steinhatchee Coastal Drainage Area.

[c] North Central region includes the Suwannee River Watershed.

[d] West Central region includes: Peace, Myakka, Hillsborough, Alafia, Manatee, Little Manatee River Watersheds; and small, direct Tampa Bay tributary watersheds south of the Hillsborough River Watershed.

[e] Peninsula region includes: Waccasassa Coastal Drainage Area, Withlacoochee Coastal Drainage Area, Crystal/Pithlachascotee Coastal Drainage Area, small, direct Tampa Bay tributary watersheds west of the Hillsborough River Watershed, Sarasota Bay Watershed, small, direct Charlotte Harbor tributary watersheds south of the Peace River Watershed, Caloosahatchee River Watershed, Estero Bay Watershed, Kissimmee River/Lake Okeechobee Drainage Area, Loxahatchee/St. Lucie Watershed, Indian River Watershed, Daytona/St. Augustine Coastal Drainage Area, St. John's River Watershed, Nassau Coastal Drainage Area, and St. Mary's River Watershed.

[*] For a given waterbody, the annual geometric mean of TN or TP concentrations shall not exceed the applicable criterion concentration more than once in a three-year period.

(ii) *Criteria for protection of downstream lakes.* (A) The applicable criteria for streams that flow into downstream lakes include both the instream criteria for total phosphorus (TP) and total nitrogen (TN) in Table 2 in paragraph (c)(2)(i) and the downstream protection value (DPV) for TP and TN derived pursuant to the provisions of this paragraph. A DPV for stream tributaries (up to the point of reaching water bodies that are not streams as defined by this rule) that flow into a downstream lake is either the allowable concentration or the allowable loading of TN and/or TP applied at the point of entry into the lake. The applicable DPV for any stream shall be determined pursuant to paragraphs (c)(2)(ii)(B), (C), or (D) of this section. Contributions from stream tributaries upstream of the point of entry location must result in attainment of the DPV at the point of entry into the lake. If the DPV is not attained at the point of entry into the lake, then the collective set of streams in the upstream watershed does not attain the DPV, which is an applicable water quality criterion for the water segments in the upstream watershed. The State or EPA may establish additional DPVs at upstream tributary locations that are consistent with attaining the DPV at the point of entry into the lake. The State or EPA also have discretion to establish DPVs to account for a larger watershed area (*i.e.*, include waters beyond the point of reaching water bodies that are not streams as defined by this rule).

(B) In instances where available data and/or resources provide for use of a scientifically defensible and protective lake-specific application of the

BATHTUB model, the State or EPA may derive the DPV for TN and/or TP from use of a lake-specific application of BATHTUB. The State and EPA are authorized to use a scientifically defensible technical model other than BATHTUB upon demonstration that use of another scientifically defensible technical model would protect the lake's designated uses and meet all applicable criteria for the lake. The State or EPA may designate the wasteload and/or load allocations from a TMDL established or approved by EPA as DPV(s) if the allocations from the TMDL will protect the lake's designated uses and meet all applicable criteria for the lake.

(C) When the State or EPA has not derived a DPV for a stream pursuant to paragraph (c)(2)(ii)(B) of this section, and where the downstream lake attains the applicable chlorophyll *a* criterion and the applicable TP and/or TN criteria, then the DPV for TN and/or TP is the associated ambient instream levels of TN and/or TP at the point of entry to the lake. Degradation in water quality from the DPV pursuant to this paragraph is to be considered nonattainment of the DPV, unless the DPV is adjusted pursuant to paragraph (c)(2)(ii)(B) of this section.

(D) When the State or EPA has not derived a DPV pursuant to paragraph (c)(2)(ii)(B) of this section, and where the downstream lake does not attain applicable chlorophyll *a* criterion or the applicable TN and/or TP criteria, or has not been assessed, then the DPV for TN and/or TP is the applicable TN and/or TP criteria for the downstream lake.

(E) The State and EPA shall maintain a record of DPVs they derive based on the methods described in paragraphs (c)(2)(ii)(B) and (C) of this section, as well as a record supporting their derivation, and make such records available to the public. The State and EPA shall notify one another and provide a supporting record within 30 days of derivation of DPVs pursuant to paragraphs (c)(2)(ii)(B) or (C) of this section.

(3) *Criteria for springs.* The applicable nitrate+nitrite criterion is 0.35 mg/L as an annual geometric mean, not to be exceeded more than once in a three-year period.

(d) *Applicability.* (1) The criteria in paragraphs (c)(1) through (3) of this section apply to lakes and flowing waters, excluding flowing waters in the South Florida Region, and apply concurrently with other applicable water quality criteria, except when:

(i) State water quality standards contain criteria that are more stringent for a particular parameter and use;

(ii) The Regional Administrator determines that site-specific alternative criteria apply pursuant to the procedures in paragraph (e) of this section; or

(iii) The State adopts and EPA approves a water quality standards variance to the Class I or Class III designated use pursuant to § 131.13 that meets the applicable provisions of State law and the applicable Federal regulations at § 131.10.

(2) The criteria established in this section are subject to the State's general rules of applicability in the same way and to the same extent as are the other Federally-adopted and State-adopted numeric criteria when applied to the same use classifications.

(e) *Site-specific alternative criteria.* (1) The Regional Administrator may determine that site-specific alternative criteria shall apply to specific surface waters in lieu of the criteria established in paragraph (c) of this section. Any such determination shall be made consistent with § 131.11.

(2) To receive consideration from the Regional Administrator for a determination of site-specific alternative criteria, an entity shall submit a request that includes proposed alternative numeric criteria and supporting rationale suitable to meet the needs for a technical support document pursuant to paragraph (e)(3) of this section. The entity shall provide the State a copy of all materials submitted to EPA, at the time of submittal to EPA, to facilitate the State providing comments to EPA. Site-specific alternative criteria may be based on one or more of the following approaches.

(i) Replicate the process for developing the stream criteria in paragraph (c)(2)(i) of this section.

(ii) Replicate the process for developing the lake criteria in paragraph (c)(1) of this section.

(iii) Conduct a biological, chemical, and physical assessment of waterbody conditions.

(iv) Use another scientifically defensible approach protective of the designated use.

(3) For any determination made under paragraph (e)(1) of this section, the Regional Administrator shall, prior to making such a determination, provide for public notice and comment on a proposed determination. For any such proposed determination, the Regional Administrator shall prepare and make available to the public a technical support document addressing the specific surface waters affected and the justification for each proposed determination. This document shall be made available to the public no later than the date of public notice issuance.

(4) The Regional Administrator shall maintain and make available to the public an updated list of determinations made pursuant to paragraph (e)(1) of this section as well as the technical support documents for each determination.

(5) Nothing in this paragraph (e) shall limit the Administrator's authority to modify the criteria in paragraph (c) of this section through rulemaking.

(f) *Effective date.* This section is effective March 6, 2012, except for § 131.43(e), which is effective February 4, 2011.

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Progress Energy Florida, Inc.

Review of Integrated Clean Air Compliance Plan

Submitted to the
Florida Public Service Commission

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Progress Energy

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Executive Summary

In the 2007 Environmental Cost Recovery Clause (ECRC) Docket (No. 070007-EI) and as reaffirmed in all subsequent ECRC Dockets (Nos. 080007-EI, 090007-EI, 100007-EI and 110007-EI), the Public Service Commission approved Progress Energy Florida's (PEF's) updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), Clean Air Visibility Rule (CAVR), and related regulatory requirements. In its 2007 final order, the Commission also directed PEF to file as part of its ECRC true-up testimony "a yearly review of the efficacy of its Plan D and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations." This report provides the required review for 2012.

The primary original components of PEF's 2006 Compliance Plan D included:

Sulfur Dioxide (SO_2):

- Installation of wet scrubbers, flue gas desulfurization system (FGD) on Crystal River Units 4 and 5
- Fuel switching at Crystal River Units 1 and 2 to burn low sulfur coal
- Fuel switching at Anclote Units 1 and 2 to burn low sulfur oil
- Purchases of SO_2 allowances

Nitrogen Oxides (NOx):

- Installation of low NOx burners (LNBs) and selective catalytic reduction (SCR) on Crystal River Units 4 and 5
- Installation of LNBs and separated over-fire air (LNB/SOFA) or alternative NOx controls at Anclote Units 1 and 2
- Purchase of annual and ozone season NOx allowances

Mercury:

- Co-benefit of wet scrubbers and SCRs at Crystal River Units 4 and 5
- Installation of powdered activated carbon (PAC) injection on Crystal River Unit 2 in 2017

As detailed in PEF's 2007 ECRC filing, PEF decided on Plan D based on a quantitative and qualitative evaluation of the ability of alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D is PEF's

most cost-effective alternative to meet the applicable regulatory requirements. The Plan was designed to meet applicable requirements by striking a balance between reducing emissions, primarily through the installation of controls on PEF's largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of emission allowance markets.

In accordance with the Commission's final order in the 2007 ECRC docket, PEF has continued to review the efficacy of Plan D and the cost-effectiveness of retrofit options in relation to expected changes in environmental regulations. With regard to efficacy, Plan D remains the cornerstone of PEF's efforts to comply with applicable air quality regulations in cost-effective manner. Crystal River Units 4 and 5 FGD and SCR projects are now in-service and the targeted environmental benefits have been met or exceeded.

Since last year's ECRC proceeding, the U.S. Court of Appeals for the District of Columbia stayed the effect of the Cross-State Air Pollution Rule (CSAPR) that EPA had recently proposed to replace CAIR, leaving CAIR in effect until the court completes its review of CSAPR. Additionally, EPA announced new Mercury and Air Toxics Standards (MATS) for emissions from coal and oil-fired electric generating units (EGUs), including, potentially, PEF's Anclote Units 1 and 2, Crystal River Units 1, 2, 4, and 5, and Suwannee Units, 1, 2, and 3. PEF has determined that the most cost-effective option for its Anclote Units 1 and 2 is to convert the units to fire 100% natural gas rather than install emission controls in order to comply with the new MATS. PEF will continue to utilize the Crystal River Unit 4 and 5 FGDs and SCRs to comply with the new MATS, but the Company is still in the process of analyzing additional control options for all of the Crystal River coal units, as well as the impact of the new MATS on Suwannee Units 1, 2 and 3.

Although EPA has begun implementation of a regulatory approach to reducing greenhouse gas (GHG) emissions through the Clean Air Act, there currently are no GHG emission standards applicable to PEF's units. Moreover, there are still no retrofit options commercially available to reduce carbon dioxide (CO_2) emissions from fossil fuel-fired EGUs.

PEF is confident that the emission controls installed pursuant to Plan D, along with compliance strategies under development, will enable the Company to achieve and maintain compliance with all applicable regulations in a cost-effective manner. PEF is in the process of evaluating additional compliance options in light of the recent adoption of MATS, the ongoing review of CSAPR, and other regulatory developments affecting fossil fuel-fired generating units.

I. Introduction

In its final Order in the 2007 ECRC Docket (No. 070007-EI) and as reaffirmed in all subsequent ECRC Dockets (Nos. 080007-EI, 090007-EI, 100007-EI and 110007-EI), the Public Service Commission approved PEF's updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of CAIR, CAMR, CAVR and related regulatory requirements. *In re Environmental Cost Recovery Clause*, Order No. PSC-07-0922-FOF-EI, p. 8 (Nov. 16, 2007), the Commission specifically found that "PEF's updated Integrated Clean Air Compliance Plan represents the most cost-effective alternative for achieving and maintaining compliance with CAIR, CAMR, and CAVR, and related regulatory requirements, and it is reasonable and prudent for PEF to recover prudently incurred costs to implement the plan." *Id.* In its final order, the Commission also directed PEF to file as part of its ECRC true-up testimony "a yearly review of the efficacy of its Plan D and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations." *Id.* The purpose of this report is to provide the required review for 2012.

II. Regulatory Background

The CAIR and CAVR programs required PEF and other utilities to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx). CAIR contemplated emission reductions in incremental phases. Phase I began in 2009 for NOx and in 2010 for SO_2. Phase II was to begin in 2015 for both NOx and SO_2. The CAMR originally required reduction of mercury emissions and installation of mercury monitors. As will be discussed later in this report, CAMR was vacated in early 2008 and on February 16, 2012, EPA published a final Mercury and Air Toxics Standards (MATS) rule.

In March 2006, PEF submitted a report and supporting testimony presenting its integrated plan for complying with the new rules, as well as the process PEF utilized in evaluating alternative plans, to the Commission. The analysis included an examination of the projected emissions associated with several alternative plans and a comparison of economic impacts, in terms of cumulative present value of revenue requirements. PEF's Integrated Clean Air Compliance Plan, designated in the report as Plan D, was found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among five alternative plans.

In June 2007, PEF submitted an updated report and supporting testimony summarizing the status of the Plan and an updated economic analysis incorporating certain plan revisions necessitated by changed circumstances. Consistent with the approach utilized in 2006, PEF performed a quantitative evaluation to compare the ability of the modified alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D, as revised, is PEF's most cost-effective alternative to meet the applicable regulatory requirements. Based on that analysis, the Commission approved PEF's Plan D as reasonable and prudent, and held that PEF should recover the prudently incurred costs of implementing the Plan. Since 2007, the Commission has approved PEF's annual Review of Integrated Clean Air Compliance Plan in the final orders rendered in each annual ECRC docket. See Order No. PSC-11-0553-FOF-EI, at 13-14 (Dec. 7, 2011); Order No. PSC-10-0683-FOF-EI, at 6-7 (Nov. 15, 2010); Order No. PSC-09-0759-FOF-EI, at 18 (Nov. 18, 2009); Order No. 08-0775-FOF-EI, at 11 (Nov. 24, 2008).

A. Status of CAIR and CSAPR

In July 2008, the U.S. Circuit Court of Appeals for the District of Columbia (D.C. Circuit) issued a decision vacating CAIR in its entirety. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). However, the Court subsequently decided to remand CAIR without vacatur, thereby leaving the rule and its compliance obligations in place until EPA revises or replaces CAIR. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008). EPA subsequently adopted CSAPR to replace CAIR by publication in the *Federal Register* in August 2011. 76 Fed. Reg. 48,208 (Aug. 8, 2011).

In Order No. PSC-11-0553-FOF-EI issued in Docket No. 110007-EI on December 7, 2011, the Commission addressed the impact of CSAPR on PEF's recovery of NOx emission allowance costs. Because CSAPR would no longer allow PEF to use NOx allowances previously obtained under CAIR for compliance effective January 1, 2012, the Commission established a regulatory asset to allow PEF to recover the costs of its remaining NOx allowance inventory over a three year amortization period. However, on December 30, 2011, the D.C. Circuit Court of Appeals stayed the CSAPR leaving CAIR in effect until the court completes its review of the new rule. Thus, PEF must continue to maintain its NOx allowance inventory in order to comply with CAIR. Pursuant to the stipulation approved in Order No. PSC-11-0553-

FOF-EI, PEF will continue to expense NOx allowance costs incurred to comply with CAIR based on actual usage consistent with current practice. Any over-recovery of NOx allowance costs resulting from the Commission's establishment of the regulatory asset will be refunded through the normal true-up process in the annual ECRC proceedings.

B. Vacatur of CAMR and Adoption of MATS

In February 2008, the D.C. Circuit vacated the CAMR regulation and rejected EPA's delisting of coal-fired EGUs from the list of emission sources that are subject to Section 112 of the Clean Air Act. *See*, *New Jersey v. EPA*, 517 F. 3d 574 (D.C. Cir. 2008). As a result, in lieu of CAMR, EPA was required to adopt new emissions standards for control of various hazardous air pollutant emissions from coal-fired EGUs. Id. EPA issued its proposed rule to replace CAMR on March 16, 2011, with publication following in the *Federal Register* on May 3, 2011. See 76 Fed. Reg. 24976 (May 3, 2011). On February 16, 2012, EPA published the final rule, which requires compliance by April 16, 2015. The rule establishes new MATS for emissions of various metals and acid gases from both coal and oil-fired EGUs. The new standards apply to all existing coal and oil-fired EGUs, including, potentially, PEF's Crystal River Units 1, 2, 4, and 5, Anclote Units 1 and 2, and Suwannee Units, 1, 2, and 3. Compliance generally must be achieved within three years of EPA's adoption of the standards (i.e., 2015), although the Clean Air Act authorizes permitting authorities to grant one-year compliance extensions in certain circumstances.

. In the 2011 ECRC docket, the Commission recognized that EPA's adoption of the new EGU standards will require PEF to modify its Integrated Clean Air Compliance Plan. Order No. PSC-11-0553-FOF-EI, at 11 (Dec. 7, 2011). Accordingly, consistent with the Commission's expectation that utilities "take steps to control the level of costs that must be incurred for environmental compliance," Order No. PSC-08-0775-FOF-EI, at 7 (Nov. 24, 2008), the Commission approved PEF's request to recover costs incurred by the Company to assess EPA's proposed rule, to prepare comments to the EPA, and to develop compliance strategies within the aggressive regulatory timeframes proposed by EPA. Id. Specifically, the Commission approved recovery of PEF's projected costs of $85,000 for performing emissions testing at Crystal River Units 4 and 5 in 2011, as well as $300,000 of additional costs in 2012 for engineering and other analyses necessary to develop compliance strategies for inclusion in an updated Integrated Clean

Air Compliance Plan. Id. By petition filed on March 29, 2012, PEF requested ECRC recovery of costs associated with the conversion of Anclote Units 1 and 2 to 100% natural gas fired capability as part of PEF's MATS compliance strategy. PEF is still in the process of analyzing compliance strategies for its other coal and oil-fired units.

C. Greenhouse Gas Regulation

In 2007, then-Governor Crist issued Executive Order 07-127 directing FDEP to promulgate regulations requiring reductions in utility carbon dioxide (CO_2) emissions. In addition, the 2008 Florida Legislature enacted legislation authorizing FDEP to adopt rules establishing a cap-and-trade program and requiring FDEP to submit any such rules for legislative review and ratification. To date, however, FDEP has not adopted any cap-and-trade rules. Likewise, although a number of bills that would regulate greenhouse gas (GHG) emissions have been introduced to Congress over the past several years, none have passed both houses. In the meantime, EPA has begun implementation of a regulatory approach to reducing GHG emissions through the Clean Air Act. At this time, however, there are no GHG emission standards applicable to PEF's generating units. Moreover, there are still no retrofit options commercially available to reduce CO_2 emissions from fossil fuel-fired electric generating units such as Crystal River Units 4 and 5, which are the primary focus of PEF's compliance plan. To date, there have been no large-scale commercial carbon capture and storage technology demonstrations on electric utility units. Until numerous technological, regulatory and liability issues are resolved, it will be impossible to determine whether carbon capture and storage would be a technically feasible or cost-effective means of complying with a CO_2 regulatory regime. Moreover, replacing coal-fired generation from Crystal River Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation is not a viable option at this late date, particularly given the fact that PEF has placed in service the Plan D components.

D. Status of Best Available Retrofit Technology (BART)

By October 1, 2013 Crystal River Units 1 and 2 must demonstrate compliance with the terms of the BART permit that was issued by the Florida Department of Environmental Protection in January 2009. PEF is continuing to evaluate potential compliance options for the

Units in light of EPA's recently adopted MATS and other ongoing rulemaking affecting fossil fuel-fired EGUs.

The permit discussed above specifically contains BART requirements for particulate matter. The stay of the CSAPR has left in place the determination that CAIR satisfies BART for SO_2 and NO_x, and EPA has proposed that the CSAPR also satisfies BART for SO_2 and NO_x. However, if the CSAPR is upheld by the court, BART for SO_2 may become an issue for Florida because Florida is not subject to the CSAPR SO_2 program. PEF will continue to monitor closely the status of CAIR and CSAPR and their relationship to BART.

III. PEF's Integrated Clean Air Compliance Plan

PEF's compliance plan (Plan D) meets all currently applicable environmental requirements by striking a balance between reducing emissions, primarily through installation of controls on PEF's largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of the allowance markets to comply with CAIR requirements. The controls installed in accordance with Plan D will continue to be the cornerstone of PEF's compliance strategy with the adoption of MATS and other ongoing regulatory efforts. Specific components of the Plan are summarized below.

1. Flue Gas Desulfurization (FGD) Systems

The most significant component of PEF's Integrated Clean Air Compliance Plan is the installation of FGD systems, also known as wet scrubbers, on Crystal River Units 4 and 5 to comply with SO_2 requirements of CAIR, Title IV of the Clean Air Act, and SO_2 control requirements in PEF's air permits for Crystal River Units 4 and 5. Together with the Selective Catalytic Reduction (SCR) systems discussed below, the FGDs also reduce mercury and other air toxic emissions and, therefore, will be a key component of PEF's MATS compliance strategy. Preliminary analyses indicate that the co-benefits of the FGDs and SCRs reduce mercury emissions by approximately 80%.

2. Selective Catalytic Reduction (SCR) & Other NOx Controls

The primary component of PEF's NOx compliance plan is the installation of Low NOx Burners (LNBs) and SCR systems on Crystal River Units 4 and 5. These controls enable PEF to comply with CAIR and other NOx control requirements included in PEF's air permits for Crystal River Units 4 and 5. As discussed above, the SCRs also will help achieve MATS requirements for mercury. To achieve compliance with CAIR, PEF also has taken strategic advantage of CAIR's cap-and-trade feature by purchasing some annual and ozone season NOx allowances.

3. Additional MATS Compliance Strategies

PEF has determined that the most cost-effective option for PEF's Anclote Units 1 and 2 is to convert the units to fire 100% natural gas rather than install emission controls in order to comply with the new MATS for oil-fired EGUs. As explained in the petition filed March 29, 2012, PEF estimates that the cost of converting the Anclote units to fire 100% natural gas is approximately $79 million.

PEF will utilize the co-benefits of the existing FGD and SCR systems as the primary MATS compliance measure for Crystal River Units 4 and 5, but additional analyses are ongoing to determine whether additional control measures will be necessary for those units. PEF also is in the process of evaluating the most cost-effective MATS compliance options for Crystal Units 1 and 2. PEF expects to complete such analyses in the second quarter of 2012 and will advise the Commission of the results in future filings in the ECRC docket. PEF is also still analyzing the impact of MATS on Suwannee Units 1, 2 and 3.

4. Visibility Requirements

PEF operates four units that are potentially subject to Best Available Retrofit Technology (BART) under CAVR, including Anclote Units 1 and 2 and Crystal River Units 1 and 2. Based on modeling of air emissions from Anclote Units 1 and 2, those units exempted from BART for particulate matter. Because the modeling results for Crystal River Units 1 and 2 showed visibility impacts at or above regulatory threshold levels, PEF obtained a BART permit for particulate matter only for those units. This permit establishes a combined BART particulate matter emission standard for Crystal River Units 1 and 2 which must be achieved by October 1, 2013. As mentioned above, CAIR satisfied BART requirements for NO_x and SO_2 at this time.

However, if CSAPR is upheld by the court, the compliance strategies for SO_2 may need to be evaluated for these units. PEF is continuing to evaluate potential compliance options for Crystal River Units 1 and 2 in light of EPA's recently adopted MATS and other ongoing rulemakings affecting fossil fuel-fired EGUs.

IV. Efficacy of PEF's Plan

A. Project Milestones

PEF completed installation of Plan D's controls on Crystal River Units 4 and 5 as contemplated in prior ECRC filings. Crystal River Units 4 and 5 FGD and SCR projects are now in-service and the targeted environmental benefits have been met or exceeded. Units 4 and 5 SCRs reduce NO_x emissions by approximately 90% and Units 4 and 5 FGDs reduce SO_2 emissions by approximately 97%. The FGDs and SCRs have the combined effect of reducing emissions of mercury and other air toxics which will contribute to PEF's plans to comply with the new MATS.

As noted above, PEF has determined that converting Anclote Units 1 and 2 to fire 100% natural gas is more cost-effective than installing emission controls in order to comply with the new MATS for oil-fired units. PEF anticipates that the conversion of both Anclote Units will be completed by the end of calendar year 2013. PEF is continuing to evaluate MATS compliance options for all of the Crystal River coal-fired units.

B. Projects Costs

Crystal River Units 4 and 5 FGD and SCR projects are now in-service, and the targeted environmental benefits have been met or exceeded. Demobilization and site restoration have been completed, and only minor punch list items remain to be closed out by the end of the first quarter 2012.

As noted above, PEF projects the costs of converting the Anclote units to fire 100% natural gas to be approximately $79 million . PEF will provide costs estimates to the Commission for any additional MATS compliance measures as future decisions are made.

C. Uncertainties

The stay of the CSAPR has left in place the determination that CAIR satisfies BART for SO_2 and NO_x, and EPA has proposed that CSAPR also satisfies BART for SO_2 and NOx. However, if the CSAPR is upheld by the court, BART for SO_2 may become an issue in Florida because Florida is not subject to the CSAPR SO_2 program. PEF will continue to monitor closely the status of CAIR and CSAPR and their relationship to BART.

The outcome of now pending regulation on cooling water intake structures (316(b)) could influence decisions with regard to control technologies to meet new standards. The rule is expected to be issued July 27, 2012 and once its requirements are assessed in conjunction with new air regulation compliance strategies may be altered.

EPA is expected to issue updated Effluent Guidelines for electric power plants in July 2012. These guidelines are expected to affect decisions associated with the treatment of wastewater generated by wet FGDs.

V. Conclusion

PEF has completed installation of the emission controls contemplated in its approved Plan D on time and within budget. The new FGD and SCR systems have enabled PEF to comply with CAIR requirements and will continue to be the cornerstone of PEF's integrated air quality compliance strategy for years to come. PEF is confident that Plan D, along with compliance strategies under development, will enable the Company to achieve and maintain compliance with all applicable regulations, including MATS, in a cost-effective manner. PEF is in the process of evaluating additional compliance options in light of the recent adoption of MATS, the ongoing review of CSAPR, and other regulatory developments affecting fossil fuel-fired electric generating units.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	EXHIBIT	18
PARTY	Progress Energy Florida		
DESCRIPTION	Patricia Q. West (PQW-2), Letter in re FL)		
DATE	NPDES Renewal Program and order filed 2/8/12		

Hopping Green & Sams

Attorneys and Counselors
Writer's Direct Dial No.
(850) 425-2359

February 8, 2012

BY HAND-DELIVERY

REDACTED

Martha Carter Brown, Esquire
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: *In re Environmental Cost Recovery Clause*, Docket No. 120007-EI
Progress Energy Florida's NPDES Renewal Program

Dear Martha:

On behalf of Progress Energy Florida, Inc. (PEF or "Company"), I am writing to advise the Commission and the parties of a recent development related to PEF's previously approved NPDES Renewal Program.

In Order No. PSC-11-0553-FOF-EI issued in Docket No. 110007-EI on December 7, 2011, the Commission approved ECRC recovery of PEF's costs associated with new environmental requirements included in various NPDES renewal permits issued or to be issued for various PEF facilities. At the time, a final NPDES renewal permit had not been issued for PEF's Suwannee River Power Plant. Shortly thereafter, however, on December 14, 2011, the Florida Department of Environmental Protection issued a final NPDES renewal permit and associated Administrative Order for the Suwannee Plant. The Administrative Order includes a new requirement that PEF did not anticipate when it filed its petition requesting approval of the new NPDES Renewal Program in March 2011 or when the Company filed its 2012 cost projections in August 2011. Specifically, the Administrative Order requires PEF to perform a study of copper discharges from the Suwannee Plant and, depending upon the results, may require PEF to perform additional feasibility studies to evaluate options to comply with the copper discharge limit. A copy of the Administrative Order is attached. At this time, PEF expects to incur approximately [redacted] on the initial copper discharge study, beginning in February, 2012. (Because the projected costs constitute confidential business information, PEF is submitting this letter along with a Request for Confidential Classification).

Because the new copper study requirement is within the scope of the previously approved NPDES Renewal Program, PEF will include the costs associated with the new copper discharge study within the Company's estimated/actual projection filings for that program. We also will keep the Commission apprised of any further developments related to the NPDES Renewal Program during the course of this year's ECRC proceedings.

DOCUMENT NUMBER-DATE
00769 FEB-8 12
FPSC-COMMISSION CLERK

In the meantime, please do not hesitate to contact me should you have any questions or comments.

Very truly yours,

HOPPING GREEN & SAMS, P.A.

By: Gary V. Perko

Attorneys for PROGRESS ENERGY FLORIDA, INC.

Enclosure
cc: All counsel of record

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN THE MATTER OF:

Florida Power Corp.
Progress Energy Florida, Inc.
4037 River Road
Live Oak, Florida 32060

Administrative Order No. AC-026-TL

Suwannee River Power Plant
DEP Permit No: FL0000183

ADMINISTRATIVE ORDER

I. STATUTORY AUTHORITY

The Department of Environmental Protection (Department) issues this Administrative Order under the authority of Section 403.088(2)(f), Florida Statutes (F.S.). The Secretary of the Department has delegated this authority to the Director of the Division of Water Resources Management, who issues this order and makes the following findings of fact.

II. FINDINGS OF FACT

1. Florida Power Corp. Progress Energy Florida, Inc. (Permittee) is a "person" as defined under Section 403.031(5), F.S.
2. The Permittee owns and operates a steam electric power generating facility known as Suwannee River Power Plant ("Facility"). The Facility, located at 4037 River Road Live Oak, Suwannee County, Florida 32060, discharges industrial wastewater into waters of the state as defined in Section 403.031(13), F.S.
3. The Permittee has filed a timely application for renewal of NPDES Permit No: FL0000183 (Permit), under Section 403.088(2), F.S.
4. Once-through cooling water discharges to Suwannee River, which is designated a Class III freshwater pursuant to Rule 62-302.400(14), Florida Administrative Code (F.A.C.), and as an Outstanding Florida Water pursuant to Rule 62-302.700(9)(a)(71), F.A.C.
5. Previous sampling has shown that on occasion the once through cooling water concentrations for total recoverable copper exceed the Class III fresh water quality criterion in Rule 62-302.530(23), F.A.C. The Permittee does not add chemical products that contain copper to the wastewater. It is believed that the source of copper is from material used in construction of the once through cooling water system.
6. At issuance of the previous Permit, the Department considered the Facility eligible for a total recoverable copper mixing zone pursuant to Rules 62-4.244 and 62-302.300(10)(b), F.A.C. Hence, the previous Permit included a mixing zone for total recoverable copper. Compliance with the total recoverable copper water quality standard was demonstrated at the edge of the mixing zone.
7. As part of the permit renewal process, the mixing zone size was re-evaluated with a mathematical model using the most recent data available to the Department. The model results predicted that the required size needed to meet the Class III fresh water quality standard at the edge of the mixing zone within the Suwannee River exceeds the maximum size allowed under Rule 62-4.244, F.A.C. Hence, the Department is unable to approve the continuance of the total recoverable copper mixing zone.
8. The Department finds that:

a. There is no present, reasonable, alternative means of disposing of the waste other than by discharging it into the waters of the state;

b. The granting of an operation permit will be in the public interest; and,

c. The discharge will not be unreasonably destructive to the quality of the receiving water.

9. This order and associated wastewater Permit FL0000183 constitute the Department's authorization to discharge pollutants to waters of the state under the NPDES program, and its determination that the Facility is in compliance with Section 403.088, F.S. This order includes an implementation schedule.

III. ORDER

Based on the foregoing findings of fact,

IT IS ORDERED,

10. No later than 180 days after the effective date of this Order, the Permittee shall prepare and submit for the Department's review a plan of study (POS) and schedule for the identification and evaluation of potential copper sources within the Facility and collection of paired intake and discharge data sets that pairs total recoverable and dissolved copper in the Suwannee. The POS shall be designed and implemented to demonstrate that the discharge from the Facility meets the discharge limitations in Part I.A.1. of the Permit. The results of the evaluation shall be submitted in a report (Report) to the Department for review and approval no later than 60 days after the approved POS completion date.

11. If the Report fails to demonstrate that the effluent discharge from the Facility meets the total recoverable copper discharge limitation in Part I.A.1. of the Permit, the Permittee shall prepare a feasibility study (Study) for the evaluation of on-site recycling and treatment options to achieve the discharge limitation(s). The Study shall be submitted to the Department for review and approval no later than 60 days after the approved POS completion date.

12. The Permittee may petition the Department for an appropriate moderating provision or other available relief provided for under Chapters 120 or 403, F.S., and the rules promulgated thereunder. Any petition for a moderating provision shall include an evaluation of all potential on-site reuse and treatment options and the feasibility of each, and sampling of the sediment, using appropriate analytical methods, in and around the outfall for the effluent discharge designated as Outfall D-001 in the Permit. Any such petition shall be submitted no later than 60 days after receipt of Department approval of a Report and shall demonstrate the need for a less stringent discharge limitation than contained in Part I.A.1. of the Permit in accordance with Rule 62-620.620(3), F.A.C.

13. No later than 48 months after the effective date of this Order, the Permittee shall either comply with the total recoverable copper discharge limitations in Part I.A.1. of the Permit, or with an alternative discharge limitation based on the Reports and Study as approved by the Department.

14. Until compliance with the copper limitations in Part I.A.1. of the Permit is achieved as required in III.13. of this Order, the Permittee shall comply with an interim total recoverable copper limitation of 34.0 ug/L at the discharge from Outfalls D-001.

15. The Permittee shall maintain and operate its facilities in compliance with all other conditions of the Permit.

16. This order may be modified through revisions as set forth in Chapter 62-620, F.A.C.

17. Unless otherwise specified herein, reports or other information required by this order shall be sent to: Industrial Wastewater Section, ATTN: Mail Station 3545, Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, with a copy sent to: Industrial Wastewater Section, Department of Environmental Protection, Northeast District, 7825 Baymeadows Way, Suite B-200, Jacksonville, Florida 32256-7590.

18. This order does not operate as a permit under Section 403.088, F.S. This order shall be incorporated by reference into NPDES Permit No. FL0000183, which shall require compliance by the Permittee with the requirements of this order.

19. Failure to comply with the requirements of this order shall constitute a violation of this order and Permit No. FL0000183, and may subject the Permittee to penalties as provided in Section 403.161, F.S.

20. This order is final when filed with the clerk of the Department, and the Permittee then shall implement this order unless a petition for an administrative proceeding (hearing) is filed in accordance with the notice set forth in the following Section.

21. If any event occurs that causes delay or the reasonable likelihood of delay, in complying with the requirements of this order, the Permittee shall have the burden of demonstrating that the delay was or will be caused by circumstances beyond the reasonable control of the Permittee and could not have been or cannot be overcome by the Permittee's due diligence. Economic circumstances shall not be considered circumstances beyond the reasonable control of the Permittee, nor shall the failure of a contractor, subcontractor, materialman or other agent (collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines be a cause beyond the control of the Permittee, unless the cause of the contractor's late performance was also beyond the contractor's control. Delays in final agency action on an application for a relief mechanism are eligible for consideration under this paragraph, provided that none of those delays were a result of late submission by the Permittee. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, the Permittee shall notify the Department orally at the Department's Northeast District office, (904)-807-3371, within 24 hours or by the next working day and shall, within seven calendar days of oral notification to the Department, notify the Department in writing at Northeast District office, 7825 Baymeadows Way, Suite B-200, Jacksonville, Florida 32256-7590 of the anticipated length and cause of the delay, the measures taken or to be taken to prevent or minimize the delay and the timetable by which Facility intends to implement these measures. If the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of the Permittee, the time for performance hereunder shall be extended for a period equal to the delay resulting from such circumstances.

IV. NOTICE OF RIGHTS

A person whose substantial interests are affected by the Department's decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 of the F.S. The petition must contain the information set forth below and must be filed (received by the clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

Petitions by the applicant or any of the parties listed below must be filed within fourteen days of receipt of this written notice. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the notice or within fourteen days of receipt of the written notice, whichever occurs first.

Under Section 120.60(3), F.S., however, any person who has asked the Department for notice of agency action may file a petition within fourteen days of receipt of such notice, regardless of the date of publication.

The petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S.. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the

(c) A statement of how each petitioner's substantial interests are affected by the Department action;

(d) A statement of the material facts disputed by the petitioner, if any;

(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department action;

(f) A statement of which rules or statutes the petitioner contends require reversal or modification of the Department action; and

(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take.

A petition that does not dispute the material facts on which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation under Section 120.573, F.S., is not available for this proceeding.

This action is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above. Upon the timely filing of a petition this order will not be effective until further order of the Department.

Any party to the order has the right to seek judicial review of the order under Section 120.68, F.S., by the filing of a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department in the Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000; and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when the final order is filed with the Clerk of the Department.

DONE AND ORDERED on this 14th day of December, 2011 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mark F. Thomasson, P.E.
Director
Division of Water Resource Management

CLERK STAMP

FILED AND ACKNOWLEDGED on this date, under Section 120.52(7) of the Florida Statutes, with the designated Department Clerk, receipt of which is acknowledged.

Shirley Shields
Clerk

12-14-2011
Date

Copies furnished to Permit Distribution List

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	**EXHIBIT**	19
PARTY	Progress Energy Florida		
DESCRIPTION	Patricia Q. West (PQW-3), Verified Petition		
DATE	modifying scope Env. Prog. PEF filed 3/20/12		

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	DOCKET NO. 120007-EI
	FILED: March 29, 2012

PROGRESS ENERGY FLORIDA, INC.'S PETITION TO MODIFY SCOPE OF EXISTING ENVIRONMENTAL PROGRAM

Progress Energy Florida, Inc. ("PEF" or "Company"), pursuant to Section 366.8255, Florida Statutes, and Florida Public Service Commission Order Nos. PSC-94-0044-FOF-EI and PSC-99-2513-FOF-EI, hereby petitions the Commission to modify the scope of its previously approved Integrated Clean Air Compliance Program to encompass additional activities such that the costs associated with such activities may be recovered through the Environmental Cost Recovery Clause ("ECRC"). In support, PEF states:

1. Petitioner. PEF is a public utility subject to the regulatory jurisdiction of the Commission under Chapter 366, Florida Statutes. The Company's principal offices are located at 299 First Avenue North, St. Petersburg, Florida.

2. Service. All notices, pleadings and other communications required to be served on the petitioner should be directed to:

Gary V. Perko
Hopping Green & Sams, P.A.
119 S. Monroe St., Suite 300
P.O. Box 6526 (32314)
Tallahassee, FL 32301
Tel. 850.222.7500
Fax. 850.224.8551
gperko@hgslaw.com

John T. Burnett
Dianne M. Triplett
Progress Energy Services Co., LLC
299 First Avenue North, PEF-151
St. Petersburg, FL 33701
john.burnett@pgnmail.com
dianne.triplett@pgnmail.com

3. Cost Recovery Eligibility. As further discussed below, the U.S. Environmental Protection Agency ("EPA") recently issued new air emission standards for coal and oil-fired electric generating units ("EGUs"). As a result of the new regulations, PEF will incur costs for

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new environmental compliance activities related to its previously approved Integrated Clean Air Compliance Program. As detailed below, the new compliance activities meet the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI in that:

(a) all expenditures will be prudently incurred after April 13, 1993;

(b) the activities are legally required to comply with a governmentally imposed environmental regulation that was created, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and

(c) none of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

The information provided below for each program satisfies the minimum filing requirements established in Part VI of Order No. PSC-99-2513-FOF-EI.

4. PEF's Approved Integrated Clean Air Compliance Plan. In the 2007 ECRC Docket, the Commission approved PEF's Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR), and related regulatory requirements. See Order No. PSC-07-0922-FOF-EI, at 8 (Nov. 16, 2007). In each subsequent ECRC docket, the Commission approved PEF's annual review of the Integrated Clean Air Compliance Plan, concluding that the Plan remains the most cost-effective alternative for achieving and maintaining compliance with the applicable air quality regulatory requirements. See Order No. PSC-11-0553-FOF-EI, at 13-14 (Dec. 7, 2011); Order No. PSC-10-0683-FOF-EI, at 6-7 (Nov. 15, 2010); Order No. PSC-09-0759-FOF-EI, at 18 (Nov. 18, 2009); Order No. 08-0775-FOF-EI, at 11 (Nov. 24, 2008).

5. New Environmental Requirements. As the Commission is aware, in February 2008, the U.S Circuit Court of Appeals for the District of Columbia vacated the CAMR regulation and rejected EPA's delisting of coal-fired EGUs from the list of emission sources that are subject to Section 112 of the Clean Air Act. See Order No. PSC-09-0759-FOF-EI, at pp. 15, 18 (Nov. 18, 2009). As a result, in lieu of CAMR, the EPA was required to adopt new emissions standards for control of hazardous air pollutant emissions from coal-fired EGUs. Id. The EPA issued its proposed rule to replace CAMR on March 16, 2011, with publication following in the *Federal Register* on May 3, 2011. See 76 Fed. Reg. 24976 (May 3, 2011). Following the public comment period on the proposed rule, the EPA released the final rule on December 21, 2011, with publication in the *Federal Register* following on February 16, 2012. See 77 Fed. Reg. 9304 (Feb. 26, 2012).

6. The final rule establishes new Mercury and Air Toxics Standards ("MATS") for emissions of various metals and acid gases from both coal and oil-fired EGUs, including, potentially, units at PEF's Crystal River Plant (Units 1, 2, 4, and 5), Anclote Plant (Units 1 and 2), and Suwannee Plant (Units 1, 2, and 3). The Clean Air Act generally provides a 3-year time frame to comply with MATS, although the permitting agency has the authority to add one year, and the President has the authority to add up to two additional years.

7. New Compliance Activities for Anclote Units 1 and 2. Anclote Units 1 and 2 currently have a maximum summer rating of 500MW and 510 MW, respectively. The current natural gas firing capability for each unit is limited to 40% of the total heat input. Because the balance of the heat input is from heavy fuel oil, the units would be subject to the new MATS for oil-fired EGUs. However, PEF has determined that the most cost-effective compliance option

for PEF's Anclote Units 1 and 2 is to convert the units to fire 100% natural gas and thereby remove the units from the scope of the new MATS regulation.

8. PEF considered two compliance alternatives for the Anclote units. The first option would achieve compliance with the new MATS through use of emissions controls, specifically low NOx burners and an electrostatic precipitator ("ESP"). The second option would achieve compliance through conversion of the units to operation on natural gas as the single fuel.[1] After estimating the capital costs and unit performance implications of the two options, PEF determined that the natural gas option has economic benefits in terms of both capital costs and fuel savings. Based on conservative cost estimates associated with the emissions controls that would be necessary to achieve oil-fired compliance, the capital cost of the gas conversion is expected to be at least $12 million less than the capital costs for the emissions controls. PEF also estimated the fuel cost differential of the two options, primarily to ensure that implementation of the gas conversion would not cause an increase in system fuel costs. The analysis demonstrates that the net impact on system cost is positive (savings), indicating an additional benefit.

9. Preliminary studies indicate that the addition of three levels of fuel gas burners in combination with the existing natural gas burners will be required to provide full output on 100% natural gas. Thermal analysis of the boiler for operation on 100% natural gas indicates that a portion of the lower horizontal superheater will need to be removed to limit heat absorption and manage superheater tube metal temperatures. In addition, the gas supply line measurement and regulation ("M&R") facilities will require upgrades to support operation on 100% gas. Finally,

[1] A third option, discontinuation of heavy fuel oil use without conversion, was rejected because of its negative effect on fleet capacity and the resulting requirement to purchase or construct additional generation to meet reserve margin and operational requirements, including potential system reliability impacts

the finishing horizontal superheater for each unit will require metallurgy upgrades to accommodate the peak temperatures resultant from the gas conversion. While the additional burners and the replacement superheater form the majority of the boiler work required, other areas of the boiler and its control system may require configuration changes to complete the conversion based on ongoing boiler engineering analysis and condition assessment.

10. Cost Estimates. PEF expects to incur approximately $79 million in total capital costs to convert the Anclote units to fire 100% natural gas. PEF expects to incur approximately $26 million in 2012 and the remainder (approximately $53 million) in 2013. PEF currently anticipates that both converted units will be placed in service by the end of 2013.

11. Prudence of Expenditures. As discussed above, in order to ensure that the costs incurred to comply with the new regulation are prudent and reasonable, PEF performed a comparative analysis and determined that the natural gas conversion project is the most cost-effective compliance option for Anclote Units 1 and 2. To ensure that actual expenditures are reasonable, PEF will competitively bid procurement of major boiler equipment to boiler original equipment manufacturers (OEMs).

12. No Base Rates Recovery of Program Costs. None of the costs for which PEF seeks recovery by this Petition were included in the MFRs that PEF filed in its last ratemaking proceeding in Docket No. 090079-EI. Therefore, the costs are not recovered in PEF's base rates.

13. No Change in Current ECRC Factors. PEF does not seek to change the ECRC factors currently in effect for 2012. The Company proposes to include in its estimated true-up filing for 2012 all program costs incurred subsequent to the filing of this petition through the end of 2012. PEF expects that all of these costs will be subject to audit by the Commission and that

the appropriate allocation of program costs to rate classes will be addressed in connection with subsequent filings.

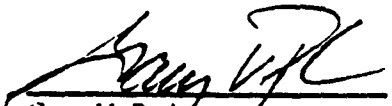
14. No Material Facts in Dispute. PEF is not aware of any dispute regarding any of the material facts contained in this petition. The information provided in this petition demonstrates that the programs for which approval is requested meets the requirements of Section 366.8255 and applicable Commission orders for recovery through the ECRC.

WHEREFORE, PEF requests that the Commission modify the scope of PEF's previously approved Integrated Clean Air Compliance Program to encompass additional activities associated with the Anclote MATS compliance project described above, such that the costs associated with such activities reasonably may be recovered through the ECRC.

RESPECTFULLY SUBMITTED this 29th day of March, 2012.

John T. Burnett
Associate General Counsel
Dianne M. Triplett
Associate General Counsel
PROGRESS ENERGY SERVICE COMPANY, LLC
Post Office Box 14042
St. Petersburg, FL 33733-4042
PEF-151

HOPPING GREEN & SAMS, P.A.

By: 
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gperko@hgslaw.com
Tel.: (850) 425-2359
Fax: (850) 224-8551

Attorneys for PROGRESS ENERGY FLORIDA, INC.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished to all counsel of record and interested parties as listed below via regular U.S. mail this 29th day of March, 2012.

Martha Carter Brown, Esquire
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

J. Jeffry Wahlen, Esquire
James D. Beasley, Esquire
Ausley Law Firm
Post Office Box 391
Tallahassee, Florida 32302

J.R. Kelly, Esquire
Patricia Christensen, Esquire
Charles J. Rehwinkel, Esquire
Office of Public Counsel
c/o The Florida Legislature
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Tallahassee, Florida 32399

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Tallahassee, Florida 32301

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Regulatory Affairs
Tampa Electric Company
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Tampa, Florida 33601-0111

R. Alexander Glenn, Esquire
John T. Burnett, Esquire
Dianne M. Triplett, Esquire
Progress Energy Service Company, LLC
Post Office Box 14042
St. Petersburg, Florida 33733

Attorney

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	**EXHIBIT**	20
PARTY	Progress Energy Florida		
DESCRIPTION	Patricia Q. West (PQW- 4), Letter in re FL		
DATE	integrated Clean Air Complinace Plan fld 5/14/12		

Hopping Green & Sams

Attorneys and Counselors

Writer's Direct Dial No.
(850) 425-2359

May 14, 2012

Charles W. Murphy, Esquire
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: *In re Environmental Cost Recovery Clause*, Docket No. 120007-EI
Progress Energy Florida's Integrated Clean Air Compliance Plan

Dear Mr. Murphy:

On behalf of Progress Energy Florida, Inc. (PEF or "Company"), I am writing to update the Commission and the parties regarding PEF's ongoing integrated clean air compliance planning activities. As discussed below, PEF expects to incur additional costs, beyond those previously anticipated, for emissions monitoring and modeling activities associated with PEF's Integrated Clean Air Compliance Plan.

In Order No. PSC-11-0553-FOF-EI issued in Docket No. 110007-EI on December 7 2011, the Commission approved ECRC recovery of PEF's costs associated with emissions testing and related analyses necessary to develop PEF's strategy for achieving compliance with new hazardous air pollutant standards (now known as "MATS") at Crystal River Units 4 and 5. At that time, PEF expected to incur approximately $300,000 in costs for emissions testing needed to assess mercury, particulate and acid gas emissions from the Crystal River units. Based on a review of the final MATS rule issued on December 21, 2011, as well as the results of initial emissions testing, PEF has determined that more detailed emissions testing and continuous monitoring is required to enable PEF to adequately assess potential mercury control strategies. Among other things, PEF plans to install mercury monitors that will enable the Company to develop a longer-term assessment of mercury emissions under a variety of operating conditions and control options. This longer-term assessment is necessary to ensure that potential control options can consistently achieve compliance on a 30-day rolling average basis as required under the final MATS rule.

In addition, as noted in PEF's annual review of its Integrated Clean Air Compliance Plan (filed as Exhibit PQW-1 on April 2, 2012), Best Available Retrofit Technology ("BART") requirements for sulfur dioxide ("SO_2") could become an issue for PEF units depending upon the results of ongoing litigation over EPA's Cross-State Air Pollution Rule ("CSAPR"). EPA is now requiring Florida to amend its State Implementation Plan to facilitate implementation of BART requirements once the CSAPR litigation is resolved.

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FPSC-COMMISSION CLERK

As a result, PEF will be working with the Florida Department of Environmental Protection to perform air quality modeling necessary to determine whether emissions from PEF units impact visibility conditions so as to trigger BART requirements for SO_2.

Because the additional emissions monitoring and modeling activities discussed above are within the scope of PEF's previously approved Integrated Clean Air Compliance Plan, PEF will include the costs associated with these activities within the Company's estimated/actual projection filings for that program. We also will keep the Commission apprised of any further developments related to the Integrated Clean Air Compliance Plan during the course of this year's ECRC proceedings.

In the meantime, please do not hesitate to contact me should you have any questions or comments.

Very truly yours,

HOPPING GREEN & SAMS, P.A.

By: Gary V. Perko

Attorneys for PROGRESS ENERGY FLORIDA, INC.

Enclosure
cc: All counsel of record

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic (*) or regular U.S. Mail this 11th day of May, 2012 to all parties of record as indicated below.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 21
PARTY Progress Energy Florida
DESCRIPTION Patricia Q. West (PQW-)Form 42-5P, 3-10 of 20,
DATE 9-18 of 20, and 20 of 20. (TGF-3R)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
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Project Title: **Pipeline Integrity Management, Review/Update Plan and Risk Assessments**
Project No. 3

Project Description:
The U.S. Department of Transportation ("USDOT") Regulation 49 CFR Part 195, as amended effective February 15, 2002 and the new regulation published at 67 Federal Register 2136 on January 16, 2002, requires PEF to implement a Pipeline Integrity Management Program. Prior to the February 15, 2002 amendments, the USDOT's pipeline integrity management regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on February 15, 2002 extended the requirements for implementing integrity management to operators who have less than 500 miles of regulated pipelines. As such, PEF must improve the integrity of pipeline systems in order to protect public safety and the environment, as well as comply with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis, and follow up with remedial, preventative, and mitigative actions.

Effective February 2010, amendments to 49 CFR 195 were finalized to improve opportunities to reduce risk through more effective control of pipelines. Compliance with these amendments will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management. On June 16, 2011, USDOT published in the Federal Register (Vol. 76, 35130-35136), a final rule effective August 15, 2011 that expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This final rule amends the program implementation deadlines for different procedures to no later than October 21, 2011, and August 1, 2012.

PEF owns one hazardous liquid pipeline that is subject to the new regulation and must comply with the new requirements for the Bartow/Anclote 14-inch hot oil pipeline, extending 33.3 miles from the Company's Bartow Plant north of St. Petersburg to the Anclote Plant in Holiday.

Project Accomplishments:

PEF has developed pipeline control room management procedures and trained Pipeline Terminal Operators on said procedures. PEF has also procured a pipeline operations simulator to be used to train Pipeline Terminal Operators. PEF completed the second In Line Inspection (Smart Pig) in late 2009. Smart pig data validation, corrosion rate calculations, anomaly ranking, repair planning, inspection interval determination, risk analysis updates, spill consequence updates, data alignment, and biennial review activities are ongoing. Since mid-2010 PEF has completed repairs and validations based on the Smart Pig findings. These findings required completion of three immediate repairs, one 60-Day repair, one 180-Day repair, and six other repairs along with several risk reduction projects. Risk reduction coordination is ongoing for third party projects at U.S. Highway 19 and Haines Bayshore Road, 9th Street and Gandy Boulevard, 118th Avenue, Progress Energy Trail, and Spruce Street. In June 2011, a sinkhole opened up in close proximity to the pipeline. Geotechnical testing was undertaken along a two mile length of the pipeline that is located in an active sinkhole area. Two large voids were found under the pipeline that required injection grouting to prevent collapse.

Project Fiscal Expenditures:

January 1, 2012 to December 31, 2012: O&M project expenditures are estimated to be approximately $0.1 million lower than originally projected .

Project Progress Summary:
Ongoing Smart Pig anomaly evaluation, data validation, corrosion rate calculations, repair ranking, repair implementation, program biennial review activities, and third party project coordination continue. This compliance work will continue through the end of 2012. 2013 O&M costs are to comply with the Pipeline Integrity Management regulations (49 CFR Part 195). These costs include general program management and oversight of the performance of program activities.

Project Projections:
For 2013 O&M expenditures are expected to be approximately $0.6M. There are no expected capital expenditures.

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Project Title: **Above Ground Storage Tank Secondary Containment**
Project No. 4

Project Description:
Florida Department of Environmental Protection Rule 62-761.510(3) states that the Company is required to make improvements to many of its above ground petroleum storage tanks in order to comply with those provisions. Subsection (d) of that rule requires all internally lined single bottom above ground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. Rule 62-761.500(1)(e) also requires that dike field area containment for pre-1998 tanks be upgraded, if needed, to comply with the requirement.

Project Accomplishments:
PEF has completed work at: DeBary 1, Turner 7, Turner 8, Higgins 1, and Bartow 6 as well as Turner P-1 and P-2 piping work. DeBary 2 was completed in 2011.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: There are no projected O&M project expenditures for this project in 2012. Capital expenditures are projected to be approximately $5,000 to finalize the project.

Project Progress Summary:
PEF will continually evaluate its compliance program, including project prioritization, schedule, and technology applications.

Project Projections:
PEF projects no expenditures in 2013 related to this program.

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Project Title: **Integrated Clean Air Compliance Plan - SO_2 and NOx Emissions Allowances**
Project No. 5

Project Description:
In accordance with the Acid Raint Program inTitle IV of the Clean Air Act, CFR 40 Part 73 and Part 76, and Florida Administrative Code Rule 62-214 and the Clean Air Interstate Rule (CAIR), PEF manages sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions allowance inventories for the purpose of offsetting SO2 and NOx emission. On 7/6/11, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace CAIR. CSAPR would significantly alter the SO2 and NOx allowance programs. Under CAIR, Florida is required to comply with annual SO2 and NOx emission requirements and seasonal requirements regulating NOx emissions during the ozone season. Under CSAPR, Florida would no longer included in the group of states required to comply with annual emissions requirements; it would only be covered by the seasonal ozone requirements. However, on 8/21/12, the U.S. Court of Appeals for the District of Columbia vacated CSAPR, leaving CAIR in effect until EPA adopts a valid replacement. Further discussion of CSAPR is included in the testimony of Patricia Q. West.

Project Accomplishments:

For purposes of compliance with an affected unit's sulfur dioxide (SO_2) and nitrogen oxides (NOx) emissions requirements under the Acid Rain Program, air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases of SO_2 and NO_X emissions allowances as well as auctions and transfers of SO_2 emissions allowances.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project expenditures are estimated to be approximately $3 million lower than originally projected. This variance is driven by lower actual NOx allowance expense due to usage than the estimated 2012 NOx allowance expense resulting from the 3yr amortization calculation presented in Docket No. 110007-EI.

Project Progress Summary:
PEF continually evaluates the status of CSARP and CAIR rules to maximize the cost effectiveness of its compliance strategy.

Project Projections:
For 2013 SO_2 expenditures are expected to be approximately $0.3 million and NOx expenses are expected to be approximately $3.1 million.

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Project Title: **Phase II Cooling Water Intake**
Project No. 6

Project Description:

Section 316(b) of the Federal Clean Water Act, requires that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." 33 U.S.C. Section 1326. In the past, EPA and the state regulatory agency implemented Section 316(b) on a case-by-case basis. In the new Phase II rules, EPA has established "national performance standards" for determining compliance with Section 316(b) at certain existing electric generating facilities. See 40 CFR 125.94(b). The process of compliance involves planning and scheduling efforts, conducting certain biological studies, and evaluation of options for compliance. These compliance options involve engineering measures, operational measures, restorative measures and/or cost assessment measures. See generally 40 CFR 125.94 and 125.95. The EPA is expected to final new Phase II rules in June 2013.

Project Accomplishments:

PEF facilities subject to EPA's new Phase II rules include Anclote, Bartow, Crystal River and Suwannee plants. Early in 2004 PEF requested competitive bids for an environmental consultant to support the development of a Compliance Strategy and Implementation Plan (CSIP); that contract was secured and the CSIP is now complete. The consultant completed a Proposals for Information Collection (PICs) for Anclote & Bartow, Crystal River, and Suwannee and they have been submitted and approved by the FDEP.

Project Fiscal Expenditures:

January 1, 2012 - December 31, 2012: Due to a federal courts vacatur of the Phase II rules, the estimated project O&M expenditures for the period January 2012 through December 2012 are projected to be $0.

Project Progress Summary:

As a result of the July 17, 2012 second amendment to the settlement agreement among the U.S. Environmental Protection Agency (EPA) and plaintiffs, EPA is expected to issue a final rule establishing cooling water intake standards pursuant to Section 316(b) of the Clean Water Act rule in June 2013. The proposed rule would establish standards for impingement mortality that can be achieved in either one of two ways: 1) modify traveling intake screens with fish collection and return systems that demonstrate that 88% of the fish collected will survive the process or 2) reduce the intake flow velocity to 0.5 feet per second. The proposed 316(b) rules would establish that state permitting authorities (FDEP in Florida) determine requirements for entrainment mortality on a case-by-case, site specific basis. The permittee must collect data, conduct studies and submit information that would be used by the state permitting authorities to make its decision. Permittees would also be required to include an evaluation of a closed-cycle, re-circulating cooling system (cooling towers) retrofit as part of their entrainment studies. PEF is assessing several options that may be required to comply with the rule. The options under consideration may change once the final rule is issued and its impacts better understood, therefore the exact costs that PEF will incur under 316(b) cannot be predicted.

Project Projections:
For the period January 2013 through December 2013 PEF does not expect any expenditures.

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Description and Progress Report for
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Project Title: **Integrated Clean Air Compliance Plan - Clean Air Interstate Rule (CAIR)**
Project Nos. (7.2, 7.3, & 7.4)

Project Description:
Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant new restrictions on emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") from power plants in 28 eastern states, including Florida, and the District of Columbia. The CAIR rule apportions region-wide SO_2 and NOx emission reduction requirements to the individual states, and further required each affected state to revise its State Implementation Plans (SIP) to include measures necessary to achieve its emission reduction budget within prescribed deadlines.

Project Accomplishments:
During 2012, the project team focused on completing the installation of the Hydrated Lime Injection System.

Project Fiscal Expenditures:
January 1, 2013 - December 31, 2013: PEF's capital expenditures for CAIR will be approximately $23.2 million lower than PEF's 2012 Projection filing. The difference is primarily attributable to the completion of the Hydrated Lime and SO3 probes projects in 2012.

Project Progress Summary:

For FGD Blowdown treatment, a wastewater treatment study is currenltly being performed by CH2MHill; the study is estimated to complete in October 2012. The study is being conducted in accordance with Conditions of Certification Modification P which requires the submission of an evaluation of alternative(s) to manage FGD blowdown.

Project Projections:
PEF expects approximately $27.9 million in O&M expenses and approximately $4.7 million in capital expenditures for this program.

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Project Title: **Integrated Clean Air Compliance Plan - Best Available Retrofit Technology (BART)**
Project No. 7.5

Project Description:
On May 25, 2012, the Environmental Protection Agency (EPA) proposed a partial disapproval of Florida's proposed Regional Haze State Implementation Plan (SIP) because the proposed SIP relies on CAIR to satisfy BART requirements for SO2 and NOx emissions. Although CAIR remains in effect while litigation against the Cross State Air Pollution Rule (CSAPR) proceeds, the EPA is requiring states to incorporate the Cross State Air Pollution Rule (CSAPR) in place of CAIR in their Regional Haze SIPs. PEF has been working with the FDEP to develop a specific BART and Reasonable Progress permits for affected units that will be incorporated into Florida's revised SIP submittal, which is due to be submitted to EPA by July 31, 2012.

Project Accomplishments:
Performed required emissions modeling and associated BART analysis for Crystal River Units 1 & 2 and Anclote plants, developed and submitted Reasonable Progress evaluation for Crystal River Units 4 & 5, developed and submitted necessary BART Implementation Plans and air construction permit applications needed in support of the Florida Department of Environmental Protection's (FDEP) ongoing work to amend its State Implementation Plan as directed by the EPA.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: PEF expects O&M project expenditures for the year of $27,000.

Project Progress Summary:
Performed required emissions modeling and associated BART analysis for Crystal River Units 1 & 2 and Anclote plants, developed and submitted Reasonable Progress evaluation for Crystal River Units 4 & 5, developed and submitted necessary BART Implementation Plans and air construction permit applications needed in support of the FDEP ongoing work to amend its State Implementation Plan as directed by the EPA.

Project Projections:
For the period January 2013 through December 2013 PEF expects $16,000 of O&M expenditures.

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Project Title: **Arsenic Groundwater Standard**
Project No. 8

Project Description:
On January 22, 2001, the U.S. Environmental Protection Agency (USEPA) adopted a new maximum contaminant level (MCL) for arsenic in drinking water, replacing the previous standard of 0.050 mg/L (50ppb) with a new MCL of 0.010 mg/L (10ppb). Effective January 1, 2005, FDEP established the USEPA MCL as Florida's drinking water standard. See Rule 62-550, F.A.C. The new standard has implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous PEF sites.

Project Accomplishments:
Routine quarterly sampling of existing monitoring wells continues as required by the Industrial Wastewater Permit No. FLA016960. A groundwater plan of study (POS), involving the investigation of sources of arsenic, will continue through 2012.

Project Fiscal Expenditures:
January 1, 2012 - December 31, 2012: PEF is not expecting to spend any dollars on this project in 2012.

Project Progress Summary:
PEF will finsh and submit results of the POS during the first quarter, 2013. Next steps will likely involve submittal of a parameter exemption petition to FDEP.

Project Projections:
PEF expects approximately $31,000 in expenditures for this project in 2013 to finish the groundwater POS and to complete a parameter exemption petition submittal.

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Description and Progress Report for
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Project Title: **Underground Storage Tanks**
Project No. 10

Project Description:
FDEP rules require that underground pollutant storage tanks and small diameter piping be upgraded with secondary containment by December 31, 2009. See Rule 62-761.510(5), F.A.C. PEF has identified four tanks that must comply with this rule: two at the Crystal River power plant and two at the Bartow power plant.

Project Accomplishments:
Work on Crystal River and Bartow USTs was completed in the fourth quarter 2006.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: $0 was projected to be spent in 2012.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Description and Progress Report for
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Project Title: **Modular Cooling Towers**
Project No. 11

Project Description:
The project involves installation and operation of modular cooling towers in the summer months to minimize "de-rates" of PEF's Crystal River Units 1 and 2 necessary to comply with the NPDES permit limit for the temperature of cooling water discharged from the units.

Project Accomplishments:
Vendors of modular cooling towers were evaluated regarding cost of installation and operation. The Florida Department of Environmental Protection reviewed the project and approved operation. A vendor was selected and the towers were installed during the second quarter of 2006.

Project Fiscal Expenditures:

January 1, 2012 to December 31, 2012: Project O&M costs are $0.9 million higher than projected.

Project Progress Summary:
Modular cooling towers began operation in June 2006 and have successfully minimized de-rates of Units 1 and 2. Towers were removed during the first half of 2012. This project is complete.

Project Projections:
PEF projects no expenditures in 2013 related to this program.

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Project Title: **Crystal River Thermal Discharge Compliance Project**
Project No. 11.1

Project Description:
This project will evaluate and implement the best long term solution to maintain compliance with the thermal discharge limit in FDEP industrial wastewater permit for Crystal River 1, 2 & 3 that is currently being addressed in the short term by the Modular Cooling Towers approved in Docket No. 060162- EI for ECRC recovery.

Project Accomplishments:
The Study phase of the project is complete. The recommendation is to replace the modular cooling towers in coordination with the cooling solution for the CR3 Extended Power Uprate (EPU) discharge canal cooling solution. The new cooling tower associated with the CR3 EPU will be sized to mitigate both the increased temperatures from the EPU as well as serve to replace the modular cooling towers, which were removed in 2012. This project will be impacted by both the final form of new environmental regulations and the repair plan and timing of completing the Crystal River Unit 3 delamination work.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project costs are $0.6 million higher than projected; PEF did not file estimated costs for this project in the 2012 Projection filing.

Project Progress Summary:
The design contract for the CR3 EPU cooling tower has been awarded and a cooling tower supplier has been selected.

Project Projections:
Cost estimates for this project will be impacted by both the final form of new environmental regulations, and the repair plan and timing of completing Crystal River 3 delamination work. Current estimates are presented in schedule 42-4P p 14 of 17.

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Project Title: **Integrated Clean Air Compliance Plan - Greenhouse Gas Inventory and Reporting**
Project No. 12

Project Description:
The Greenhouse Gas (GHG) Inventory and Reporting Program was created in response to Chapter 2008-277, Florida Laws, which established the Florida Climate Protection Act, to be codified at section 403.44, Florida Statutes. Among other things, this legislation authorizes FDEP to establish a cap and trade program to GHG emissions from electric utilities. Utilities subject to the program, including PEF, will be required to use The Climate Registry for purposes of GHG emission registration and reporting.

The requirement to report to The Climate Registry was repealed during the 2010 legislative session; however, EPA's GHG Reporting Rule (40 CFR 98) does require that PEF submit 2010 GHG data to the EPA by March 31, 2011.

Project Accomplishments:
In 2009, Progress Energy joined The Climate Registry and submitted the 2008 GHG inventory data. The 2009 data was submitted during the third quarter of 2010. Both 2008 and 2009 data was validated by a third party as required by The Climate Registry. The 2010 GHG inventory data will be submitted to EPA by September 30, 2011 and validation by a third party is not a requirement.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: $0 was projected to be spent in 2012.

Project Progress Summary:
The 2010 GHG inventory data was submitted to EPA on September 30, 2011.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Description and Progress Report for
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Project Title: **Mercury Total Daily Maximum Loads Monitoring (TMDL)**
Project No. 13

Project Description:
Section 303(d) of the federal Clean Water Act requires each state to identify state waters not meeting water quality standards and establish a TMDL for the pollutant or pollutants causing the failure to meet standards. Under a 1999 federal consent decree, TMDLs for over 100 Florida water bodies listed as impaired for mercury must be established by September 12, 2012. DEP has initiated a research program to provide the necessary information for setting the appropriate TMDLs for mercury. Among other things, the study will assess the relative contributions of mercury-emitting sources, such as coal-fired power plants, to mercury levels in surface waters.

Project Accomplishments:
Atmospheric & Environmental Research, Inc (AER) completed the literature review on mercury deposition in Florida; this document was sent to the FDEP Division of Air Resource Management and the TMDL team for review in February 2009. In addition, the Florida Electric Power Coordinating Group (FCG) Mercury Task Force met with the FDEP Division of Air Resource Management to discuss the review in January 2010. AER performed the Florida mercury deposition modeling for the Division of Air Resource Management. The FCG Mercury Task Force contracted with Tetra Tech to conduct aquatic field sampling, including an aquatics modeling report, to develop a "Conceptual Model for the Florida Mercury TMDL." This document was finalized and submitted to the FDEP in December 2010. Key personnel from AER were employed by Environ in 2011 and FCG established a contract with Environ to ensure continuity of the project. FCG used Environ and Tetra Tech to review and critique the FDEP's aquatic cycling and atmospheric modeling analyses. The FDEP has developed a draft mercury TMDL report, and it is scheduled to issue a proposed TMDL in September, 2012.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: $0 was projected to be spent in 2012.

Project Progress Summary:
The project is expected to conclude in 2012.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Project Title: **Integrated Clean Air Compliance Plan - Hazardous Air Pollutants (HAPs) ICR Program**
Project No. 14

Project Description:

In 2009, the U.S. Environmental Protection Agency (EPA) initiated efforts to develop an Information Collection Request ("ICR"), which requires that owners/operators of all coal- and oil-fired electric utility steam generating units provide information that will allow the EPA to assess the emissions of hazardous air pollutants from each such unit. The intention of the ICR is to assist the Administrator of the EPA in developing national emission standards for hazardous air pollutants under Section 112(d) of the Clean Air Act, 42 U.S.C. 7412. Pursuant to those efforts, by letter dated December 24, 2009, the EPA formally requested that PEF comply with certain data collection and emissions testing requirements for several of its steam electric generating units. The EPA letter states that initial submittal of existing information must be made within 90 days, and that the remaining data must be submitted within 8 months. Collection and submittal of the requested information is mandatory under Section 114 of the Clean Air Act, 42 U.S.C. 7414.

Project Accomplishments:
PEF completed and submitted the ICR to EPA during 2010. The HAPS ICR project is complete.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: No project expenditures for 2012 were incurred or budgeted.

Project Progress Summary:
PEF completed and submitted the ICR to EPA during 2010.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Project Title: **Effluent Limitation Guidelines ICR Program**
Project No. 15

Project Description:
The Effluent Limitation Guidelines ICR Program was created in response to Section 304 of the federal Clean Water Act which directs the U.S. EPA to develop and periodically review regulations, called effluent guidelines, to limit the amount of pollutants that are discharged to surface waters from various point source categories. 33 U.S.C. §13 14(b). In October 2009, EPA announced that it intended to update the effluent guidelines for the steam electric power generating point source category, which were last updated in 1982. PEF is required to complete the ICR and submit responses to U.S. EPA within 90 days. Collection and submittal of the requested information is mandatory under Section 308 of the Clean Water Act.

Project Accomplishments:
PEF completed and submitted the ICR to EPA in September 2010. The Effluent Limitation Guidelines ICR Program is complete.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: No project expenditures for 2012 were incurred or budgeted.

Project Progress Summary:
PEF completed and submitted the ICR to EPA in September 2010.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Project Title: **National Pollutant Discharge Elimination System (NPDES) - Energy**
Project No. 16

Project Description:
Pursuant to the federal Clean Water Act, 33 U.S.C. § 1342, all point source discharges to navigable waters from industrial facilities must obtain permits under the NPDES Program. The Florida Department of Environmental Protection (FDEP) administers the NPDES program in Florida. PEF's Anclote, Bartow, and Crystal River North, Crystal River South, and Suwannee NPDES permits were issued on January 19, 2011, February 14, 2011, July 21, 2011, March 9, 2012 and November 28, 2011 respectively. All facilities are required to meet new permitting conditions. In Docekt No. 110007-EI, the Commission approved recovery of costs associated with new requirements included or expected to be included in the new renewal permits, including: thermal studies, aquatic organism return studies and implementation, whole effluent toxicity testing, dissolved oxygen studies (Bartow only), and freeboard limitation related studies (Bartow only). As noted in PEF's February 8, 2012, program update, on December 14, 2011, FDEO issued a final NPDES renewal permit and associated Administrative Order for the Suwannee Plant. The Administrative Order includes a new requirement to

Project Accomplishments:
PEF has begun performing thermal studies, whole effluent toxicity testing, dissolved oxygen studies and freeboard limitation related studies and evaluations to comply with new permit requirements.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: O&M project variances for the 2012 were approximately $0.4 million due to reduced monitoring and cost, and regulatory delays.

Project Progress Summary:
PEF has begun complying with the requirements of the NPDES permits. Aquatic organism return study requirements have been postponed to align with the final EPA 316(b) rule requirements (Bartow/Anclote Plants). The aquatic organism return requirement is not a requirement in the Crystal River North plant NPDES permit.

Project Projections:
Estimated O&M and capital project expenditures for the period January 2013 through December 2013 are expected to be approximately $0.5 million in O&M costs and approximately $0.2 million in capital expenditures to ensure ongoing compliance with NPDES permits.

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Project Title: **Integrated Clean Air Compliance Plan - Mercury & Air Toxic Standards (MATS) - Energy**
Project No. 17.1 **Anclote Gas Conversion**

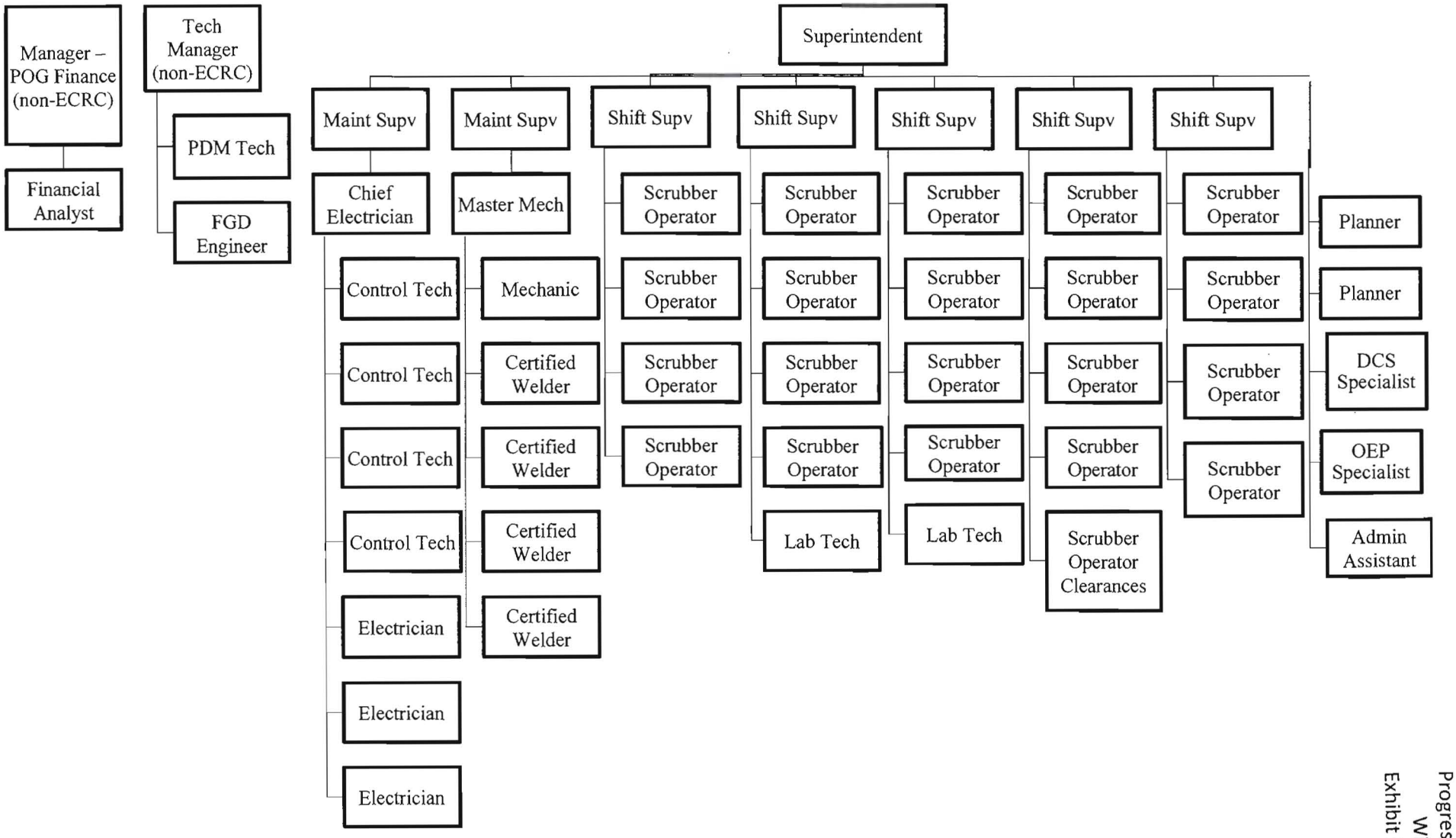
Project Description:
Convert existing Anclote Units to use 100% natural gas to be in compliance with Mercury and Air Toxics Standards (MATS) finaled by the EPA 12/16/11.

Project Accomplishments:
The project's major accomplishments to date are: finalized contract with OEM, finalized natural gas contract, and a draft air permit for public comment has been issued.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: PEF expects no O&M project expenditure variance for the year and capital investment variance of $22.2 million. This is a new project and therefore no projected spend amount was provided in Docket 110007-EI.

Project Progress Summary:
This project is on schedule with balance of plant engineering in progress and the development and insurance of the RFP for

Project Projections:
Estimated project expenditures for the period January 2013 through December 2013 are expected to be approximately $47.9 million.


Manager – POG Finance (non-ECRC)
Financial Analyst
Tech Manager (non-ECRC)
PDM Tech
FGD Engineer
Superintendent
Maint Supv
Maint Supv
Shift Supv
Shift Supv
Shift Supv
Shift Supv
Shift Supv
Chief Electrician
Master Mech
Control Tech
Control Tech
Control Tech
Control Tech
Electrician
Electrician
Electrician
Mechanic
Certified Welder
Certified Welder
Certified Welder
Certified Welder
Scrubber Operator
Scrubber Operator
Scrubber Operator
Scrubber Operator
Scrubber Operator
Lab Tech
Scrubber Operator
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Lab Tech
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Scrubber Operator

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 23
PARTY Progress Energy Florida
DESCRIPTION Jeff Swartz (TGF-3R), Forms 42-5P
DATE Page 7 of 20.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Integrated Clean Air Compliance Plan - Clean Air Interstate Rule (CAIR)**
Project Nos. (7.2, 7.3, & 7.4)

Project Description:
Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant new restrictions on emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") from power plants in 28 eastern states, including Florida, and the District of Columbia. The CAIR rule apportions region-wide SO_2 and NOx emission reduction requirements to the individual states, and further required each affected state to revise its State Implementation Plans (SIP) to include measures necessary to achieve its emission reduction budget within prescribed deadlines.

Project Accomplishments:
During 2012, the project team focused on completing the installation of the Hydrated Lime Injection System.

Project Fiscal Expenditures:
January 1, 2013 - December 31, 2013: PEF's capital expenditures for CAIR will be approximately $23.2 million lower than PEF's 2012 Projection filing. The difference is primarily attributable to the completion of the Hydrated Lime and SO3 probes projects in 2012.

Project Progress Summary:

For FGD Blowdown treatment, a wastewater treatment study is currenltly being performed by CH2MHill; the study is estimated to complete in October 2012. The study is being conducted in accordance with Conditions of Certification Modification P which requires the submission of an evaluation of alternative(s) to manage FGD blowdown.

Project Projections:
PEF expects approximately $27.9 million in O&M expenses and approximately $4.7 million in capital expenditures for this program.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120007-EI **EXHIBIT** 24

PARTY Progress Energy Florida, Inc.

DESCRIPTION George Hixon (TGF-3R); Forms 42-5P, 20 of 20

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Integrated Clean Air Compliance Plan - Mercury & Air Toxic Standards (MATS) - Energy**
Project No. 17.1 **Anclote Gas Conversion**

Project Description:
Convert existing Anclote Units to use 100% natural gas to be in compliance with Mercury and Air Toxics Standards (MATS) finaled by the EPA 12/16/11.

Project Accomplishments:
The project's major accomplishments to date are: finalized contract with OEM, finalized natural gas contract, and a draft air permit for public comment has been issued.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: PEF expects no O&M project expenditure variance for the year and capital investment variance of $22.2 million. This is a new project and therefore no projected spend amount was provided in Docket 110007-EI.

Project Progress Summary:
This project is on schedule with balance of plant engineering in progress and the development and insurance of the RFP for

Project Projections:
Estimated project expenditures for the period January 2013 through December 2013 are expected to be approximately $47.9 million.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Integrated Clean Air Compliance Plan - Mercury & Air Toxic Standards (MATS) - Energy**
Project No. 17.1 **Anclote Gas Conversion**

Project Description:
Convert existing Anclote Units to use 100% natural gas to be in compliance with Mercury and Air Toxics Standards (MATS) finaled by the EPA 12/16/11.

Project Accomplishments:
The project's major accomplishments to date are: finalized contract with OEM, finalized natural gas contract, and a draft air permit for public comment has been issued.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: PEF expects no O&M project expenditure variance for the year and capital investment variance of $22.2 million. This is a new project and therefore no projected spend amount was provided in Docket 110007-EI.

Project Progress Summary:
This project is on schedule with balance of plant engineering in progress and the development and insurance of the RFP for

Project Projections:
Estimated project expenditures for the period January 2013 through December 2013 are expected to be approximately $47.9 million.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 25
PARTY Progress Energy Florida
DESCRIPTION Cory Zeigler (TGF-3R), Forms 42-5P, Pgs 1,
DATE 2, 10, and 20 of 20.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Substation Environmental Investigation, Remediation, and Pollution Prevention**
Project No. 1

Project Description:
Chapter 376, Florida Statutes, requires that any person discharging a prohibited pollutant shall undertake to contain, remove, and abate the discharge to the satisfaction of the Florida Department of Environmental Protection (FDEP). Similarly, Chapter 403, Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For PEF to continue to comply with these statutes, it is conducting environmental investigation, remediation, and pollution prevention activities associated with its substation facilities to determine the existence of pollutant discharges, and if present, their removal and remediation. Activities also include development and implementation of best management and pollution prevention measures at these facilities.

Project Accomplishments:
PEF completed environmental remediations at 10 substations during 2012. Soil and groundwater sampling continue as well as remediation report writing. 245 remediations are completed out of 279 slated for completion. PEF is continuing to work with the FDEP on remaining remediations.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project expenditures are estimated to be approximately $1.2 million higher than originally projected. This variance is primarily due to multiple sites containing more contamination than originally projected as well as scheduling conflicts that resulted in sites being rescheduled from 2011 into 2012.

Project Progress Summary:
PEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

Project Projections:
Estimated project expenditures for 2013 are expected to be approximately $2.3 million.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Distribution System Environmental Investigation, Remediation, and Pollution Prevention**
Project No. 2

Project Description:
Chapter 376, Florida Statutes, requires that any person discharging a prohibited pollutant shall undertake to contain, remove, and abate the discharge to the satisfaction of the Florida Department of Environmental Protection (FDEP). Similarly, Chapter 403, Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For Progress Energy Florida to continue to comply with these statutes, it is conducting environmental investigation, remediation, and pollution prevention activities associated with its distribution system facilities to determine the existence of pollutant discharges, and if present, their removal and remediation. Activities also include development and implementation of best management and pollution prevention measures at these facilities.

Project Accomplishments:
In 2012, PEF completed all of the remaining identified abatement sites for the Transformer Replacement & Inspection Program (TRIP) program and completed deviation sampling on 9 sites. The cost for deviation sampling and potential remediation work at these 9 sites are included in the 2013 estimated TRIP costs. All TRIP remediations have been conducted in accordance with the FDEP approved Environmental Remediation Strategy.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project expenditures are estimated to be approximately $0.2 million higher than originally projected as a result of the 5 carryover abatement sites and delayed submittal of invoices to PEF from vendors.

Project Progress Summary:
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

Project Projections:
Estimated project expenditures for 2013 are expected to be approximately $0.2 million.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Sea Turtle - Coastal Street Lighting**
Project No. 9

Project Description:
PEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the Florida Department of Environmental Protection (FDEP), in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. The model ordinance is used by the local governments to develop and implement ordinances within their jurisdiction. To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County, City of Mexico Beach in Bay County and Pinellas County, all of which are within PEF's service territory. Since 2004, officials from the various local governments, as well as FDEP, FFWC, and USFWS, have advised PEF that lighting it owns and leases is affecting turtle nesting areas that fall within the scope of these ordinances. As a result, the local governments are requiring PEF to take additional measures to satisfy new criteria being applied to ensure compliance with the sea turtle ordinances.

Project Accomplishments:
PEF continues working with Franklin County, Gulf County, City of Mexico Beach and Pinellas County to mitigate any potential sea turtle nesting issues by retrofitting existing street lights, placing amber shields on existing HPS street lights and monitoring street lights for effectiveness in complying with sea turtle ordinances.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project expenditures are estimated to be approximately $2,500 lower than originally projected. This variance is primarily due to installing amber shields on a smaller quantity of street lights to prevent turtle disorientation than intially anticipated.

Project Progress Summary:
PEF is on schedule with the activities identified for this program.

Project Projections:
Estimated project expenditures for 2013 are expected to be approximately $5,000.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Integrated Clean Air Compliance Plan - Mercury & Air Toxic Standards (MATS) - Energy**
Project No. 17.1 **Anclote Gas Conversion**

Project Description:
Convert existing Anclote Units to use 100% natural gas to be in compliance with Mercury and Air Toxics Standards (MATS) finaled by the EPA 12/16/11.

Project Accomplishments:
The project's major accomplishments to date are: finalized contract with OEM, finalized natural gas contract, and a draft air permit for public comment has been issued.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: PEF expects no O&M project expenditure variance for the year and capital investment variance of $22.2 million. This is a new project and therefore no projected spend amount was provided in Docket 110007-EI.

Project Progress Summary:
This project is on schedule with balance of plant engineering in progress and the development and insurance of the RFP for

Project Projections:
Estimated project expenditures for the period January 2013 through December 2013 are expected to be approximately $47.9 million.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause
Commission Forms 42-1A Through 42-9A

January 2011 - December 2011
Final True-Up
Docket No. 120007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI **EXHIBIT** 26
PARTY Progress Energy Florida
DESCRIPTION Will Garrett (WG-1), Form 42-1A through
DATE 42-8A, 1/11-12/11.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011
(in Dollars)

Form 42-1A

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2011 through December 2011 (Form 42-2A, Line 5 + 6 + 10)	$ 863,786
2	Estimated/Actual True-Up Amount Approved for the Period January 2011 through December 2011 (Order No. PSC-11-0553-FOF-EI)	2,552,337
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2012 to December 2012 (Lines 1 - 2)	**$ (1,688,551)**

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Form 42-2A

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$15,126,181	$13,098,247	$11,705,358	$12,859,417	$15,274,316	$16,831,036	$17,500,000	$19,144,489	$17,875,891	$15,283,147	$13,309,168	$12,446,424	$180,453,673
2	True-Up Provision	$38,881,686	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	38,881,686
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$18,366,321	16,338,387	14,945,499	16,099,558	18,514,456	20,071,177	20,740,141	22,384,629	21,116,031	18,523,287	16,549,309	15,686,564	219,335,359
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		$3,290,933	3,258,044	4,181,938	4,247,023	3,872,417	5,811,433	4,839,565	5,930,036	5,525,205	5,218,110	3,244,689	3,869,029	53,288,422
	b. Capital Investment Projects (Form 42-7A, Line 9)		13,896,577	13,879,846	13,856,980	13,829,334	13,804,505	13,786,002	13,760,234	13,732,180	13,702,790	13,678,616	13,658,980	13,642,581	165,228,624
	c. Other														0
	d. Total Jurisdictional ECRC Costs		$17,187,510	17,137,890	18,038,918	18,076,357	17,676,922	19,597,435	18,599,799	19,662,216	19,227,995	18,896,726	16,903,669	17,511,610	218,517,046
5	Over/(Under) Recovery (Line 3 - Line 4d)		$1,178,811	(799,503)	(3,093,419)	(1,976,799)	837,534	473,742	2,140,342	2,722,414	1,888,036	(373,439)	(354,360)	(1,825,046)	818,313
6	Interest Provision (Form 42-3A, Line 10)		9,258	8,619	6,814	4,815	3,944	3,082	2,614	2,097	1,403	1,229	1,117	481	45,473
7	Beginning Balance True-Up & Interest Provision		38,881,686	36,829,614	32,798,590	26,471,845	21,259,720	18,861,057	16,097,740	15,000,556	14,484,926	13,134,225	9,521,874	5,928,491	38,881,686
	a. Deferred True-Up from January 2010 to December 2010 (Order No. PSC-11-0553-FOF-EI)		6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839
8	True-Up Collected/(Refunded) (see Line 2)		(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(38,881,686)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$43,062,453	39,031,429	32,704,684	27,492,559	25,093,896	22,330,579	21,233,395	20,717,765	19,367,064	15,754,713	12,161,330	7,096,625	7,096,625
10	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Lines 9 + 10)		$43,062,453	$39,031,429	$32,704,684	$27,492,559	$25,093,896	$22,330,579	21,233,395	$20,717,765	$19,367,064	$15,754,713	$12,161,330	$7,096,625	$7,096,625

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Form 42-3A

Interest Provision
(in Dollars)

Line	Description	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$45,114,525	$43,062,453	$39,031,429	$32,704,684	$27,492,559	$25,093,896	$22,330,579	$21,233,395	$20,717,765	$19,367,064	$15,754,713	$12,161,330	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	43,053,195	39,022,810	32,697,870	27,487,744	25,089,952	22,327,497	21,230,781	20,715,668	19,365,661	15,753,484	12,160,213	7,096,144	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	88,167,720	82,085,263	71,729,299	60,192,427	52,582,511	47,421,394	43,561,360	41,949,063	40,083,426	35,120,548	27,914,927	19,257,474	
4	Average True-Up Amount (Line 3 x 1/2)	44,083,860	41,042,632	35,864,650	30,096,214	26,291,256	23,710,697	21,780,680	20,974,532	20,041,713	17,560,274	13,957,464	9,628,737	
5	Interest Rate (Last Business Day of Prior Month)	0.25%	0.25%	0.25%	0.20%	0.19%	0.16%	0.16%	0.12%	0.11%	0.06%	0.11%	0.08%	
6	Interest Rate (Last Business Day of Current Month)	0.25%	0.25%	0.20%	0.19%	0.16%	0.16%	0.12%	0.11%	0.06%	0.11%	0.08%	0.03%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.50%	0.50%	0.45%	0.39%	0.35%	0.32%	0.28%	0.23%	0.17%	0.17%	0.19%	0.11%	
8	Average Interest Rate (Line 7 x 1/2)	0.250%	0.250%	0.225%	0.195%	0.175%	0.160%	0.140%	0.115%	0.085%	0.085%	0.095%	0.055%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.021%	0.021%	0.019%	0.016%	0.015%	0.013%	0.012%	0.010%	0.007%	0.007%	0.008%	0.005%	
10	Interest Provision for the Month (Line 4 x Line 9)	$9,258	$8,619	$6,814	$4,815	$3,944	$3,082	$2,614	$2,097	$1,403	$1,229	$1,117	$481	$45,473

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Variance Report of O&M Activities
(In Dollars)

Line		Description of O&M Activities - System	(1) YTD Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent
1		Description of O&M Activities - System				
	1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$6,280,889	$5,009,189	$1,271,700	25%
	1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	3,600,115	3,251,741	348,374	11%
	2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	6,993,901	6,954,534	39,367	1%
	3	Pipeline Integrity Management	1,375,012	1,592,997	(217,985)	-14%
	4	Above Ground Tank Secondary Containment	0	0	0	N/A
	5	SO2/NOx Emissions Allowances	5,920,396	5,642,301	278,095	5%
	6	Phase II Cooling Water Intake	0	0	0	N/A
	6.a	Phase II Cooling Water Intake 316(b) - Intm	0	0	0	N/A
	7.2	CAIR/CAMR - Peaking - Demand	89,036	121,200	(32,164)	-27%
	7.4	CAIR/CAMR Crystal River - Base	16,157,420	16,233,808	(76,388)	0%
	7.4	CAIR/CAMR Crystal River - Energy	13,749,932	12,326,703	1,423,229	12%
	7.4	CAIR/CAMR Crystal River - A&G	172,002	126,258	45,744	36%
	8	Arsenic Groundwater Standard - Base	(2)	(2)	(0)	0%
	9	Sea Turtle - Coastal Street Lighting - Distrib	1,235	1,991	(756)	-38%
	11	Modular Cooling Towers - Base	2,800,000	3,281,521	(481,521)	-15%
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	N/A
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	38,000	49,663	(11,663)	-23%
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	N/A
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	N/A
	16	National Pollutant Discharge Elimination System - Energy	143,211	648,334	(505,123)	-78%
	17	Mercury & Air Toxic Standards (MATS) - Energy	0	85,000	(85,000)	-100%
2		Total O&M Activities - Recoverable Costs	$57,321,147	$55,325,238	$1,995,909	4%
3		Recoverable Costs Allocated to Energy	19,851,539	18,752,001	1,099,538	6%
4		Recoverable Costs Allocated to Demand	37,469,608	36,573,237	896,371	2%

Notes:

Column (1) - End of Period Totals on Form 42-5A
Column (2) = 2011 Estimated/Actual Filing (8/1/11)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Form 42-5A

O&M Activities
(in Dollars)

Line	Description	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Description of O&M Activities													
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$546,422	$633,153	$600,196	$84,221	$623,720	$566,479	$526,860	$352,162	$314,717	$957,427	$674,456	$401,076	$6,280,889
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	486,865	221,152	443,243	578,289	117,201	374,251	386,054	300,791	356,572	200,975	33,053	101,668	3,600,115
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	622,226	823,044	901,921	421,788	677,391	726,364	502,343	515,003	492,229	414,405	89,231	807,955	6,993,901
3	Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	91,094	178,851	18,620	41,108	75,584	57,867	83,416	112,133	210,096	88,074	141,055	277,113	1,375,012
4	Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
5	SO2/NOx Emissions Allowances	336,510	152,899	247,154	652,356	671,414	691,940	711,663	715,569	645,144	364,864	429,863	301,021	5,920,396
6	Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
6a	Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	0	22,371	2,546	0	0	0	0	18,483	0	31,888	(6,523)	20,272	89,036
7.4	CAIR/CAMR Crystal River - Base	621,951	770,056	1,146,444	1,602,058	1,476,594	1,009,702	1,162,348	1,308,339	1,369,720	2,160,854	1,832,405	1,696,948	16,157,420
7.4	CAIR/CAMR Crystal River - Energy	860,823	773,753	1,085,947	1,012,680	542,795	1,990,846	1,739,175	1,542,541	1,748,032	1,463,140	418,874	571,326	13,749,932
7.4	CAIR/CAMR Crystal River - A&G	4,621	6,151	10,963	14,213	13,777	13,534	16,738	23,240	29,092	22,743	12,753	4,177	172,002
8	Arsenic Groundwater Standard - Base	(2)	(3,312)	0	0	3,312	0	0	0	0	0	0	0	(2)
9	Sea Turtle - Coastal Street Lighting - Distrib	15	0	0	0	1,000	0	0	0	23	197	0	0	1,235
11	Modular Cooling Towers - Base	0	0	0	0	0	700,000	0	1,400,000	700,000	0	0	0	2,800,000
12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Mercury Total Daily Maximum Loads Monitoring - Energy	9,500	0	9,500	0	0	9,500	0	0	9,500	0	0	0	38,000
14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0		0	0	0	0	0	0	0	0	0	0
15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
16	National Pollutant Discharge Elimination System - Energy	0	0	0	4,270	4,270	21,309	32,294	17,181	8,945	27,011	7,547	20,385	143,211
17	Mercury & Air Toxic Standards (MATS) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total of O&M Activities	3,580,024	3,578,118	4,466,535	4,410,982	4,207,058	6,161,791	5,160,891	6,305,442	5,884,072	5,731,579	3,632,714	4,201,942	**$57,321,147**
3	Recoverable Costs Allocated to Energy	1,206,833	926,652	1,342,602	1,669,306	1,218,478	2,713,595	2,483,133	2,275,291	2,411,621	1,855,015	856,284	892,732	19,851,539
4	Recoverable Costs Allocated to Demand - Transm	546,422	633,153	600,196	84,221	623,720	566,479	526,860	352,162	314,717	957,427	674,456	401,076	6,280,889
	Recoverable Costs Allocated to Demand - Distrib	1,109,106	1,044,196	1,345,164	1,000,077	795,593	1,100,614	888,397	815,795	848,825	615,578	122,284	909,623	10,595,252
	Recoverable Costs Allocated to Demand - Prod-Base	621,948	766,744	1,146,444	1,602,058	1,479,906	1,709,702	1,162,348	2,708,339	2,069,720	2,160,854	1,832,405	1,696,948	18,957,417
	Recoverable Costs Allocated to Demand - Prod-Intm	91,094	178,851	18,620	41,108	75,584	57,867	83,416	112,133	210,096	88,074	141,055	277,113	1,375,012
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	22,371	2,546	0	0	0	0	18,483	0	31,888	(6,523)	20,272	89,036
	Recoverable Costs Allocated to Demand - A&G	4,621	6,151	10,963	14,213	13,777	13,534	16,738	23,240	29,092	22,743	12,753	4,177	172,002
5	Retail Energy Jurisdictional Factor	0.96010	0.98220	0.99420	0.99600	0.98930	0.98770	0.98010	0.98430	0.97900	0.98110	0.98750	0.99230	
6	Retail Transmission Demand Jurisdictional Factor	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
	Retail Production Demand Jurisdictional Factor - Base	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
	Retail Production Demand Jurisdictional Factor - Intm	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
	Retail Production Demand Jurisdictional Factor - Peaking	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
	Retail Production Demand Jurisdictional Factor - A&G	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	
7	Jurisdictional Energy Recoverable Costs (A)	1,158,680	910,157	1,334,815	1,662,629	1,205,441	2,680,217	2,433,718	2,239,569	2,360,977	1,819,955	845,580	885,858	19,537,596
8	Jurisdictional Demand Recoverable Costs - Transm (B)	379,851	440,143	417,233	58,547	433,585	393,794	366,252	244,809	218,779	665,565	468,855	278,812	4,366,225
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,104,935	1,040,270	1,340,106	996,316	792,601	1,096,476	885,057	812,727	845,634	613,264	121,824	906,203	10,555,413
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	577,118	711,477	1,063,809	1,486,582	1,373,234	1,586,467	1,078,566	2,513,122	1,920,535	2,005,100	1,700,325	1,574,632	17,590,967
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	66,080	129,740	13,507	29,820	54,830	41,977	60,511	81,342	152,406	63,889	102,323	201,021	997,446
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	20,575	2,341	0	0	0	0	16,999	0	29,328	(5,999)	18,644	81,888
	Jurisdictional Demand Recoverable Costs - A&G	4,269	5,682	10,127	13,129	12,726	12,502	15,461	21,468	26,874	21,009	11,781	3,859	158,887
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$3,290,933	$3,258,044	$4,181,938	$4,247,023	$3,872,417	$5,811,433	$4,839,565	$5,930,036	$5,525,205	$5,218,110	$3,244,689	$3,869,029	$53,288,422

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Variance Report of Capital Investment Activities
(In Dollars)

Line		(1) YTD Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities				
	3.x Pipeline Integrity Management - Bartow/Anclote Pipeline	$446,706	$447,925	($1,220)	0%
	4.x Above Ground Tank Secondary Containment	1,922,127	1,955,440	(33,313)	-2%
	5 SO2 Emissions Allowances	3,158,438	3,165,343	(6,905)	0%
	7.x CAIR/CAMR	172,298,783	172,395,718	(96,935)	0%
	9 Sea Turtle - Coastal Street Lighting	1,398	1,480	(82)	-6%
	10.x Underground Storage Tanks	31,600	31,599	1	0%
	11 Modular Cooling Towers	82,510	82,510	0	0%
	11.1 Thermal Discharge Permanent Cooling Tower	48,108	48,108	0	0%
	16.0 National Pollutant Discharge Elimination System (NPDES) - Intermediate	825	0	825	100%
2	Total Capital Investment Activities - Recoverable Costs	$177,990,495	$178,126,123	($137,628)	0%
3	Recoverable Costs Allocated to Energy	3,225,968	3,221,905	$4,063	0%
4	Recoverable Costs Allocated to Demand	$174,764,527	$174,906,218	($141,692)	0%

Notes:

Column (1) - End of Period Totals on Form 42-7A
Column (2) = 2011 Estimated/Actual Filing (8/1/11)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Form 42-7A

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$37,172	$37,101	$37,030	$36,960	$37,065	$37,299	37,371	$37,300	$37,229	$37,159	$37,232	$37,788	$446,706
4.1	Above Ground Tank Secondary Containment - Peaking	122,954	122,675	122,427	122,284	122,269	122,142	121,953	123,240	125,473	127,296	128,104	131,914	1,492,731
4.2	Above Ground Tank Secondary Containment - Base	32,966	32,945	32,864	32,794	32,770	32,734	32,678	32,623	32,567	32,512	32,457	32,401	392,311
4.3	Above Ground Tank Secondary Containment - Intermediate	3,117	3,112	3,108	3,102	3,098	3,093	3,088	3,083	3,079	3,073	3,068	3,064	37,085
5	SO2/NOX Emissions Allowances - Energy	287,609	285,371	283,541	279,413	273,346	267,111	260,682	254,145	247,923	243,303	239,668	236,326	3,158,438
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR CT's - Peaking	21,459	21,428	21,395	21,362	21,343	21,318	21,286	21,254	21,221	21,189	21,156	21,124	255,535
7.3	CAMR Crystal River - Base	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
7.4	CAIR/CAMR Crystal River AFUDC - Base	14,445,526	14,423,381	14,398,017	14,372,454	14,353,568	14,339,552	14,323,462	14,305,836	14,278,420	14,254,208	14,234,173	14,215,393	171,943,990
7.4	CAIR/CAMR Crystal River AFUDC - Energy	3,779	3,818	3,323	3,379	4,062	5,292	5,609	6,035	7,683	8,452	8,483	7,616	67,530
9	Sea Turtle - Coastal Street Lighting -Distribution	118	118	117	117	117	116	116	116	116	116	116	115	1,398
10.1	Underground Storage Tanks - Base	1,790	1,787	1,785	1,782	1,779	1,776	1,774	1,771	1,768	1,765	1,763	1,760	21,300
10.2	Underground Storage Tanks - Intermediate	868	867	865	863	861	860	857	856	853	852	850	848	10,300
11	Modular Cooling Towers - Base	12,159	12,057	11,956	11,855	11,753	11,651	8,889	438	438	438	438	438	82,510
11.1	Crystal River Thermal Discharge Compliance Project - Base	4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
16.0	National Pollutant Discharge Elimination System (NPDES) - Intermediate	0	0	0	0	0	0	0	0	0	0	275	550	825
2	Total Investment Projects - Recoverable Costs	$14,976,196	$14,951,334	$14,923,098	$14,893,029	$14,868,691	$14,849,599	$14,824,416	$14,793,343	$14,763,411	$14,737,000	$14,714,415	$14,695,964	$177,990,495
3	Recoverable Costs Allocated to Energy	291,388	289,189	286,864	282,792	277,408	272,403	266,291	260,180	255,606	251,755	248,151	243,942	3,225,968
	Recoverable Costs Allocated to Demand	118	118	117	117	117	116	116	116	116	116	116	115	1,398
4	Recoverable Costs Allocated to Demand - Production - Base	14,499,120	14,476,844	14,451,292	14,425,549	14,406,530	14,392,368	14,373,454	14,347,314	14,319,834	14,295,560	14,275,463	14,256,619	172,519,947
	Recoverable Costs Allocated to Demand - Production - Intermediate	41,157	41,080	41,003	40,925	41,024	41,252	41,316	41,239	41,161	41,084	41,425	42,250	494,916
	Recoverable Costs Allocated to Demand - Production - Peaking	144,413	144,103	143,822	143,646	143,612	143,460	143,239	144,494	146,694	148,485	149,260	153,038	1,748,266
5	Retail Energy Jurisdictional Factor	0.96010	0.98220	0.99420	0.99600	0.98930	0.98770	0.98010	0.98430	0.97900	0.98110	0.98750	0.99230	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
6	Retail Demand Jurisdictional Factor - Production - Base	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
7	Jurisdictional Energy Recoverable Costs (B)	279,761	284,041	285,200	281,661	274,439	269,053	260,992	256,095	250,238	246,997	245,049	242,064	3,175,591
	Jurisdictional Demand Recoverable Costs (B)	118	118	117	117	117	116	116	116	116	116	116	115	1,393
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	13,454,023	13,433,353	13,409,643	13,385,755	13,368,107	13,354,966	13,337,415	13,313,160	13,287,660	13,265,136	13,246,488	13,229,002	160,084,709
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	29,856	29,800	29,744	29,687	29,759	29,925	29,971	29,915	29,859	29,803	30,050	30,648	359,017
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	132,820	132,534	132,276	132,114	132,083	131,943	131,740	132,894	134,917	136,565	137,277	140,752	1,607,915
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$13,896,577	$13,879,846	$13,856,980	$13,829,334	$13,804,505	$13,786,002	13,760,234	$13,732,180	$13,702,790	$13,678,616	$13,658,980	$13,642,581	$165,228,624

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9, Form 42-8A, Line 5 for Projects 5 - Allowances and Project 7. 4 - Reagents
(B) Line 3 x Line 5
(C) Line 4 x Line 6

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$35,509	$31,260	$40	$0	$0	$0	$31,534	$40,984	$139,327
	b. Clearings to Plant			0	0	0	0	4,259	0	0	0	0	0	0	135,068	139,327
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,583,995	3,583,995	3,583,995	3,583,995	3,583,995	3,583,995	3,583,995	3,719,062	
3	Less: Accumulated Depreciation		(658,240)	(665,976)	(673,712)	(681,448)	(689,184)	(696,929)	(704,674)	(712,419)	(720,164)	(727,909)	(735,654)	(743,399)	(751,335)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	31,250	62,510	62,550	62,550	62,550	62,550	94,084	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,921,496	$2,913,760	$2,906,024	$2,898,288	$2,890,552	$2,918,316	$2,941,831	$2,934,125	$2,926,380	$2,918,635	$2,910,890	$2,934,680	$2,967,727	
6	Average Net Investment			$2,917,628	$2,909,892	$2,902,156	$2,894,420	$2,904,434	$2,930,073	$2,937,978	$2,930,253	$2,922,508	$2,914,763	$2,922,785	$2,951,203	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		7,178	7,159	7,140	7,121	7,146	7,209	7,228	7,209	7,190	7,171	7,191	7,261	86,203
	b. Equity Component Grossed Up For Taxes	8.02%		19,508	19,456	19,404	19,353	19,420	19,591	19,644	19,592	19,540	19,489	19,542	19,732	234,271
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			7,736	7,736	7,736	7,736	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,937	93,096
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes (D)			2,750	2,750	2,750	2,750	2,754	2,754	2,754	2,754	2,754	2,754	2,754	2,858	33,136
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$37,172	$37,101	$37,030	$36,960	$37,065	$37,299	$37,371	$37,300	$37,229	$37,159	$37,232	$37,788	446,706
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$37,172	$37,101	$37,030	$36,960	$37,065	$37,299	$37,371	$37,300	$37,229	$37,159	$37,232	$37,788	446,706
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			26,965	26,913	26,862	26,811	26,887	27,057	27,109	27,058	27,006	26,956	27,008	27,411	324,045
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$26,965	$26,913	$26,862	$26,811	$26,887	$27,057	$27,109	$27,058	$27,006	$26,956	$27,008	$27,411	$324,045

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Peaking (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$6,710	$23,150	$23,636	$9,543	$10,474	$331,969	$217,248	$242,705	($5,057)	$371,492	$1,231,871
	b. Clearings to Plant			0	0	0	0	14,528	0	0	0	0	0	0	1,217,343	1,231,871
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		10,064,665	10,064,666	10,064,666	10,064,666	10,064,666	10,079,193	10,079,193	10,079,193	10,079,193	10,079,193	10,079,193	10,079,193	11,296,536	
3	Less: Accumulated Depreciation		(843,390)	(873,896)	(904,402)	(934,908)	(965,414)	(995,956)	(1,026,498)	(1,057,040)	(1,087,582)	(1,118,124)	(1,148,666)	(1,179,208)	(1,211,068)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	6,709	29,859	38,967	48,511	58,985	390,954	608,201	850,907	845,850	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$9,221,275	$9,190,769	$9,160,263	$9,136,466	$9,129,111	$9,122,205	$9,101,206	$9,081,138	$9,382,565	$9,569,271	$9,781,434	$9,745,835	$10,085,468	
6	Average Net Investment			$9,206,022	$9,175,516	$9,148,365	$9,132,788	$9,125,658	$9,111,705	$9,091,172	$9,231,852	$9,475,918	$9,675,352	$9,763,635	9,915,651	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		22,650	22,575	22,508	22,470	22,452	22,418	22,367	22,713	23,314	23,804	24,022	24,396	275,689
	b. Equity Component Grossed Up For Taxes	8.02%		61,553	61,349	61,168	61,063	61,016	60,923	60,785	61,726	63,358	64,691	65,281	66,298	749,211
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			30,506	30,506	30,506	30,506	30,542	30,542	30,542	30,542	30,542	30,542	30,542	31,860	367,678
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes (D)			8,245	8,245	8,245	8,245	8,259	8,259	8,259	8,259	8,259	8,259	8,259	9,360	100,153
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$122,954	$122,675	$122,427	$122,284	$122,269	$122,142	$121,953	$123,240	$125,473	$127,296	$128,104	$131,914	1,492,731
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$122,954	$122,675	$122,427	$122,284	$122,269	$122,142	$121,953	$123,240	$125,473	$127,296	$128,104	$131,914	1,492,731
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			113,083	112,827	112,599	112,467	112,453	112,336	112,163	113,346	115,400	117,077	117,820	121,324	1,372,895
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$113,083	$112,827	$112,599	$112,467	$112,453	$112,336	$112,163	$113,346	$115,400	$117,077	$117,820	$121,324	$1,372,895

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Sec Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Sec Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$7,706	$0	($3,398)	$0	$4,153	$0	$0	$0	$0	$0	$0	$0	$8,461
	b. Clearings to Plant			7,706	0	(3,398)	0	4,153	0	0	0	0	0	0	0	8,461
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,877,810	2,885,516	2,885,516	2,882,118	2,882,118	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	
3	Less: Accumulated Depreciation		(143,326)	(149,371)	(155,416)	(161,453)	(167,490)	(173,536)	(179,582)	(185,628)	(191,674)	(197,720)	(203,766)	(209,812)	(215,858)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$2,734,484	$2,736,146	$2,730,101	$2,720,666	$2,714,629	$2,712,735	$2,706,689	$2,700,643	$2,694,597	$2,688,551	$2,682,505	$2,676,459	$2,670,413	
6	Average Net Investment			$2,735,315	$2,733,123	$2,725,383	$2,717,647	$2,713,682	$2,709,712	$2,703,666	$2,697,620	$2,691,574	$2,685,528	$2,679,482	$2,673,436	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		6,730	6,724	6,705	6,686	6,677	6,667	6,652	6,637	6,622	6,607	6,592	6,577	79,876
	b. Equity Component Grossed Up For Taxes	8.02%		18,289	18,274	18,222	18,171	18,144	18,118	18,077	18,037	17,996	17,956	17,916	17,875	217,075
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			6,045	6,045	6,037	6,037	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	72,532
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,902	1,902	1,900	1,900	1,903	1,903	1,903	1,903	1,903	1,903	1,903	1,903	22,828
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$32,966	$32,945	$32,864	$32,794	$32,770	$32,734	$32,678	$32,623	$32,567	$32,512	$32,457	$32,401	392,311
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$32,966	$32,945	$32,864	$32,794	$32,770	$32,734	$32,678	$32,623	$32,567	$32,512	$32,457	$32,401	392,311
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			30,590	30,570	30,495	30,430	30,408	30,375	30,323	30,272	30,220	30,169	30,117	30,066	364,033
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$30,590	$30,570	$30,495	$30,430	$30,408	$30,375	$30,323	$30,272	$30,220	$30,169	$30,117	$30,066	$364,033

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(28,602)	(29,134)	(29,666)	(30,198)	(30,730)	(31,262)	(31,794)	(32,326)	(32,858)	(33,390)	(33,922)	(34,454)	(34,986)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$261,696	$261,164	$260,632	$260,100	$259,568	$259,036	$258,504	$257,972	$257,440	$256,908	$256,376	$255,844	$255,312	
6	Average Net Investment			$261,430	$260,898	$260,366	$259,834	$259,302	$258,770	$258,238	$257,706	$257,174	$256,642	$256,110	$255,578	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		643	642	641	639	638	637	635	634	633	631	630	629	7,632
	b. Equity Component Grossed Up For Taxes	8.02%		1,748	1,744	1,741	1,737	1,734	1,730	1,727	1,723	1,720	1,716	1,712	1,709	20,741
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			194	194	194	194	194	194	194	194	194	194	194	194	2,328
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,117	$3,112	$3,108	$3,102	$3,098	$3,093	$3,088	$3,083	$3,079	$3,073	$3,068	$3,064	37,085
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$3,117	$3,112	$3,108	$3,102	$3,098	$3,093	$3,088	$3,083	$3,079	$3,073	$3,068	$3,064	37,085
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			2,261	2,257	2,255	2,250	2,247	2,244	2,240	2,236	2,234	2,229	2,226	2,223	26,902
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,261	$2,257	$2,255	$2,250	$2,247	$2,244	$2,240	$2,236	$2,234	$2,229	$2,226	$2,223	$26,902

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Sec Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Sec Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Working Capital Dr (Cr)														
	a. 1581001 SO_2 Emission Allowance Inventory	5,674,079	$5,635,633	$5,624,251	$5,597,851	$5,502,898	$5,411,179	$5,328,381	$5,254,444	$5,169,875	$5,115,238	$5,072,688	$5,015,318	$4,978,189	$4,978,189
	b. 25401FL Auctioned SO_2 Allowance	(1,776,566)	(1,758,207)	(1,739,848)	(1,721,489)	(1,704,491)	(1,685,729)	(1,666,967)	(1,650,355)	(1,631,593)	(1,612,831)	(1,594,069)	(1,575,307)	(1,556,546)	(1,556,546)
	c. 1581002 NOx Emission Allowance Inventory	27,715,427	27,399,003	27,239,127	27,000,013	26,422,640	25,824,183	25,196,280	24,539,791	23,890,030	23,280,761	22,939,685	22,548,430	22,265,776	22,265,776
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital	$31,612,939	$31,276,429	$31,123,530	$30,876,375	$30,221,047	$29,549,634	$28,857,694	$28,143,880	$27,428,311	$26,783,167	$26,418,303	$25,988,441	$25,687,420	$25,687,420
3	Average Net Investment		$31,444,684	$31,199,979	$30,999,953	$30,548,711	$29,885,341	$29,203,664	$28,500,787	$27,786,095	$27,105,739	$26,600,735	$26,203,372	$25,837,930	
4	Return on Average Net Working Capital Balance (A)														
	a. Debt Component (Line 3 x 2.95% x 1/12) 2.95%		77,364	76,762	76,270	75,159	73,527	71,850	70,121	68,362	66,689	65,446	64,468	63,569	849,587
	b. Equity Component Grossed Up For Taxes 8.02%		210,245	208,609	207,271	204,254	199,819	195,261	190,561	185,783	181,234	177,857	175,200	172,757	2,308,851
5	Total Return Component (B)		$287,609	$285,371	$283,541	$279,413	$273,346	$267,111	$260,682	$254,145	$247,923	$243,303	$239,668	$236,326	3,158,438
6	Expense Dr (Cr)														
	a. 5090001 SO_2 Allowance Expense		38,445	11,382	26,400	94,952	91,719	82,798	73,937	84,569	54,637	42,550	57,370	37,129	695,889
	b. 4074004 Amortization Expense		(18,359)	(18,359)	(18,359)	(19,970)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(225,143)
	c. 5090003 NOx Allowance Expense		316,424	159,876	239,114	577,374	598,456	627,904	656,488	649,761	609,269	341,076	391,255	282,654	5,449,651
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)		336,510	152,899	247,154	652,356	671,414	691,940	711,663	715,569	645,144	364,864	429,863	301,021	5,920,396
8	Total System Recoverable Expenses (Lines 5 + 7)		$624,119	$438,270	$530,695	$931,769	$944,760	$959,051	$972,345	$969,714	$893,067	$608,167	$669,531	$537,347	9,078,834
	a. Recoverable costs allocated to Energy		624,119	438,270	530,695	931,769	944,760	959,051	972,345	969,714	893,067	608,167	669,531	537,347	9,078,834
	b. Recoverable costs allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor		0.96010	0.98220	0.99420	0.99600	0.98930	0.98770	0.98010	0.98430	0.97900	0.98110	0.98750	0.99230	
10	Demand Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)		$599,216	$430,468	$527,617	$928,042	$934,651	$947,255	$952,996	$954,489	$874,313	$596,673	$661,162	$533,209	8,940,091
12	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)		$ 599,216	$ 430,468	$ 527,617	$ 928,042	$ 934,651	$ 947,255	$ 952,996	$ 954,489	$ 874,313	$ 596,673	$ 661,162	$ 533,209	$ 8,940,091

Notes:
(A) Line 3 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc Tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Intermediate (Project 7.1 - Anclote Low Nox Burners and SOFA)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment (B)														
	a. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes 8.02%		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
8	Investment Expenses														
	a. Depreciation (C) 1.60%		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. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.008000		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intm)		0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$1,708	$0	$0	$0	$0	$0	$0	$0	$1,708
	b. Clearings to Plant			0	0	0	0	1,708	0	0	0	0	0	0	0	1,708
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	
3	Less: Accumulated Depreciation		(133,504)	(137,044)	(140,584)	(144,124)	(147,664)	(151,208)	(154,752)	(158,296)	(161,840)	(165,384)	(168,928)	(172,472)	(176,016)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,800,896	$1,797,356	$1,793,816	$1,790,276	$1,786,736	$1,784,900	$1,781,356	$1,777,812	$1,774,268	$1,770,724	$1,767,180	$1,763,636	$1,760,092	
6	Average Net Investment			$1,799,127	$1,795,587	$1,792,047	$1,788,507	$1,785,819	$1,783,128	$1,779,584	$1,776,040	$1,772,496	$1,768,952	$1,765,408	$1,761,864	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,426	4,418	4,409	4,400	4,394	4,387	4,378	4,370	4,361	4,352	4,343	4,335	52,573
	b. Equity Component Grossed Up For Taxes	8.02%		12,029	12,006	11,982	11,958	11,940	11,922	11,899	11,875	11,851	11,828	11,804	11,780	142,874
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			3,540	3,540	3,540	3,540	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	42,512
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,464	1,464	1,464	1,464	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	17,576
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$21,459	$21,428	$21,395	$21,362	$21,343	$21,318	$21,286	$21,254	$21,221	$21,189	$21,156	$21,124	255,535
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$21,459	$21,428	$21,395	$21,362	$21,343	$21,318	$21,286	$21,254	$21,221	$21,189	$21,156	$21,124	255,535
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			19,736	19,708	19,677	19,647	19,630	19,607	19,577	19,548	19,517	19,488	19,458	19,428	235,021
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$19,736	$19,708	$19,677	$19,647	$19,630	$19,607	$19,577	$19,548	$19,517	$19,488	$19,458	$19,428	$235,021

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002) Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
5	Net Investment (Lines 2 + 3 + 4)		$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	
6	Average Net Investment			$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		711	711	711	711	711	711	711	711	711	711	711	711	$8,532
	b. Equity Component Grossed Up For Taxes	8.02%		1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	23,196
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.10%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007910		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	31,728
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	31,728
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	29,441
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,453	$2,453	$2,453	$2,453	$2,453	$2,453	$2,453	$2,453	$2,453	$2,453	$2,453	$2,453	$29,441

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base - AFUDC (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$906,482	($378,850)	($17,178)	($268,881)	$826,060	$790,589	$516,839	$490,467	($1,075,983)	$432,586	$232,126	$560,110	$3,014,365
	b. Clearings to Plant			542,977	(427,874)	(61,081)	(319,027)	711,087	737,537	477,766	432,863	472,318	432,586	223,441	354,748	3,577,341
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,242,647,327	1,243,190,303	1,242,762,429	1,242,701,348	1,242,382,321	1,243,093,409	1,243,830,946	1,244,308,712	1,244,741,575	1,245,213,892	1,245,646,479	1,245,869,920	1,246,224,667	
3	Less: Accumulated Depreciation		(32,451,621)	(35,009,075)	(37,565,638)	(40,122,073)	(42,677,844)	(45,235,092)	(47,793,840)	(50,353,612)	(52,914,287)	(55,473,326)	(58,034,222)	(60,595,322)	(63,157,213)	
4	CWIP - Non-Interest Bearing		777,023	1,140,528	1,189,551	1,233,454	1,283,599	1,398,572	1,451,623	1,490,696	1,548,300	(0)	(0)	8,584	214,046	
5	Net Investment (Lines 2 + 3 + 4)		$1,210,972,728	$1,209,321,756	$1,206,386,342	$1,203,812,729	$1,200,988,077	$1,199,256,889	$1,197,488,729	$1,195,445,797	$1,193,375,589	$1,189,740,567	$1,187,612,257	$1,185,283,282	$1,183,281,501	
6	Average Net Investment			$1,210,147,241	$1,207,854,049	$1,205,099,535	$1,202,400,401	$1,200,122,481	$1,198,372,809	$1,196,467,262	$1,194,410,693	$1,191,558,076	$1,188,676,412	$1,186,447,767	$1,184,282,390	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,977,341	2,971,699	2,964,920	2,958,280	2,952,678	2,948,372	2,943,685	2,938,622	2,931,605	2,924,516	2,919,031	2,913,705	35,344,454
	b. Equity Component Grossed Up For Taxes	8.02%		8,091,261	8,075,930	8,057,515	8,039,466	8,024,235	8,012,539	7,999,798	7,986,047	7,966,973	7,947,707	7,932,805	7,918,328	96,052,604
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			2,557,454	2,556,563	2,556,435	2,555,771	2,557,248	2,558,748	2,559,772	2,560,675	2,559,039	2,560,896	2,561,100	2,561,891	30,705,592
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			819,470	819,189	819,147	818,937	819,407	819,893	820,207	820,492	820,803	821,089	821,237	821,469	9,841,340
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,445,526	14,423,381	14,398,017	14,372,454	14,353,568	14,339,552	14,323,462	14,305,836	14,278,420	14,254,208	14,234,173	14,215,393	171,943,990
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			14,445,526	14,423,381	14,398,017	14,372,454	14,353,568	14,339,552	14,323,462	14,305,836	14,278,420	14,254,208	14,234,173	14,215,393	171,943,990
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			13,404,292	13,383,744	13,360,208	13,336,488	13,318,963	13,305,957	13,291,027	13,274,671	13,249,231	13,226,765	13,208,174	13,190,747	159,550,267
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$13,404,292	$13,383,744	$13,360,208	$13,336,488	$13,318,963	$13,305,957	$13,291,027	$13,274,671	$13,249,231	$13,226,765	$13,208,174	$13,190,747	$159,550,267

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Schedule of Amortization and Return
For Project: CAIR/CAMR - Base - AFUDC (Project 7.4 - Reagents and By-products)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1544001 Ammonia Inventory		**$50,759**	$15,165	$27,675	$11,578	$43,583	$30,411	$71,491	$37,013	$49,813	$44,951	$55,998	$29,706	$21,613	$21,613
	b. 1544004 Limestone Inventory		**351,659**	408,637	383,343	304,085	379,549	434,565	620,752	497,230	735,577	849,606	897,666	871,492	742,609	742,609
2	Total Working Capital		**$402,418**	423,802	411,018	315,663	423,132	464,977	692,243	534,242	785,390	894,557	953,664	901,198	764,222	764,222
3	Average Net Investment			413,110	417,410	363,340	369,398	444,054	578,610	613,243	659,816	839,973	924,110	927,431	832,710	
4	Return on Average Net Working Capital Balance (A)															
	a. Debt Component (Line 3 x 2.95% x 1/12)	2.95%		1,016	1,027	894	909	1,093	1,424	1,509	1,623	2,067	2,274	2,282	2,049	$18,165
	b. Equity Component Grossed Up For Taxes	8.02%		2,762	2,791	2,429	2,470	2,969	3,869	4,100	4,412	5,616	6,179	6,201	5,568	49,365
5	Total Return Component (B)			3,779	3,818	3,323	3,379	4,062	5,292	5,609	6,035	7,683	8,452	8,483	7,616	67,530
6	Expense Dr (Cr)															
	a. 5020011 Ammonia Expense			386,148	272,242	329,813	331,400	303,026	365,735	385,006	403,853	281,229	246,773	206,406	199,468	3,711,100
	b. 5020012 Limestone Expense			347,053	280,410	306,652	294,359	321,811	303,283	358,144	427,482	465,306	428,874	184,857	308,094	4,026,325
	c. 5020013 Dibasic Acid Expense			0	0	0	0	0	0	0	0	0	0	5,281	3,245	8,527
	d. 5020003 Gypsum Disposal/Sale			127,623	221,100	406,513	357,711	(82,572)	1,313,296	667,844	702,767	1,001,032	772,739	11,908	50,020	5,549,981
	e. 5020014 Bottom/Fly Ash Reagents Expense			0	0	42,969	29,210	528	8,532	328,181	8,439	465	14,754	10,422	10,498	453,999
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			860,823	773,753	1,085,947	1,012,680	542,795	1,990,846	1,739,175	1,542,541	1,748,032	1,463,140	418,874	571,326	13,749,932
8	Total System Recoverable Expenses (Lines 5 + 7)			864,602	777,571	1,089,270	1,016,059	546,856	1,996,138	1,744,784	1,548,576	1,755,715	1,471,593	427,357	578,942	13,817,462
	a. Recoverable costs allocated to Energy			864,602	777,571	1,089,270	1,016,059	546,856	1,996,138	1,744,784	1,548,576	1,755,715	1,471,593	427,357	578,942	13,817,462
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96010	0.98220	0.99420	0.99600	0.98930	0.98770	0.98010	0.98430	0.97900	0.98110	0.98750	0.99230	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			830,104	763,730	1,082,953	1,011,994	541,005	1,971,586	1,710,063	1,524,263	1,718,845	1,443,780	422,015	574,484	13,594,821
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$830,104	$ 763,730	$1,082,953	$1,011,994	$ 541,005	$1,971,586	$1,710,063	$1,524,263	$ 1,718,845	$1,443,780	$ 422,015	$ 574,484	$13,594,821

Notes:
(A) Line 3 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description	Beginning of Period Amoun	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	
3	Less: Accumulated Depreciation	(1,012)	(1,038)	(1,064)	(1,090)	(1,116)	(1,142)	(1,168)	(1,194)	(1,220)	(1,246)	(1,272)	(1,298)	(1,324)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$9,187	$9,161	$9,135	$9,109	$9,083	$9,057	$9,031	$9,005	$8,979	$8,953	$8,927	$8,901	$8,875	
6	Average Net Investment		9,174	9,148	9,122	9,096	9,070	9,044	9,018	8,992	8,966	8,940	8,914	8,888	
7	Return on Average Net Investment (B)														
	a. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		23	23	22	22	22	22	22	22	22	22	22	22	$266
	b. Equity Component Grossed Up For Taxes 8.02%		61	61	61	61	61	60	60	60	60	60	60	59	724
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.10%		26	26	26	26	26	26	26	26	26	26	26	26	312
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.009602		8	8	8	8	8	8	8	8	8	8	8	8	96
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		118	118	117	117	117	116	116	116	116	116	116	115	1,398
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		118	118	117	117	117	116	116	116	116	116	116	115	1,398
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)		0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)		118	118	117	117	117	116	116	116	116	116	116	115	1,393
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$118	$118	$117	$117	$117	$116	$116	$116	$116	$116	$116	$115	$1,393

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 120007-EI
Progress Energy Florida
Witness: Will Garrett
Exh. No. __ (WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Base (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		(17,584)	(17,880)	(18,176)	(18,472)	(18,768)	(19,064)	(19,360)	(19,656)	(19,952)	(20,248)	(20,544)	(20,840)	(21,136)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$151,357	$151,061	$150,765	$150,469	$150,173	$149,877	$149,581	$149,285	$148,989	$148,693	$148,397	$148,101	$147,805	
6	Average Net Investment			151,209	150,913	150,617	150,321	150,025	149,729	149,433	149,137	148,841	148,545	148,249	147,953	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		372	371	371	370	369	368	368	367	366	365	365	364	$4,416
	b. Equity Component Grossed Up For Taxes	8.02%		1,011	1,009	1,007	1,005	1,003	1,001	999	997	995	993	991	989	12,000
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.10%		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007910		111	111	111	111	111	111	111	111	111	111	111	111	1,332
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,790	1,787	1,785	1,782	1,779	1,776	1,774	1,771	1,768	1,765	1,763	1,760	21,300
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,790	1,787	1,785	1,782	1,779	1,776	1,774	1,771	1,768	1,765	1,763	1,760	21,300
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			1,661	1,658	1,656	1,654	1,651	1,648	1,646	1,643	1,641	1,638	1,636	1,633	19,765
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,661	$1,658	$1,656	$1,654	$1,651	$1,648	$1,646	$1,643	$1,641	$1,638	$1,636	$1,633	$19,765

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc Tax multiplier = 1.628002). Based on 2010 rate case Oder PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation	(9,605)	(9,808)	(10,011)	(10,214)	(10,417)	(10,620)	(10,823)	(11,026)	(11,229)	(11,432)	(11,635)	(11,838)	(12,041)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$66,401	$66,198	$65,995	$65,792	$65,589	$65,386	$65,183	$64,980	$64,777	$64,574	$64,371	$64,168	$63,965	
6	Average Net Investment		66,300	66,097	65,894	65,691	65,488	65,285	65,082	64,879	64,676	64,473	64,270	64,067	
7	Return on Average Net Investment (B)														
	a. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		163	163	162	162	161	161	160	160	159	159	158	158	1,926
	b. Equity Component Grossed Up For Taxes 8.02%		443	442	441	439	438	437	435	434	432	431	430	428	5,230
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.20%		203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.009370		59	59	59	59	59	59	59	59	59	59	59	59	708
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		868	867	865	863	861	860	857	856	853	852	850	848	10,300
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		868	867	865	863	861	860	857	856	853	852	850	848	10,300
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)		0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)		630	629	627	626	625	624	622	621	619	618	617	615	7,472
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$630	$629	$627	$626	$625	$624	$622	$621	$619	$618	$617	$615	$7,472

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: MODULAR COOLING TOWERS - Base (Project 11)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	
3	Less: Accumulated Depreciation		(590,211)	(601,297)	(612,383)	(623,469)	(634,555)	(645,641)	(656,727)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$74,929	$63,843	$52,757	$41,671	$30,585	$19,499	$8,413	$0	$0	$0	$0	$0	$0	
6	Average Net Investment			69,386	58,300	47,214	36,128	25,042	13,956	4,207	0	0	0	0	0	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		171	143	116	89	62	34	10	0	0	0	0	0	625
	b. Equity Component Grossed Up For Taxes	8.02%		464	390	316	242	167	93	28	0	0	0	0	0	1,700
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	20.00%		11,086	11,086	11,086	11,086	11,086	11,086	8,413	0	0	0	0	0	74,929
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007910		438	438	438	438	438	438	438	438	438	438	438	438	5,256
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			12,159	12,057	11,956	11,855	11,753	11,651	8,889	438	438	438	438	438	82,510
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			12,159	12,057	11,956	11,855	11,753	11,651	8,889	438	438	438	438	438	82,510
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			11,283	11,188	11,094	11,000	10,906	10,811	8,248	406	406	406	406	406	76,563
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$11,283	$11,188	$11,094	$11,000	$10,906	$10,811	$8,248	$406	$406	$406	$406	$406	$76,563

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 060162-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CRYSTAL RIVER THERMAL DISCHARGE COMPLIANCE PROJECT - AFUDC - Base (Project 11.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			($633,112)	$6,795	$308,002	$20,118	$12,435	$9,195	$30,394	$27,240	$2,619	$1,090	$23,478	($280,979)	($472,726)
	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	
	d. Other (A)			85,539	92,074	93,858	95,352	96,041	96,710	68,688	98,084	98,825	99,519	100,125	100,746	
2	Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation		(8,578)	(9,090)	(9,602)	(10,114)	(10,626)	(11,138)	(11,650)	(12,162)	(12,674)	(13,186)	(13,698)	(14,210)	(14,722)	
4	CWIP - AFUDC Bearing		15,421,367	14,873,794	14,972,663	15,374,523	15,489,992	15,598,468	15,704,373	15,803,454	15,928,778	16,030,222	16,130,831	16,254,434	16,074,201	
5	Net Investment (Lines 2 + 3 + 4)		$15,774,525	$15,226,440	$15,324,796	$15,726,144	$15,841,102	$15,949,066	$16,054,458	$16,153,028	$16,277,840	$16,378,772	$16,478,869	$16,601,960	$16,421,214	
6	Average Net Investment (B)			$352,902	$352,390	$351,878	$351,366	$350,854	$350,342	$349,830	$349,318	$348,806	$348,294	$347,782	$347,270	
7	Return on Average Net Investment (C)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		868	867	866	864	863	862	861	859	858	857	856	854	10,335
	b. Equity Component Grossed Up For Taxes	8.02%		2,360	2,356	2,353	2,349	2,346	2,342	2,339	2,336	2,332	2,329	2,325	2,322	28,089
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (D)			512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	N/A
	d. Property Taxes (E)	0.007910		295	295	295	295	295	295	295	295	295	295	295	295	3,540
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (F)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (G)			3,744	3,740	3,736	3,730	3,727	3,722	3,718	3,714	3,709	3,705	3,701	3,696	44,640
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$3,744	$3,740	$3,736	$3,730	$3,727	$3,722	$3,718	$3,714	$3,709	$3,705	$3,701	$3,696	$44,640

Notes:

(A) AFUDC rate reflected within Docket 100134-EI per Order PSC-10-0604-PAA-EI.
(B) Line represents the Average Net Investment excluding AFUDC interest-bearing CWIP projects. Refer to Capital Program Detail for Average Net Investment Return on which Line 7 is calculated.
(C) Weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Depreciation calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: NPDES - Bartow Freeboard (Project 16)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Actual July 11	Actual August 11	Actual September 11	Actual October 11	Actual November 11	Actual December 11	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$60,051	$0	$ 60,051
	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	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	60,051	60,051	
5	Net Investment (Lines 2 + 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$60,051	$60,051	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	30,026	60,051	
7	Return on Average Net Investment (B)														
	a. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		0	0	0	0	0	0	0	0	0	0	74	148	222
	b. Equity Component Grossed Up For Taxes 8.02%		0	0	0	0	0	0	0	0	0	0	201	402	603
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.30%		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. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.009370		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	275	550	825
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	275	550	825
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)		0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	255	510	766
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 255	$ 510	$ 766

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-Up Amount
January 2011 through December 2011

Form 42 9A

Capital Structure and Cost Rates

Tax Rate
38.575%

Class of Capital	Retail Amount	Staff Adjusted	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$ 2,916,026	$ 2,945,782	46.74%	0.10500	4.908%	7.990%
PS	21,239	21,456	0.34%	0.04510	0.015%	0.025%
LTD	2,817,708	2,846,460	45.17%	0.06178	2.790%	2.790%
STD	41,245	41,666	0.66%	0.03720	0.025%	0.025%
CD-Active	144,119	145,590	2.31%	0.05950	0.137%	0.137%
CD-Inactive	1,457	1,472	0.02%	0.00000	0.000%	0.000%
ADIT	415,881	420,125	6.67%	0.00000	0.000%	0.000%
FAS 109	(122,914)	(124,168)	-1.97%	0.00000	0.000%	0.000%
ITC	3,857	3,896	0.06%	0.08360	0.005%	0.008%
Total	$ 6,238,618	$ 6,302,278	100.00%		7.881%	10.976%
				Total Debt	2.952%	2.952%
				Total Equity	4.928%	8.023%

Source: Per Staff 13-Month Average Capital Structure worksheet - Schedule 2 REVISED - handed out at 1/11/10 Rate Case Agenda - Docket No. 090079-EI.

Rationale: PEF is using the currently approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause
Capital Programs Detail

January 2011 - December 2011
Final True-Up
Docket No. 120007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI **EXHIBIT** 27
PARTY Progress Energy Florida
DESCRIPTION Will Garrett (WG-2), Capital Program Detail
DATE January 1/11 - 12/11

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	
3	Less: Accumulated Depreciation		(6,145)	(6,199)	(6,253)	(6,307)	(6,361)	(6,415)	(6,469)	(6,523)	(6,577)	(6,631)	(6,685)	(6,739)	(6,793)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$27,808	$27,754	$27,700	$27,646	$27,592	$27,538	$27,484	$27,430	$27,376	$27,322	$27,268	$27,214	$27,160	
6	Average Net Investment			27,781	27,727	27,673	27,619	27,565	27,511	27,457	27,403	27,349	27,295	27,241	27,187	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		68	68	68	68	68	68	68	67	67	67	67	67	811
	b. Equity Component Grossed Up For Taxes	8.02%		186	185	185	185	184	184	184	183	183	182	182	182	2,205
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.90%		54	54	54	54	54	54	54	54	54	54	54	54	648
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		26	26	26	26	26	26	26	26	26	26	26	26	312
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$334	$333	$333	$333	$332	$332	$332	$330	$330	$329	$329	$329	$3,976
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$334	$333	$333	$333	$332	$332	$332	$330	$330	$329	$329	$329	$3,976

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	$2,640,636	
3	Less: Accumulated Depreciation		(590,327)	(596,048)	(601,769)	(607,490)	(613,211)	(618,932)	(624,653)	(630,374)	(636,095)	(641,816)	(647,537)	(653,258)	(658,979)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,050,309	$2,044,588	$2,038,867	$2,033,146	$2,027,425	$2,021,704	$2,015,983	$2,010,262	$2,004,541	$1,998,820	$1,993,099	$1,987,378	$1,981,657	
6	Average Net Investment			2,047,449	2,041,728	2,036,007	2,030,286	2,024,565	2,018,844	2,013,123	2,007,402	2,001,681	1,995,960	1,990,239	1,984,518	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		5,037	5,023	5,009	4,995	4,981	4,967	4,953	4,939	4,925	4,911	4,897	4,883	59,520
	b. Equity Component Grossed Up For Taxes	8.02%		13,690	13,651	13,613	13,575	13,537	13,498	13,460	13,422	13,384	13,345	13,307	13,269	161,751
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	68,652
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	24,348
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$26,477	$26,424	$26,372	$26,320	$26,268	$26,215	$26,163	$26,111	$26,059	$26,006	$25,954	$25,902	$314,271
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$26,477	$26,424	$26,372	$26,320	$26,268	$26,215	$26,163	$26,111	$26,059	$26,006	$25,954	$25,902	$314,271

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$4,259	$0	$0	$0	$0	$0	$0	$0	$4,259
	b. Clearings to Plant			0	0	0	0	4,259	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$905,147	$905,147	$905,147	$905,147	$905,147	$909,407	$909,407	$909,407	$909,407	$909,407	$909,407	$909,407	$909,407	
3	Less: Accumulated Depreciation		(61,768)	(63,729)	(65,690)	(67,651)	(69,612)	(71,582)	(73,552)	(75,522)	(77,492)	(79,462)	(81,432)	(83,402)	(85,372)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$843,379	$841,418	$839,457	$837,496	$835,535	$837,824	$835,854	$833,884	$831,914	$829,944	$827,974	$826,004	$824,034	
6	Average Net Investment			842,399	840,438	838,477	836,516	836,680	836,839	834,869	832,899	830,929	828,959	826,989	825,019	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,073	2,068	2,063	2,058	2,058	2,059	2,054	2,049	2,044	2,039	2,035	2,030	24,630
	b. Equity Component Grossed Up For Taxes	8.02%		5,632	5,619	5,606	5,593	5,594	5,595	5,582	5,569	5,556	5,543	5,529	5,516	66,934
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		1,961	1,961	1,961	1,961	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	23,604
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		695	695	695	695	699	699	699	699	699	699	699	699	8,372
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$10,361	$10,343	$10,325	$10,307	$10,321	$10,323	$10,305	$10,287	$10,269	$10,251	$10,233	$10,215	$123,540
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$10,361	$10,343	$10,325	$10,307	$10,321	$10,323	$10,305	$10,287	$10,269	$10,251	$10,233	$10,215	$123,540

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$31,250	$31,260	$40	$0	$0	$0	$31,534	$40,984	$135,068
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	135,068	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$135,068	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(192)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	31,250	62,510	62,550	62,550	62,550	62,550	94,084	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	$0	$0	$0	$0	$31,250	$62,510	$62,550	$62,550	$62,550	$62,550	$94,084	$134,876	
6	Average Net Investment			0	0	0	0	15,625	46,880	62,530	62,550	62,550	62,550	78,317	114,480	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	38	115	154	154	154	154	193	282	1,244
	b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	104	313	418	418	418	418	524	765	3,378
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.40%		0	0	0	0	0	0	0	0	0	0	0	192	192
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		0	0	0	0	0	0	0	0	0	0	0	104	104
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$0	$0	$0	$0	$142	$428	$572	$572	$572	$572	$717	$1,343	$4,918
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$142	$428	$572	$572	$572	$572	$717	$1,343	$4,918

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$14,528	$0	$0	$0	$0	$0	$0	$0	$14,528
	b. Clearings to Plant			0	0	0	0	14,528	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$2,052,071	$2,052,071	$2,052,071	$2,052,071	$2,052,071	$2,066,599	$2,066,599	$2,066,599	$2,066,599	$2,066,599	$2,066,599	$2,066,599	$2,066,599	
3	Less: Accumulated Depreciation		(96,747)	(101,834)	(106,921)	(112,008)	(117,095)	(122,218)	(127,341)	(132,464)	(137,587)	(142,710)	(147,833)	(152,956)	(158,079)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,955,324	$1,950,238	$1,945,151	$1,940,064	$1,934,977	$1,944,381	$1,939,258	$1,934,135	$1,929,012	$1,923,889	$1,918,766	$1,913,643	$1,908,520	
6	Average Net Investment			1,952,781	1,947,694	1,942,607	1,937,520	1,939,679	1,941,820	1,936,697	1,931,574	1,926,451	1,921,328	1,916,205	1,911,082	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,804	4,792	4,779	4,767	4,772	4,777	4,765	4,752	4,740	4,727	4,714	4,702	57,091
	b. Equity Component Grossed Up For Taxes	8.02%		13,057	13,023	12,989	12,955	12,969	12,983	12,949	12,915	12,881	12,846	12,812	12,778	155,157
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.98%		5,087	5,087	5,087	5,087	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,332
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010850		1,855	1,855	1,855	1,855	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	22,372
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$24,803	$24,757	$24,710	$24,664	$24,733	$24,752	$24,706	$24,659	$24,613	$24,565	$24,518	$24,472	$295,952
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$24,803	$24,757	$24,710	$24,664	$24,733	$24,752	$24,706	$24,659	$24,613	$24,565	$24,518	$24,472	$295,952

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	
3	Less: Accumulated Depreciation		(71,451)	(75,136)	(78,821)	(82,506)	(86,191)	(89,876)	(93,561)	(97,246)	(100,931)	(104,616)	(108,301)	(111,986)	(115,671)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,402,350	$1,398,665	$1,394,980	$1,391,295	$1,387,610	$1,383,925	$1,380,240	$1,376,555	$1,372,870	$1,369,185	$1,365,500	$1,361,815	$1,358,130	
6	Average Net Investment			1,400,508	1,396,823	1,393,138	1,389,453	1,385,768	1,382,083	1,378,398	1,374,713	1,371,028	1,367,343	1,363,658	1,359,973	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		3,446	3,437	3,428	3,418	3,409	3,400	3,391	3,382	3,373	3,364	3,355	3,346	40,749
	b. Equity Component Grossed Up For Taxes	8.02%		9,364	9,339	9,315	9,290	9,265	9,241	9,216	9,192	9,167	9,142	9,118	9,093	110,742
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	13,812
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$17,646	$17,612	$17,579	$17,544	$17,510	$17,477	$17,443	$17,410	$17,376	$17,342	$17,309	$17,275	$209,523
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$17,646	$17,612	$17,579	$17,544	$17,510	$17,477	$17,443	$17,410	$17,376	$17,342	$17,309	$17,275	$209,523

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	
3	Less: Accumulated Depreciation		(285,791)	(294,930)	(304,069)	(313,208)	(322,347)	(331,486)	(340,625)	(349,764)	(358,903)	(368,042)	(377,181)	(386,320)	(395,459)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,375,873	$1,366,734	$1,357,595	$1,348,456	$1,339,317	$1,330,178	$1,321,039	$1,311,900	$1,302,761	$1,293,622	$1,284,483	$1,275,344	$1,266,205	
6	Average Net Investment			1,371,304	1,362,165	1,353,026	1,343,887	1,334,748	1,325,609	1,316,470	1,307,331	1,298,192	1,289,053	1,279,914	1,270,775	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		3,374	3,351	3,329	3,306	3,284	3,261	3,239	3,216	3,194	3,171	3,149	3,127	39,001
	b. Equity Component Grossed Up For Taxes	8.02%		9,169	9,108	9,047	8,985	8,924	8,863	8,802	8,741	8,680	8,619	8,558	8,497	105,993
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.60%		9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008880		1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	14,760
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$22,912	$22,828	$22,745	$22,660	$22,577	$22,493	$22,410	$22,326	$22,243	$22,159	$22,076	$21,993	$269,422
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$22,912	$22,828	$22,745	$22,660	$22,577	$22,493	$22,410	$22,326	$22,243	$22,159	$22,076	$21,993	$269,422

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	
3	Less: Accumulated Depreciation		(29,753)	(30,469)	(31,185)	(31,901)	(32,617)	(33,333)	(34,049)	(34,765)	(35,481)	(36,197)	(36,913)	(37,629)	(38,345)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$149,185	$148,469	$147,753	$147,037	$146,321	$145,605	$144,889	$144,173	$143,457	$142,741	$142,025	$141,309	$140,593	
6	Average Net Investment			148,827	148,111	147,395	146,679	145,963	145,247	144,531	143,815	143,099	142,383	141,667	140,951	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		366	364	363	361	359	357	356	354	352	350	349	347	4,278
	b. Equity Component Grossed Up For Taxes	8.02%		995	990	986	981	976	971	966	962	957	952	947	942	11,625
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.80%		716	716	716	716	716	716	716	716	716	716	716	716	8,592
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008940		133	133	133	133	133	133	133	133	133	133	133	133	1,596
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$2,210	$2,203	$2,198	$2,191	$2,184	$2,177	$2,171	$2,165	$2,158	$2,151	$2,145	$2,138	$26,091
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$2,210	$2,203	$2,198	$2,191	$2,184	$2,177	$2,171	$2,165	$2,158	$2,151	$2,145	$2,138	$26,091

PROGRESS ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	
3	Less: Accumulated Depreciation		(67,508)	(69,334)	(71,160)	(72,986)	(74,812)	(76,638)	(78,464)	(80,290)	(82,116)	(83,942)	(85,768)	(87,594)	(89,420)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$662,787	$660,961	$659,135	$657,309	$655,483	$653,657	$651,831	$650,005	$648,179	$646,353	$644,527	$642,701	$640,875	
6	Average Net Investment			661,874	660,048	658,222	656,396	654,570	652,744	650,918	649,092	647,266	645,440	643,614	641,788	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,628	1,624	1,619	1,615	1,610	1,606	1,601	1,597	1,592	1,588	1,583	1,579	19,242
	b. Equity Component Grossed Up For Taxes	8.02%		4,425	4,413	4,401	4,389	4,377	4,364	4,352	4,340	4,328	4,316	4,303	4,291	52,299
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	21,912
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		570	570	570	570	570	570	570	570	570	570	570	570	6,840
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$8,449	$8,433	$8,416	$8,400	$8,383	$8,366	$8,349	$8,333	$8,316	$8,300	$8,282	$8,266	$100,293
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$8,449	$8,433	$8,416	$8,400	$8,383	$8,366	$8,349	$8,333	$8,316	$8,300	$8,282	$8,266	$100,293

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	
3	Less: Accumulated Depreciation		(118,584)	(121,436)	(124,288)	(127,140)	(129,992)	(132,844)	(135,696)	(138,548)	(141,400)	(144,252)	(147,104)	(149,956)	(152,808)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$918,615	$915,763	$912,911	$910,059	$907,207	$904,355	$901,503	$898,651	$895,799	$892,947	$890,095	$887,243	$884,391	
6	Average Net Investment			917,189	914,337	911,485	908,633	905,781	902,929	900,077	897,225	894,373	891,521	888,669	885,817	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,257	2,250	2,243	2,236	2,229	2,221	2,214	2,207	2,200	2,193	2,186	2,179	26,615
	b. Equity Component Grossed Up For Taxes	8.02%		6,132	6,113	6,094	6,075	6,056	6,037	6,018	5,999	5,980	5,961	5,942	5,923	72,330
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.30%		2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007670		663	663	663	663	663	663	663	663	663	663	663	663	7,956
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$11,904	$11,878	$11,852	$11,826	$11,800	$11,773	$11,747	$11,721	$11,695	$11,669	$11,643	$11,617	$141,125
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$11,904	$11,878	$11,852	$11,826	$11,800	$11,773	$11,747	$11,721	$11,695	$11,669	$11,643	$11,617	$141,125

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$6,710	$23,150	$9,108	$9,543	$10,474	$331,969	$217,248	$242,705	($5,057)	$371,492	$1,217,343
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	1,217,343	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$2,394,294	$2,394,294	$2,394,294	$2,394,294	$2,394,294	$2,394,294	$2,394,294	$2,394,294	$2,394,294	$2,394,294	$2,394,294	$2,394,294	$3,611,636	
3	Less: Accumulated Depreciation		(100,278)	(105,466)	(110,654)	(115,842)	(121,030)	(126,218)	(131,406)	(136,594)	(141,782)	(146,970)	(152,158)	(157,346)	(163,852)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	6,709	29,859	38,968	48,511	58,985	390,954	608,202	850,907	845,850	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$2,294,016	$2,288,828	$2,283,640	$2,285,161	$2,303,123	$2,307,044	$2,311,399	$2,316,685	$2,643,466	$2,855,526	$3,093,043	$3,082,798	$3,447,785	
6	Average Net Investment			2,291,422	2,286,234	2,284,401	2,294,142	2,305,084	2,309,221	2,314,042	2,480,076	2,749,496	2,974,285	3,087,921	3,265,292	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		5,638	5,625	5,620	5,644	5,671	5,681	5,693	6,102	6,765	7,318	7,597	8,034	75,388
	b. Equity Component Grossed Up For Taxes	8.02%		15,321	15,286	15,274	15,339	15,412	15,440	15,472	16,582	18,384	19,887	20,646	21,832	204,875
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	6,506	63,574
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010850		2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	3,266	27,081
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$28,312	$28,264	$28,247	$28,336	$28,436	$28,474	$28,518	$30,037	$32,502	$34,558	$35,596	$39,638	$370,918
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$28,312	$28,264	$28,247	$28,336	$28,436	$28,474	$28,518	$30,037	$32,502	$34,558	$35,596	$39,638	$370,918

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	
3	Less: Accumulated Depreciation		(40,158)	(40,394)	(40,630)	(40,866)	(41,102)	(41,338)	(41,574)	(41,810)	(42,046)	(42,282)	(42,518)	(42,754)	(42,990)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$101,276	$101,040	$100,804	$100,568	$100,332	$100,096	$99,860	$99,624	$99,388	$99,152	$98,916	$98,680	$98,444	
6	Average Net Investment			101,158	100,922	100,686	100,450	100,214	99,978	99,742	99,506	99,270	99,034	98,798	98,562	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		249	248	248	247	247	246	245	245	244	244	243	242	2,948
	b. Equity Component Grossed Up For Taxes	8.02%		676	675	673	672	670	668	667	665	664	662	661	659	8,012
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.00%		236	236	236	236	236	236	236	236	236	236	236	236	2,832
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.014400		170	170	170	170	170	170	170	170	170	170	170	170	2,040
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,331	$1,329	$1,327	$1,325	$1,323	$1,320	$1,318	$1,316	$1,314	$1,312	$1,310	$1,307	$15,832
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,331	$1,329	$1,327	$1,325	$1,323	$1,320	$1,318	$1,316	$1,314	$1,312	$1,310	$1,307	$15,832

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	
3	Less: Accumulated Depreciation		(33,120)	(34,897)	(36,674)	(38,451)	(40,228)	(42,005)	(43,782)	(45,559)	(47,336)	(49,113)	(50,890)	(52,667)	(54,444)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$361,848	$360,071	$358,294	$356,517	$354,740	$352,963	$351,186	$349,409	$347,632	$345,855	$344,078	$342,301	$340,524	
6	Average Net Investment			360,959	359,182	357,405	355,628	353,851	352,074	350,297	348,520	346,743	344,966	343,189	341,412	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		888	884	879	875	871	866	862	857	853	849	844	840	10,368
	b. Equity Component Grossed Up For Taxes	8.02%		2,413	2,402	2,390	2,378	2,366	2,354	2,342	2,330	2,318	2,307	2,295	2,283	28,178
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.40%		1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	21,324
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		308	308	308	308	308	308	308	308	308	308	308	308	3,696
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$5,386	$5,371	$5,354	$5,338	$5,322	$5,305	$5,289	$5,272	$5,256	$5,241	$5,224	$5,208	$63,566
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$5,386	$5,371	$5,354	$5,338	$5,322	$5,305	$5,289	$5,272	$5,256	$5,241	$5,224	$5,208	$63,566

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	
3	Less: Accumulated Depreciation		(9,771)	(9,873)	(9,975)	(10,077)	(10,179)	(10,281)	(10,383)	(10,485)	(10,587)	(10,689)	(10,791)	(10,893)	(10,995)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$23,321	$23,219	$23,117	$23,015	$22,913	$22,811	$22,709	$22,607	$22,505	$22,403	$22,301	$22,199	$22,097	
6	Average Net Investment			23,270	23,168	23,066	22,964	22,862	22,760	22,658	22,556	22,454	22,352	22,250	22,148	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		57	57	57	56	56	56	56	55	55	55	55	54	669
	b. Equity Component Grossed Up For Taxes	8.02%		156	155	154	154	153	152	151	151	150	149	149	148	1,822
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.70%		102	102	102	102	102	102	102	102	102	102	102	102	1,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		22	22	22	22	22	22	22	22	22	22	22	22	264
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$337	$336	$335	$334	$333	$332	$331	$330	$329	$328	$328	$326	$3,979
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$337	$336	$335	$334	$333	$332	$331	$330	$329	$328	$328	$326	$3,979

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$7,706	$0	($3,398)	$0	$4,153	$0	$0	$0	$0	$0	$0	$0	$8,461
	b. Clearings to Plant			7,706	0	(3,398)	0	4,153	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$2,844,718	$2,852,424	$2,852,424	$2,849,026	$2,849,026	$2,853,179	$2,853,179	$2,853,179	$2,853,179	$2,853,179	$2,853,179	$2,853,179	$2,853,179	
3	Less: Accumulated Depreciation		(133,555)	(139,498)	(145,441)	(151,376)	(157,311)	(163,255)	(169,199)	(175,143)	(181,087)	(187,031)	(192,975)	(198,919)	(204,863)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,711,164	$2,712,927	$2,706,984	$2,697,651	$2,691,716	$2,689,924	$2,683,980	$2,678,036	$2,672,092	$2,666,148	$2,660,204	$2,654,260	$2,648,316	
6	Average Net Investment			2,712,045	2,709,955	2,702,317	2,694,683	2,690,820	2,686,952	2,681,008	2,675,064	2,669,120	2,663,176	2,657,232	2,651,288	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		6,672	6,667	6,649	6,630	6,620	6,611	6,596	6,581	6,567	6,552	6,538	6,523	79,206
	b. Equity Component Grossed Up For Taxes	8.02%		18,133	18,119	18,068	18,017	17,991	17,965	17,926	17,886	17,846	17,806	17,767	17,727	215,251
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		5,943	5,943	5,935	5,935	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	71,308
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		1,880	1,880	1,878	1,878	1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,881	22,564
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$32,628	$32,609	$32,530	$32,460	$32,436	$32,401	$32,347	$32,292	$32,238	$32,183	$32,130	$32,075	$388,329
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$32,628	$32,609	$32,530	$32,460	$32,436	$32,401	$32,347	$32,292	$32,238	$32,183	$32,130	$32,075	$388,329

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	
3	Less: Accumulated Depreciation		(28,602)	(29,134)	(29,666)	(30,198)	(30,730)	(31,262)	(31,794)	(32,326)	(32,858)	(33,390)	(33,922)	(34,454)	(34,986)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$261,696	$261,164	$260,632	$260,100	$259,568	$259,036	$258,504	$257,972	$257,440	$256,908	$256,376	$255,844	$255,312	
6	Average Net Investment			261,430	260,898	260,366	259,834	259,302	258,770	258,238	257,706	257,174	256,642	256,110	255,578	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		643	642	641	639	638	637	635	634	633	631	630	629	7,632
	b. Equity Component Grossed Up For Taxes	8.02%		1,748	1,744	1,741	1,737	1,734	1,730	1,727	1,723	1,720	1,716	1,712	1,709	20,741
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.20%		532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008000		194	194	194	194	194	194	194	194	194	194	194	194	2,328
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,117	$3,112	$3,108	$3,102	$3,098	$3,093	$3,088	$3,083	$3,079	$3,073	$3,068	$3,064	$37,085
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$3,117	$3,112	$3,108	$3,102	$3,098	$3,093	$3,088	$3,083	$3,079	$3,073	$3,068	$3,064	$37,085

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	
3	Less: Accumulated Depreciation		(9,401)	(9,805)	(10,209)	(10,613)	(11,017)	(11,421)	(11,825)	(12,229)	(12,633)	(13,037)	(13,441)	(13,845)	(14,249)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$152,353	$151,949	$151,545	$151,141	$150,737	$150,333	$149,929	$149,525	$149,121	$148,717	$148,313	$147,909	$147,505	
6	Average Net Investment			152,151	151,747	151,343	150,939	150,535	150,131	149,727	149,323	148,919	148,515	148,111	147,707	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		374	373	372	371	370	369	368	367	366	365	364	363	4,422
	b. Equity Component Grossed Up For Taxes	8.02%		1,017	1,015	1,012	1,009	1,007	1,004	1,001	998	996	993	990	988	12,030
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		404	404	404	404	404	404	404	404	404	404	404	404	4,848
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008940		121	121	121	121	121	121	121	121	121	121	121	121	1,452
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,916	$1,913	$1,909	$1,905	$1,902	$1,898	$1,894	$1,890	$1,887	$1,883	$1,879	$1,876	$22,752
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,916	$1,913	$1,909	$1,905	$1,902	$1,898	$1,894	$1,890	$1,887	$1,883	$1,879	$1,876	$22,752

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	
3	Less: Accumulated Depreciation		(23,677)	(24,044)	(24,411)	(24,778)	(25,145)	(25,512)	(25,879)	(26,246)	(26,613)	(26,980)	(27,347)	(27,714)	(28,081)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$251,670	$251,303	$250,936	$250,569	$250,202	$249,835	$249,468	$249,101	$248,734	$248,367	$248,000	$247,633	$247,266	
6	Average Net Investment			251,487	251,120	250,753	250,386	250,019	249,652	249,285	248,918	248,551	248,184	247,817	247,450	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		619	618	617	616	615	614	613	612	612	611	610	609	7,366
	b. Equity Component Grossed Up For Taxes	8.02%		1,681	1,679	1,677	1,674	1,672	1,669	1,667	1,664	1,662	1,659	1,657	1,654	20,015
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.60%		367	367	367	367	367	367	367	367	367	367	367	367	4,404
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		215	215	215	215	215	215	215	215	215	215	215	215	2,580
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$2,882	$2,879	$2,876	$2,872	$2,869	$2,865	$2,862	$2,858	$2,856	$2,852	$2,849	$2,845	$34,365
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$2,882	$2,879	$2,876	$2,872	$2,869	$2,865	$2,862	$2,858	$2,856	$2,852	$2,849	$2,845	$34,365

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR CTs (Project 7.2 Recap)

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For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$198,988	$198,988	$198,988	$198,988	$198,988	$198,988	$198,988	$198,988	$198,988	$198,988	$198,988	$198,988	$198,988	
3	Less: Accumulated Depreciation		(15,651)	(16,032)	(16,413)	(16,794)	(17,175)	(17,556)	(17,937)	(18,318)	(18,699)	(19,080)	(19,461)	(19,842)	(20,223)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$183,337	$182,956	$182,575	$182,194	$181,813	$181,432	$181,051	$180,670	$180,289	$179,908	$179,527	$179,146	$178,765	
6	Average Net Investment			183,147	182,766	182,385	182,004	181,623	181,242	180,861	180,480	180,099	179,718	179,337	178,956	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		451	450	449	448	447	446	445	444	443	442	441	440	5,346
	b. Equity Component Grossed Up For Taxes	8.02%		1,225	1,222	1,219	1,217	1,214	1,212	1,209	1,207	1,204	1,202	1,199	1,197	14,527
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.30%		381	381	381	381	381	381	381	381	381	381	381	381	4,572
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		155	155	155	155	155	155	155	155	155	155	155	155	1,860
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$2,212	$2,208	$2,204	$2,201	$2,197	$2,194	$2,190	$2,187	$2,183	$2,180	$2,176	$2,173	$26,305
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$2,212	$2,208	$2,204	$2,201	$2,197	$2,194	$2,190	$2,187	$2,183	$2,180	$2,176	$2,173	$26,305

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$87,667	$87,667	$87,667	$87,667	$87,667	$87,667	$87,667	$87,667	$87,667	$87,667	$87,667	$87,667	$87,667	
3	Less: Accumulated Depreciation		(9,003)	(9,222)	(9,441)	(9,660)	(9,879)	(10,098)	(10,317)	(10,536)	(10,755)	(10,974)	(11,193)	(11,412)	(11,631)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$78,664	$78,445	$78,226	$78,007	$77,788	$77,569	$77,350	$77,131	$76,912	$76,693	$76,474	$76,255	$76,036	
6	Average Net Investment			78,554	78,335	78,116	77,897	77,678	77,459	77,240	77,021	76,802	76,583	76,364	76,145	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		193	193	192	192	191	191	190	189	189	188	188	187	2,283
	b. Equity Component Grossed Up For Taxes	8.02%		525	524	522	521	519	518	516	515	514	512	511	509	6,206
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010850		79	79	79	79	79	79	79	79	79	79	79	79	948
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,016	$1,015	$1,012	$1,011	$1,008	$1,007	$1,004	$1,002	$1,001	$998	$997	$994	$12,065
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,016	$1,015	$1,012	$1,011	$1,008	$1,007	$1,004	$1,002	$1,001	$998	$997	$994	$12,065

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$1,708	$0	$0	$0	$0	$0	$0	$0	$1,708
	b. Clearings to Plant			0	0	0	0	1,708	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$345,490	$345,490	$345,490	$345,490	$345,490	$347,198	$347,198	$347,198	$347,198	$347,198	$347,198	$347,198	$347,198	
3	Less: Accumulated Depreciation		(16,717)	(17,552)	(18,387)	(19,222)	(20,057)	(20,896)	(21,735)	(22,574)	(23,413)	(24,252)	(25,091)	(25,930)	(26,769)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$328,773	$327,938	$327,103	$326,268	$325,433	$326,302	$325,463	$324,624	$323,785	$322,946	$322,107	$321,268	$320,429	
6	Average Net Investment			328,356	327,521	326,686	325,851	325,868	325,882	325,043	324,204	323,365	322,526	321,687	320,848	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		808	806	804	802	802	802	800	798	796	794	791	789	9,592
	b. Equity Component Grossed Up For Taxes	8.02%		2,195	2,190	2,184	2,179	2,179	2,179	2,173	2,168	2,162	2,156	2,151	2,145	26,061
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.90%		835	835	835	835	839	839	839	839	839	839	839	839	10,052
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		270	270	270	270	271	271	271	271	271	271	271	271	3,248
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$4,108	$4,101	$4,093	$4,086	$4,091	$4,091	$4,083	$4,076	$4,068	$4,060	$4,052	$4,044	$48,953
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$4,108	$4,101	$4,093	$4,086	$4,091	$4,091	$4,083	$4,076	$4,068	$4,060	$4,052	$4,044	$48,953

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$349,583	$349,583	$349,583	$349,583	$349,583	$349,583	$349,583	$349,583	$349,583	$349,583	$349,583	$349,583	$349,583	
3	Less: Accumulated Depreciation		(28,903)	(29,690)	(30,477)	(31,264)	(32,051)	(32,838)	(33,625)	(34,412)	(35,199)	(35,986)	(36,773)	(37,560)	(38,347)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$320,681	$319,894	$319,107	$318,320	$317,533	$316,746	$315,959	$315,172	$314,385	$313,598	$312,811	$312,024	$311,237	
6	Average Net Investment			320,287	319,500	318,713	317,926	317,139	316,352	315,565	314,778	313,991	313,204	312,417	311,630	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		788	786	784	782	780	778	776	774	773	771	769	767	9,328
	b. Equity Component Grossed Up For Taxes	8.02%		2,141	2,136	2,131	2,126	2,120	2,115	2,110	2,105	2,099	2,094	2,089	2,084	25,350
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.70%		787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008880		259	259	259	259	259	259	259	259	259	259	259	259	3,108
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,975	$3,968	$3,961	$3,954	$3,946	$3,939	$3,932	$3,925	$3,918	$3,911	$3,904	$3,897	$47,230
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$3,975	$3,968	$3,961	$3,954	$3,946	$3,939	$3,932	$3,925	$3,918	$3,911	$3,904	$3,897	$47,230

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$134,012	$134,012	$134,012	$134,012	$134,012	$134,012	$134,012	$134,012	$134,012	$134,012	$134,012	$134,012	$134,012	
3	Less: Accumulated Depreciation		(9,375)	(9,509)	(9,643)	(9,777)	(9,911)	(10,045)	(10,179)	(10,313)	(10,447)	(10,581)	(10,715)	(10,849)	(10,983)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$124,637	$124,503	$124,369	$124,235	$124,101	$123,967	$123,833	$123,699	$123,565	$123,431	$123,297	$123,163	$123,029	
6	Average Net Investment			124,570	124,436	124,302	124,168	124,034	123,900	123,766	123,632	123,498	123,364	123,230	123,096	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		306	306	306	305	305	305	305	304	304	304	303	303	3,656
	b. Equity Component Grossed Up For Taxes	8.02%		833	832	831	830	829	828	828	827	826	825	824	823	9,936
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.20%		134	134	134	134	134	134	134	134	134	134	134	134	1,608
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010850		121	121	121	121	121	121	121	121	121	121	121	121	1,452
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,394	$1,393	$1,392	$1,390	$1,389	$1,388	$1,388	$1,386	$1,385	$1,384	$1,382	$1,381	$16,652
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,394	$1,393	$1,392	$1,390	$1,389	$1,388	$1,388	$1,386	$1,385	$1,384	$1,382	$1,381	$16,652

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$381,560	$381,560	$381,560	$381,560	$381,560	$381,560	$381,560	$381,560	$381,560	$381,560	$381,560	$381,560	$381,560	
3	Less: Accumulated Depreciation		(20,778)	(21,191)	(21,604)	(22,017)	(22,430)	(22,843)	(23,256)	(23,669)	(24,082)	(24,495)	(24,908)	(25,321)	(25,734)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$360,782	$360,369	$359,956	$359,543	$359,130	$358,717	$358,304	$357,891	$357,478	$357,065	$356,652	$356,239	$355,826	
6	Average Net Investment			360,575	360,162	359,749	359,336	358,923	358,510	358,097	357,684	357,271	356,858	356,445	356,032	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		887	886	885	884	883	882	881	880	879	878	877	876	10,578
	b. Equity Component Grossed Up For Taxes	8.02%		2,411	2,408	2,405	2,403	2,400	2,397	2,394	2,392	2,389	2,386	2,383	2,380	28,748
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.30%		413	413	413	413	413	413	413	413	413	413	413	413	4,956
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007670		244	244	244	244	244	244	244	244	244	244	244	244	2,928
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,955	$3,951	$3,947	$3,944	$3,940	$3,936	$3,932	$3,929	$3,925	$3,921	$3,917	$3,913	$47,210
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$3,955	$3,951	$3,947	$3,944	$3,940	$3,936	$3,932	$3,929	$3,925	$3,921	$3,917	$3,913	$47,210

For Project: CAIR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$375,039	$49,024	$43,902	$41,266	$120,276	$84,565	$39,073	$57,604	$245,872	$196,886	$78,555	$135,735	$1,467,798
	b. Clearings to Plant			0	0	0	0	0	0	0	0	1,794,173	196,886	78,555	135,735	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$15,381,150	$15,381,150	$15,381,150	$15,381,150	$15,381,150	$15,381,150	$15,381,150	$15,381,150	$15,381,150	$17,175,323	$17,372,209	$17,450,764	$17,586,499	
3	Less: Accumulated Depreciation		(1,092,577)	(1,111,803)	(1,131,029)	(1,150,255)	(1,169,481)	(1,188,707)	(1,207,933)	(1,227,159)	(1,246,385)	(1,266,733)	(1,288,448)	(1,310,261)	(1,332,244)	
4	CWIP - Non-Interest Bearing		737,551	1,112,590	1,161,614	1,205,516	1,246,782	1,367,058	1,451,624	1,490,696	1,548,301	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$15,026,125	$15,381,937	$15,411,735	$15,436,411	$15,458,451	$15,559,501	$15,624,841	$15,644,688	$15,683,066	$15,908,590	$16,083,761	$16,140,503	$16,254,256	
6	Average Net Investment			15,204,031	15,396,836	15,424,073	15,447,431	15,508,976	15,592,171	15,634,764	15,663,877	15,795,828	15,996,176	16,112,132	16,197,379	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		37,407	37,881	37,948	38,006	38,157	38,362	38,466	38,538	38,863	39,356	39,641	39,851	462,476
	b. Equity Component Grossed Up For Taxes	8.02%		101,657	102,946	103,128	103,284	103,696	104,252	104,537	104,732	105,614	106,953	107,729	108,299	1,256,827
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.50%		19,226	19,226	19,226	19,226	19,226	19,226	19,226	19,226	20,348	21,715	21,813	21,983	239,667
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		10,139	10,139	10,139	10,139	10,139	10,139	10,139	10,139	11,321	11,451	11,503	11,592	126,979
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$168,429	$170,192	$170,441	$170,655	$171,218	$171,979	$172,368	$172,635	$176,146	$179,475	$180,686	$181,725	$2,085,949
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$168,429	$170,192	$170,441	$170,655	$171,218	$171,979	$172,368	$172,635	$176,146	$179,475	$180,686	$181,725	$2,085,949

For Project: CAIR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$17,321	$115,117	($59,852)	($557,487)	$0	$0	$0	$0	$0	$0	$0	$0	($484,900)
	b. Clearings to Plant			17,321	115,117	(59,852)	(557,487)	0	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$12,859,283	$12,876,604	$12,991,722	$12,931,870	$12,374,383	$12,374,383	$12,374,383	$12,374,383	$12,374,383	$12,374,383	$12,374,383	$12,374,383	$12,374,383	
3	Less: Accumulated Depreciation		(543,544)	(570,370)	(597,436)	(624,377)	(650,157)	(675,937)	(701,717)	(727,497)	(753,277)	(779,057)	(804,837)	(830,617)	(856,397)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$12,315,740	$12,306,235	$12,394,286	$12,307,493	$11,724,226	$11,698,446	$11,672,666	$11,646,886	$11,621,106	$11,595,326	$11,569,546	$11,543,766	$11,517,986	
6	Average Net Investment			12,310,987	12,350,260	12,350,889	12,015,859	11,711,336	11,685,556	11,659,776	11,633,996	11,608,216	11,582,436	11,556,656	11,530,876	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		30,289	30,385	30,387	29,563	28,814	28,750	28,687	28,623	28,560	28,496	28,433	28,370	349,357
	b. Equity Component Grossed Up For Taxes	8.02%		82,313	82,576	82,580	80,340	78,304	78,132	77,959	77,787	77,615	77,442	77,270	77,098	949,416
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		26,826	27,066	26,941	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	312,853
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		8,488	8,564	8,524	8,157	8,157	8,157	8,157	8,157	8,157	8,157	8,157	8,157	98,989
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$147,916	$148,591	$148,432	$143,840	$141,055	$140,819	$140,583	$140,347	$140,112	$139,875	$139,640	$139,405	$1,710,615
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$147,916	$148,591	$148,432	$143,840	$141,055	$140,819	$140,583	$140,347	$140,112	$139,875	$139,640	$139,405	$1,710,615

For Project: CAIR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$92,873	$697,152	$193,816	($219,225)	$144,691	$87,989	$37,420	$41,013	($527,543)	$35,529	$13,497	$204,088	$801,301
	b. Clearings to Plant			92,873	697,152	193,816	(219,225)	144,691	87,989	37,420	41,013	(527,543)	35,529	13,497	12,509	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$94,129,661	$94,222,535	$94,919,687	$95,113,503	$94,894,277	$95,038,968	$95,126,957	$95,164,378	$95,205,391	$94,677,848	$94,713,377	$94,726,874	$94,739,383	
3	Less: Accumulated Depreciation		(3,745,413)	(3,941,710)	(4,139,459)	(4,337,612)	(4,535,308)	(4,733,306)	(4,931,487)	(5,129,746)	(5,328,091)	(5,525,337)	(5,722,657)	(5,920,005)	(6,117,379)	
4	*CWIP - Non-Interest Bearing*		0	0	0	0	0	0	0	0	0	0	0	0	191,579	
5	Net Investment (Lines 2 + 3 + 4)		$90,384,248	$90,280,825	$90,780,228	$90,775,891	$90,358,969	$90,305,662	$90,195,470	$90,034,632	$89,877,300	$89,152,511	$88,990,720	$88,806,869	$88,813,583	
6	Average Net Investment			90,332,536	90,530,526	90,778,059	90,567,430	90,332,316	90,250,566	90,115,051	89,955,966	89,514,905	89,071,615	88,898,794	88,810,226	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		222,246	222,733	223,342	222,824	222,246	222,045	221,711	221,320	220,235	219,144	218,719	218,501	2,655,066
	b. Equity Component Grossed Up For Taxes	8.02%		603,980	605,303	606,959	605,550	603,978	603,432	602,526	601,462	598,513	595,549	594,393	593,801	7,215,446
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		196,297	197,749	198,153	197,696	197,998	198,181	198,259	198,345	197,246	197,320	197,348	197,374	2,371,966
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		62,108	62,568	62,696	62,551	62,647	62,705	62,729	62,756	62,408	62,432	62,441	62,449	750,490
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,084,631	$1,088,353	$1,091,150	$1,088,621	$1,086,869	$1,086,363	$1,085,225	$1,083,883	$1,078,402	$1,074,445	$1,072,901	$1,072,125	$12,992,968
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,084,631	$1,088,353	$1,091,150	$1,088,621	$1,086,869	$1,086,363	$1,085,225	$1,083,883	$1,078,402	$1,074,445	$1,072,901	$1,072,125	$12,992,968

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$6,729,489	($792,274)	$225,792	$386,512	$383,200	$468,505	$342,730	$379,160	$589,025	$147,235	$85,976	$152,709	$9,098,059
	b. Clearings to Plant			6,729,489	(792,274)	225,792	386,512	383,200	468,505	342,730	379,160	589,025	147,235	77,292	138,926	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$616,066,880	$622,796,370	$622,004,096	$622,229,887	$622,616,399	$622,999,599	$623,468,104	$623,810,834	$624,189,994	$624,779,019	$624,926,254	$625,003,546	$625,142,472	
3	Less: Accumulated Depreciation		(16,419,709)	(17,717,201)	(19,013,043)	(20,309,355)	(21,606,472)	(22,904,388)	(24,203,280)	(25,502,886)	(26,803,282)	(28,104,905)	(29,406,835)	(30,708,737)	(32,011,109)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	8,685	22,468	
5	Net Investment (Lines 2 + 3 + 4)		$599,647,171	$605,079,169	$602,991,053	$601,920,532	$601,009,927	$600,095,211	$599,264,824	$598,307,948	$597,386,712	$596,674,114	$595,519,419	$594,303,493	$593,153,830	
6	*Average Net Investment*			*602,363,170*	*604,035,111*	*602,455,793*	*601,465,230*	*600,552,569*	*599,680,018*	*598,786,386*	*597,847,330*	*597,030,413*	*596,096,767*	*594,911,456*	*593,728,662*	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,482,002	1,486,115	1,482,229	1,479,792	1,477,547	1,475,400	1,473,202	1,470,891	1,468,881	1,466,584	1,463,668	1,460,758	17,687,069
	b. Equity Component Grossed Up For Taxes	8.02%		4,027,509	4,038,688	4,028,129	4,021,505	4,015,403	4,009,569	4,003,594	3,997,315	3,991,853	3,985,611	3,977,686	3,969,777	48,066,639
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. *Depreciation*	2.50%		*1,297,492*	*1,295,842*	*1,296,312*	*1,297,117*	*1,297,916*	*1,298,892*	*1,299,606*	*1,300,396*	*1,301,623*	*1,301,930*	*1,301,902*	*1,302,372*	*15,591,400*
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		410,527	410,004	410,153	410,408	410,661	410,969	411,195	411,445	411,834	411,931	411,982	412,073	4,933,182
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$7,217,530	$7,230,649	$7,216,823	$7,208,822	$7,201,527	$7,194,830	$7,187,597	$7,180,047	$7,174,191	$7,166,056	$7,155,238	$7,144,980	$86,278,290
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$7,217,530	$7,230,649	$7,216,823	$7,208,822	$7,201,527	$7,194,830	$7,187,597	$7,180,047	$7,174,191	$7,166,056	$7,155,238	$7,144,980	$86,278,290

For Project: CAIR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$388	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$388
	b. Clearings to Plant			388	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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$61,260,314	$61,260,702	$61,260,702	$61,260,702	$61,260,702	$61,260,702	$61,260,702	$61,260,702	$61,260,702	$61,260,702	$61,260,702	$61,260,702	$61,260,702	
3	Less: Accumulated Depreciation		(2,327,461)	(2,455,087)	(2,582,713)	(2,710,339)	(2,837,965)	(2,965,591)	(3,093,217)	(3,220,843)	(3,348,469)	(3,476,095)	(3,603,721)	(3,731,347)	(3,858,973)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$58,932,853	$58,805,615	$58,677,989	$58,550,363	$58,422,737	$58,295,111	$58,167,485	$58,039,859	$57,912,233	$57,784,607	$57,656,981	$57,529,355	$57,401,729	
6	Average Net Investment			58,869,234	58,741,802	58,614,176	58,486,550	58,358,924	58,231,298	58,103,672	57,976,046	57,848,420	57,720,794	57,593,168	57,465,542	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		144,837	144,523	144,209	143,895	143,581	143,267	142,953	142,639	142,325	142,011	141,697	141,383	1,717,320
	b. Equity Component Grossed Up For Taxes	8.02%		393,610	392,758	391,905	391,052	390,198	389,345	388,492	387,638	386,785	385,932	385,078	384,225	4,667,018
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	1,531,512
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	484,572
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$706,454	$705,288	$704,121	$702,954	$701,786	$700,619	$699,452	$698,284	$697,117	$695,950	$694,782	$693,615	$8,400,422
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$706,454	$705,288	$704,121	$702,954	$701,786	$700,619	$699,452	$698,284	$697,117	$695,950	$694,782	$693,615	$8,400,422

For Project: CAIR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			($6,684,218)	$87	$18,857	$13,156	$34,941	$9,454	$5,535	($40,379)	($39,947)	$1,716	$4,153	$3,051	($6,673,593)
	b. Clearings to Plant			(6,684,218)	87	18,857	13,156	34,941	9,454	5,535	(40,379)	(39,947)	1,716	4,153	3,051	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$136,523,748	$129,839,530	$129,839,617	$129,858,474	$129,871,630	$129,906,570	$129,916,025	$129,921,560	$129,881,181	$129,841,234	$129,842,950	$129,847,103	$129,850,154	
3	Less: Accumulated Depreciation		(3,555,508)	(3,826,007)	(4,096,506)	(4,367,044)	(4,637,610)	(4,908,249)	(5,178,907)	(5,449,577)	(5,720,163)	(5,990,666)	(6,261,172)	(6,531,687)	(6,802,208)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$132,968,240	$126,013,523	$125,743,111	$125,491,430	$125,234,020	$124,998,321	$124,737,118	$124,471,983	$124,161,018	$123,850,568	$123,581,778	$123,315,416	$123,047,946	
6	Average Net Investment			129,490,881	125,878,317	125,617,271	125,362,725	125,116,171	124,867,720	124,604,550	124,316,501	124,005,793	123,716,173	123,448,597	123,181,681	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		318,588	309,700	309,058	308,431	307,825	307,214	306,566	305,857	305,093	304,380	303,722	303,065	3,689,499
	b. Equity Component Grossed Up For Taxes	8.02%		865,799	841,645	839,900	838,198	836,549	834,888	833,129	831,203	829,125	827,189	825,400	823,615	10,026,640
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		270,499	270,499	270,538	270,566	270,639	270,658	270,670	270,586	270,503	270,506	270,515	270,521	3,246,700
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		85,586	85,586	85,598	85,607	85,630	85,636	85,640	85,613	85,587	85,588	85,591	85,593	1,027,255
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,540,472	$1,507,430	$1,505,094	$1,502,802	$1,500,643	$1,498,396	$1,496,005	$1,493,259	$1,490,308	$1,487,663	$1,485,228	$1,482,794	$17,990,094
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,540,472	$1,507,430	$1,505,094	$1,502,802	$1,500,643	$1,498,396	$1,496,005	$1,493,259	$1,490,308	$1,487,663	$1,485,228	$1,482,794	$17,990,094

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing Controls (Project 7.4g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$850,198	$850,198	$850,198	$850,198	$850,198	$850,198	$850,198	$850,198	$850,198	$850,198	$850,198	$850,198	$850,198	
3	Less: Accumulated Depreciation		(13,643)	(15,414)	(17,185)	(18,956)	(20,727)	(22,498)	(24,269)	(26,040)	(27,811)	(29,582)	(31,353)	(33,124)	(34,895)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$836,555	$834,784	$833,013	$831,242	$829,471	$827,700	$825,929	$824,158	$822,387	$820,616	$818,845	$817,074	$815,303	
6	Average Net Investment			835,669	833,898	832,127	830,356	828,585	826,814	825,043	823,272	821,501	819,730	817,959	816,188	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,056	2,052	2,047	2,043	2,039	2,034	2,030	2,026	2,021	2,017	2,012	2,008	24,385
	b. Equity Component Grossed Up For Taxes	8.02%		5,587	5,576	5,564	5,552	5,540	5,528	5,516	5,505	5,493	5,481	5,469	5,457	66,268
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	21,252
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		560	560	560	560	560	560	560	560	560	560	560	560	6,720
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$9,974	$9,959	$9,942	$9,926	$9,910	$9,893	$9,877	$9,862	$9,845	$9,829	$9,812	$9,796	$118,625
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$9,974	$9,959	$9,942	$9,926	$9,910	$9,893	$9,877	$9,862	$9,845	$9,829	$9,812	$9,796	$118,625

For Project: CAIR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing Controls (Project 7.4h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	($593)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($593)
	b. Clearings to Plant			0	(593)	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$917,991	$917,991	$917,397	$917,397	$917,397	$917,397	$917,397	$917,397	$917,397	$917,397	$917,397	$917,397	$917,397	
3	Less: Accumulated Depreciation		(10,406)	(12,318)	(14,229)	(16,140)	(18,051)	(19,962)	(21,873)	(23,784)	(25,695)	(27,606)	(29,517)	(31,428)	(33,339)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$907,585	$905,673	$903,169	$901,258	$899,347	$897,436	$895,525	$893,614	$891,703	$889,792	$887,881	$885,970	$884,059	
6	Average Net Investment			906,629	904,421	902,213	900,302	898,391	896,480	894,569	892,658	890,747	888,836	886,925	885,014	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,231	2,225	2,220	2,215	2,210	2,206	2,201	2,196	2,192	2,187	2,182	2,177	26,442
	b. Equity Component Grossed Up For Taxes	8.02%		6,062	6,047	6,032	6,020	6,007	5,994	5,981	5,968	5,956	5,943	5,930	5,917	71,857
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,912	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	22,933
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		605	605	605	605	605	605	605	605	605	605	605	605	7,260
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$10,810	$10,788	$10,768	$10,751	$10,733	$10,716	$10,698	$10,680	$10,664	$10,646	$10,628	$10,610	$128,492
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$10,810	$10,788	$10,768	$10,751	$10,733	$10,716	$10,698	$10,680	$10,664	$10,646	$10,628	$10,610	$128,492

For Project: CAIR Crystal River AFUDC - CR4 SCR (Project 7.4i)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$226,769	($457,019)	($345,043)	$115,194	$170,379	$123,438	$84,530	$57,578	($842,067)	$38,994	$23,228	$16,332	($787,688)
	b. Clearings to Plant			226,769	(457,019)	(345,043)	115,194	170,379	123,438	84,530	57,578	(842,067)	38,994	23,228	16,332	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$109,467,569	$109,694,338	$109,237,319	$108,892,276	$109,007,470	$109,177,849	$109,301,286	$109,385,816	$109,443,394	$108,601,327	$108,640,321	$108,663,548	$108,679,881	
3	Less: Accumulated Depreciation		(1,639,649)	(1,868,179)	(2,095,757)	(2,322,616)	(2,549,715)	(2,777,169)	(3,004,880)	(3,232,767)	(3,460,774)	(3,687,027)	(3,913,361)	(4,139,743)	(4,366,159)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$107,827,920	$107,826,159	$107,141,562	$106,569,660	$106,457,755	$106,400,680	$106,296,406	$106,153,049	$105,982,620	$104,914,300	$104,726,960	$104,523,805	$104,313,722	
6	Average Net Investment			107,827,040	107,483,861	106,855,611	106,513,707	106,429,217	106,348,543	106,224,728	106,067,835	105,448,460	104,820,630	104,625,382	104,418,763	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		265,288	264,444	262,898	262,057	261,849	261,651	261,346	260,960	259,436	257,892	257,411	256,903	3,132,135
	b. Equity Component Grossed Up For Taxes	8.02%		720,951	718,657	714,456	712,170	711,605	711,066	710,238	709,189	705,047	700,850	699,544	698,163	8,511,936
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		228,530	227,578	226,859	227,099	227,454	227,711	227,887	228,007	226,253	226,334	226,382	226,416	2,726,510
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		72,307	72,006	71,778	71,854	71,966	72,048	72,103	72,141	71,586	71,612	71,627	71,638	862,666
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,287,076	$1,282,685	$1,275,991	$1,273,180	$1,272,874	$1,272,476	$1,271,574	$1,270,297	$1,262,322	$1,256,688	$1,254,964	$1,253,120	$15,233,247
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,287,076	$1,282,685	$1,275,991	$1,273,180	$1,272,874	$1,272,476	$1,271,574	$1,270,297	$1,262,322	$1,256,688	$1,254,964	$1,253,120	$15,233,247

For Project: CAIR Crystal River AFUDC - CR4 FGD (Project 7.4j)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$160,503	$9,655	($94,650)	($57,177)	($27,439)	$15,733	$7,551	($4,510)	($513,528)	$10,154	$5,579	$4,193	($483,936)
	b. Clearings to Plant			160,503	9,655	(94,650)	(57,177)	(27,439)	15,733	7,551	(4,510)	(513,528)	10,154	5,579	4,193	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$140,054,642	$140,215,145	$140,224,800	$140,130,150	$140,072,974	$140,045,535	$140,061,268	$140,068,819	$140,064,309	$139,550,780	$139,560,934	$139,566,513	$139,570,706	
3	Less: Accumulated Depreciation		(2,102,806)	(2,394,921)	(2,687,056)	(2,978,994)	(3,270,813)	(3,562,575)	(3,854,369)	(4,146,179)	(4,437,980)	(4,728,711)	(5,019,463)	(5,310,227)	(5,600,999)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$137,951,836	$137,820,224	$137,537,744	$137,151,156	$136,802,161	$136,482,960	$136,206,899	$135,922,640	$135,626,329	$134,822,069	$134,541,471	$134,256,286	$133,969,707	
6	Average Net Investment			137,886,030	137,678,984	137,344,450	136,976,658	136,642,560	136,344,929	136,064,769	135,774,484	135,224,199	134,681,770	134,398,878	134,112,996	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		339,243	338,733	337,910	337,005	336,183	335,451	334,762	334,048	332,694	331,359	330,663	329,960	4,018,011
	b. Equity Component Grossed Up For Taxes	8.02%		921,931	920,547	918,310	915,851	913,617	911,627	909,754	907,813	904,133	900,507	898,615	896,704	10,919,409
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		292,115	292,135	291,938	291,819	291,762	291,794	291,810	291,801	290,731	290,752	290,764	290,772	3,498,193
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		92,425	92,432	92,369	92,331	92,313	92,324	92,329	92,326	91,987	91,994	91,998	92,000	1,106,828
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,645,714	$1,643,847	$1,640,527	$1,637,006	$1,633,875	$1,631,196	$1,628,655	$1,625,988	$1,619,545	$1,614,612	$1,612,040	$1,609,436	$19,542,441
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,645,714	$1,643,847	$1,640,527	$1,637,006	$1,633,875	$1,631,196	$1,628,655	$1,625,988	$1,619,545	$1,614,612	$1,612,040	$1,609,436	$19,542,441

For Project: CAIR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			($205)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($205)
	b. Clearings to Plant			(205)	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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$20,988,402	$20,988,196	$20,988,196	$20,988,196	$20,988,196	$20,988,196	$20,988,196	$20,988,196	$20,988,196	$20,988,196	$20,988,196	$20,988,196	$20,988,196	
3	Less: Accumulated Depreciation		(550,130)	(593,855)	(637,580)	(681,305)	(725,030)	(768,755)	(812,480)	(856,205)	(899,930)	(943,655)	(987,380)	(1,031,105)	(1,074,830)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$20,438,272	$20,394,341	$20,350,616	$20,306,891	$20,263,166	$20,219,441	$20,175,716	$20,131,991	$20,088,266	$20,044,541	$20,000,816	$19,957,091	$19,913,366	
6	Average Net Investment			20,416,307	20,372,479	20,328,754	20,285,029	20,241,304	20,197,579	20,153,854	20,110,129	20,066,404	20,022,679	19,978,954	19,935,229	
7	*Return on Average Net Investment*															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		50,230	50,123	50,015	49,908	49,800	49,692	49,585	49,477	49,370	49,262	49,154	49,047	595,663
	b. Equity Component Grossed Up For Taxes	8.02%		136,507	136,214	135,922	135,629	135,337	135,045	134,752	134,460	134,168	133,875	133,583	133,291	1,618,783
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	524,700
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. *Dismantlement*			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	166,020
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	*Total System Recoverable Expenses (Lines 7 + 8)*			$244,297	$243,897	$243,497	$243,097	$242,697	$242,297	$241,897	$241,497	$241,098	$240,697	$240,297	$239,898	$2,905,166
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$244,297	$243,897	$243,497	$243,097	$242,697	$242,297	$241,897	$241,497	$241,098	$240,697	$240,297	$239,898	$2,905,166

For Project: CAIR Crystal River AFUDC - CR5 Acid Mist Mitigation Controls (Project 7.4l)
(in Dollars)

Line	Description		*Beginning of* Period Amount	*Actual* Jan-11	*Actual* Feb-11	*Actual* Mar-11	*Actual* Apr-11	*Actual* May-11	*Actual* Jun-11	*Actual* Jul-11	*Actual* Aug-11	*Actual* Sep-11	*Actual* Oct-11	*Actual* Nov-11	*Actual* Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
	b. Clearings to Plant			1	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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$9,406,704	$9,406,705	$9,406,705	$9,406,705	$9,406,705	$9,406,705	$9,406,705	$9,406,705	$9,406,705	$9,406,705	$9,406,705	$9,406,705	$9,406,705	
3	Less: Accumulated Depreciation		(146,926)	(166,523)	(186,120)	(205,717)	(225,314)	(244,911)	(264,508)	(284,105)	(303,702)	(323,299)	(342,896)	(362,493)	(382,090)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	*Net Investment (Lines 2 + 3 + 4)*		$9,259,778	$9,240,182	$9,220,585	$9,200,988	$9,181,391	$9,161,794	$9,142,197	$9,122,600	$9,103,003	$9,083,406	$9,063,809	$9,044,212	$9,024,615	
6	Average Net Investment			9,249,980	9,230,384	9,210,787	9,191,190	9,171,593	9,151,996	9,132,399	9,112,802	9,093,205	9,073,608	9,054,011	9,034,414	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		22,758	22,710	22,661	22,613	22,565	22,517	22,469	22,420	22,372	22,324	22,276	22,227	269,912
	b. Equity Component Grossed Up For Taxes	8.02%		61,847	61,716	61,585	61,454	61,323	61,192	61,061	60,930	60,799	60,668	60,537	60,406	733,518
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	235,164
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	74,412
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$110,403	$110,224	$110,044	$109,865	$109,686	$109,507	$109,328	$109,148	$108,969	$108,790	$108,611	$108,431	$1,313,006
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$110,403	$110,224	$110,044	$109,865	$109,686	$109,507	$109,328	$109,148	$108,969	$108,790	$108,611	$108,431	$1,313,006

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - FGD Settling Pond (Project 7.4m)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$52	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$52
	b. Clearings to Plant			52	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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$7,677,264	$7,677,316	$7,677,316	$7,677,316	$7,677,316	$7,677,316	$7,677,316	$7,677,316	$7,677,316	$7,677,316	$7,677,316	$7,677,316	$7,677,316	
3	Less: Accumulated Depreciation		(85,596)	(95,193)	(104,790)	(114,387)	(123,984)	(133,581)	(143,178)	(152,775)	(162,372)	(171,969)	(181,566)	(191,163)	(200,760)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$7,591,668	$7,582,123	$7,572,526	$7,562,929	$7,553,332	$7,543,735	$7,534,138	$7,524,541	$7,514,944	$7,505,347	$7,495,750	$7,486,153	$7,476,556	
6	Average Net Investment			7,586,895	7,577,324	7,567,727	7,558,130	7,548,533	7,538,936	7,529,339	7,519,742	7,510,145	7,500,548	7,490,951	7,481,354	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		18,666	18,643	18,619	18,595	18,572	18,548	18,525	18,501	18,477	18,454	18,430	18,406	222,436
	b. Equity Component Grossed Up For Taxes	8.02%		50,727	50,663	50,599	50,535	50,471	50,407	50,343	50,278	50,214	50,150	50,086	50,022	604,495
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.50%		9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	115,164
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	60,732
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$84,051	$83,964	$83,876	$83,788	$83,701	$83,613	$83,526	$83,437	$83,349	$83,262	$83,174	$83,086	$1,002,827
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$84,051	$83,964	$83,876	$83,788	$83,701	$83,613	$83,526	$83,437	$83,349	$83,262	$83,174	$83,086	$1,002,827

For Project: CAIR Crystal River AFUDC - Coal Pile Runoff Treatment System (Project 7.4n)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
	b. Clearings to Plant			1	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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$15,969,105	$15,969,106	$15,969,106	$15,969,106	$15,969,106	$15,969,106	$15,969,106	$15,969,106	$15,969,106	$15,969,106	$15,969,106	$15,969,106	$15,969,106	
3	Less: Accumulated Depreciation		(209,504)	(229,465)	(249,426)	(269,387)	(289,348)	(309,309)	(329,270)	(349,231)	(369,192)	(389,153)	(409,114)	(429,075)	(449,036)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$15,759,601	$15,739,641	$15,719,680	$15,699,719	$15,679,758	$15,659,797	$15,639,836	$15,619,875	$15,599,914	$15,579,953	$15,559,992	$15,540,031	$15,520,070	
6	Average Net Investment			15,749,621	15,729,661	15,709,700	15,689,739	15,669,778	15,649,817	15,629,856	15,609,895	15,589,934	15,569,973	15,550,012	15,530,051	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		38,749	38,700	38,651	38,602	38,553	38,503	38,454	38,405	38,356	38,307	38,258	38,209	461,747
	b. Equity Component Grossed Up For Taxes	8.02%		105,305	105,171	105,038	104,904	104,771	104,638	104,504	104,371	104,237	104,104	103,970	103,837	1,254,850
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.50%		19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	239,532
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	126,312
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$174,541	$174,358	$174,176	$173,993	$173,811	$173,628	$173,445	$173,263	$173,080	$172,898	$172,715	$172,533	$2,082,441
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$174,541	$174,358	$174,176	$173,993	$173,811	$173,628	$173,445	$173,263	$173,080	$172,898	$172,715	$172,533	$2,082,441

For Project: CAIR Crystal River AFUDC - Dibasic Acid Additive System (Project 7.4o)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
	b. Clearings to Plant			1	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	Plant-in-Service/Depreciation Base		$1,094,417	$1,094,418	$1,094,418	$1,094,418	$1,094,418	$1,094,418	$1,094,418	$1,094,418	$1,094,418	$1,094,418	$1,094,418	$1,094,418	$1,094,418	
3	Less: Accumulated Depreciation		(8,752)	(11,032)	(13,312)	(15,592)	(17,872)	(20,152)	(22,432)	(24,712)	(26,992)	(29,272)	(31,552)	(33,832)	(36,112)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,085,666	$1,083,387	$1,081,107	$1,078,827	$1,076,547	$1,074,267	$1,071,987	$1,069,707	$1,067,427	$1,065,147	$1,062,867	$1,060,587	$1,058,307	
6	Average Net Investment			1,084,526	1,082,247	1,079,967	1,077,687	1,075,407	1,073,127	1,070,847	1,068,567	1,066,287	1,064,007	1,061,727	1,059,447	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,668	2,663	2,657	2,651	2,646	2,640	2,635	2,629	2,623	2,618	2,612	2,607	31,649
	b. Equity Component Grossed Up For Taxes	8.02%		7,251	7,236	7,221	7,206	7,190	7,175	7,160	7,145	7,129	7,114	7,099	7,084	86,010
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	27,360
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		721	721	721	721	721	721	721	721	721	721	721	721	8,652
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$12,920	$12,900	$12,879	$12,858	$12,837	$12,816	$12,796	$12,775	$12,753	$12,733	$12,712	$12,692	$153,671
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$12,920	$12,900	$12,879	$12,858	$12,837	$12,816	$12,796	$12,775	$12,753	$12,733	$12,712	$12,692	$153,671

For Project: CAIR Crystal River AFUDC - Bottom Ash (PH)/Fly Ash (Ammonia) (Project 7.4p)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			($11,534)	$0	$0	$8,879	$12	$905	($0)	$0	$12,206	$2,072	$21,138	$44,001	$77,680
	b. Clearings to Plant			0	0	0	0	5,316	32,418	(0)	0	12,206	2,072	21,138	44,001	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		$0	$0	$0	$0	$0	$5,316	$37,734	$37,734	$37,734	$49,940	$52,013	$73,151	$117,152	
3	Less: Accumulated Depreciation		0	0	0	0	0	(5)	(43)	(109)	(175)	(262)	(353)	(481)	(686)	
4	CWIP - Non-Interest Bearing		39,471	27,938	27,938	27,938	36,817	31,514	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$39,471	$27,938	$27,938	$27,938	$36,817	$36,825	$37,692	$37,626	$37,560	$49,679	$51,660	$72,670	$116,466	
6	Average Net Investment			33,705	27,938	27,938	32,378	36,821	37,259	37,659	37,593	43,619	50,670	62,165	94,568	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		83	69	69	80	91	92	93	92	107	125	153	233	1,287
	b. Equity Component Grossed Up For Taxes	8.02%		225	187	187	216	246	249	252	251	292	339	416	632	3,492
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.10%		0	0	0	0	5	38	66	66	87	91	128	205	686
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		0	0	0	0	4	25	25	25	33	34	48	77	271
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$308	$256	$256	$296	$346	$404	$436	$434	$519	$589	$745	$1,147	$5,736
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$308	$256	$256	$296	$346	$404	$436	$434	$519	$589	$745	$1,147	$5,736

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes	8.02%		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
8	Investment Expenses															
	a. Depreciation	2.50%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009790		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Actual Jul-11	Actual Aug-11	Actual Sep-11	Actual Oct-11	Actual Nov-11	Actual Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$361,735	$361,735	$361,735	$361,735	$361,735	$361,735	$361,735	$361,735	$361,735	$361,735	$361,735	$361,735	$361,735	
3	Less: Accumulated Depreciation		(8,578)	(9,090)	(9,602)	(10,114)	(10,626)	(11,138)	(11,650)	(12,162)	(12,674)	(13,186)	(13,698)	(14,210)	(14,722)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$353,158	$352,646	$352,134	$351,622	$351,110	$350,598	$350,086	$349,574	$349,062	$348,550	$348,038	$347,526	$347,014	
6	Average Net Investment			352,902	352,390	351,878	351,366	350,854	350,342	349,830	349,318	348,806	348,294	347,782	347,270	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		868	867	866	864	863	862	861	859	858	857	856	854	10,335
	b. Equity Component Grossed Up For Taxes	8.02%		2,360	2,356	2,353	2,349	2,346	2,342	2,339	2,336	2,332	2,329	2,325	2,322	28,089
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.70%		512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009790		295	295	295	295	295	295	295	295	295	295	295	295	3,540
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$4,035	$4,030	$4,026	$4,020	$4,016	$4,011	$4,007	$4,002	$3,997	$3,993	$3,988	$3,983	$48,108
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$4,035	$4,030	$4,026	$4,020	$4,016	$4,011	$4,007	$4,002	$3,997	$3,993	$3,988	$3,983	$48,108

Progress Energy Florida, Inc.
Environmental Cost Recovery
Commission Forms 42-1E Through 42-9E

January 2012 - December 2012
Calculation for the Current Period Estimated / Actual Amount
Actuals for the Period of January through June 2012
Estimated for the Period July through December 2012

DOCKET NO. 120007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 28
PARTY Progress Energy Florida
DESCRIPTION Thomas Foster (TGF-1) PSC Forms 42-1E
DATE through 42-9E 1/12-12/12

Docket No. 120007-EI
Progress Energy Florida, Inc.
Witness T.G. Foster
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Form 42-1E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period (Form 42-2E, Line 5)	$ 14,627,204
2	Interest Provision (Form 42-2E, Line 6)	5,770
3	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2013 to December 2013 (Lines 1 + 2 + 3)	**$ 14,632,974**

Docket No. 120007-EI
Progress Energy Florida, Inc.
Witness T.G. Foster
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Form 42-2E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$14,370,516	$13,401,006	$14,006,701	$15,031,317	$15,786,345	$18,161,275	$19,414,591	$20,365,360	$20,036,296	$17,401,399	$15,691,950	$14,820,711	$198,487,468
2	True-Up Provision (Order No. PSC-11-0553-FOF-EI)	$8,785,176	732,098	732,098	732,098	732,098	732,098	732,098	732,098	732,098	732,098	732,098	732,098	732,098	8,785,176
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$15,102,614	14,133,104	14,738,799	15,763,415	16,518,443	18,893,373	20,146,689	21,097,458	20,768,394	18,133,497	16,424,048	15,552,809	207,272,644
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5E, Line 9)		$2,220,085	2,801,025	3,919,052	3,428,261	2,621,058	3,191,727	2,537,698	2,777,570	2,634,150	2,431,487	2,615,256	2,842,370	34,019,739
	b. Capital Investment Projects (Form 42-7E, Line 9)		13,267,518	13,246,213	13,227,030	13,210,083	13,199,421	13,186,379	13,187,628	13,205,848	13,216,976	13,213,874	13,217,227	13,247,504	158,625,701
	c. Other														0
	d. Total Jurisdictional ECRC Costs		$15,487,603	16,047,238	17,146,082	16,638,344	15,820,479	16,378,106	15,725,326	15,983,418	15,851,126	15,645,361	15,832,483	16,089,874	192,645,440
5	Over/(Under) Recovery (Line 3 - Line 4d)		($384,988)	(1,914,135)	(2,407,282)	(874,929)	697,964	2,515,267	4,421,363	5,114,040	4,917,268	2,488,137	591,565	(537,066)	14,627,204
6	Interest Provision (Form 42-3E, Line 10)		392	466	346	(55)	(143)	(55)	175	497	840	1,078	1,143	1,086	5,770
7	Beginning Balance True-Up & Interest Provision		8,785,176	7,668,482	5,022,715	1,883,681	276,599	242,322	2,025,436	5,714,876	10,097,315	14,283,325	16,040,441	15,901,051	8,785,176
	a. Deferred True-Up - January 2011 to December 2011		($1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)	(1,688,551)
8	True-Up Collected/(Refunded) (see Line 2)		(732,098)	(732,098)	(732,098)	(732,098)	(732,098)	(732,098)	(732,098)	(732,098)	(732,098)	(732,098)	(732,098)	(732,098)	(8,785,176)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$5,979,931	3,334,164	195,130	(1,411,952)	(1,446,229)	336,885	4,026,325	8,408,764	12,594,774	14,351,890	14,212,500	12,944,423	12,944,423
10	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Over/(Under) (Lines 9 + 10)		$5,979,931	$3,334,164	$195,130	($1,411,952)	($1,446,229)	$336,885	$4,026,325	$8,408,764	$12,594,774	$14,351,890	$14,212,500	$12,944,423	$12,944,423

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Progress Energy Florida, Inc.
Witness T.G. Foster
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Form 42-3E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Interest Provision
(in Dollars)

Line	Description	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	$7,096,625	$5,979,931	$3,334,164	$195,130	($1,411,952)	($1,446,229)	$336,885	$4,026,325	$8,408,764	$12,594,774	$14,351,890	$14,212,500	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	5,979,539	3,333,698	194,784	(1,411,897)	(1,446,086)	336,940	4,026,150	8,408,267	12,593,934	14,350,812	14,211,357	12,943,337	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	13,076,164	9,313,629	3,528,948	(1,216,767)	(2,858,038)	(1,109,289)	4,363,034	12,434,592	21,002,698	26,945,586	28,563,248	27,155,837	
4	Average True-Up Amount (Line 3 x 1/2)	6,538,082	4,656,815	1,764,474	(608,384)	(1,429,019)	(554,645)	2,181,517	6,217,296	10,501,349	13,472,793	14,281,624	13,577,919	
5	Interest Rate (Last Business Day of Prior Month)	0.03%	0.12%	0.11%	0.09%	0.12%	0.13%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	
6	Interest Rate (Last Business Day of Current Month)	0.12%	0.11%	0.09%	0.12%	0.13%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.15%	0.23%	0.20%	0.21%	0.25%	0.23%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	
8	Average Interest Rate (Line 7 x 1/2)	0.075%	0.115%	0.100%	0.105%	0.125%	0.115%	0.100%	0.100%	0.100%	0.100%	0.100%	0.100%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.006%	0.010%	0.008%	0.009%	0.010%	0.010%	0.008%	0.008%	0.008%	0.008%	0.008%	0.008%	
10	Interest Provision for the Month (Line 4 x Line 9) (Note 1)	$392	$466	$346	($55)	($143)	($55)	$175	$497	$840	$1,078	$1,143	$1,086	**$5,770**

Note (1) : An accounting adjustment to correct an understated interest rate expense in February 2012 was made for $205 in March 2012; the amount shown in Line 10 reflects the fully adjusted amount.

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Progress Energy Florida, Inc.
Witness T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Form 42-4E

Variance Report of O&M Activities
(In Dollars)

Line			(1) Estimated/ Actual	(2) Projection Filing	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities - System					
	1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$4,026,525	$1,991,964	$2,034,561	102%
	1a	Distribution Substation Environmental Investigation, Remediation, and Pollution	1,226,665	2,099,712	(873,047)	-42%
	2	Distribution System Environmental Investigation, Remediation, and Pollution	521,394	331,000	190,394	58%
	3	Pipeline Integrity Management	1,386,804	1,518,000	(131,196)	-9%
	4	Above Ground Tank Secondary Containment	0	0	0	0%
	5	SO2/NOx Emissions Allowances	4,283,834	7,334,975	(3,051,141)	-42%
	6	Phase II Cooling Water Intake	0	0	0	0%
	6.a	Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0%
	7.2	CAIR/CAMR - Peaking - Demand	138,273	90,700	47,573	52%
	7.4	CAIR/CAMR Crystal River - Base	15,034,802	13,399,625	1,635,177	12%
	7.4	CAIR/CAMR Crystal River - Energy	9,143,354	18,447,976	(9,304,622)	-50%
	7.4	CAIR/CAMR Crystal River - A&G	178,904	253,875	(74,971)	-30%
	7.5	Best Available Retrofit Technology (BART) - Energy	27,000	0	27,000	100%
	8	Arsenic Groundwater Standard - Base	0	0	0	0%
	9	Sea Turtle - Coastal Street Lighting - Distrib	2,496	4,992	(2,496)	-50%
	11	Modular Cooling Towers - Base	902,020	0	902,020	100%
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0%
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0%
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0%
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0%
	16	National Pollutant Discharge Elimination System - Energy	228,446	648,000	(419,554)	-65%
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	16,800	300,000	(283,200)	-94%
	17.1	Mercury & Air Toxic Standards (MATS) Anclote - Energy	0	0	0	0%
2	Total O&M Activities - Recoverable Costs		$37,117,319	$46,420,819	($9,303,500)	-20%
3	Recoverable Costs Allocated to Energy		13,699,435	26,730,951	(13,031,517)	-49%
4	Recoverable Costs Allocated to Demand		23,417,884	19,689,868	3,728,016	19%

Notes:

Column (1) - End of Period Totals on Form 42-5E
Column (2) = 2012 Projection Filing Form 42-2P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Docket No. 120007-EI
Progress Energy Florida, Inc.
Witness T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Form 42-5E

O&M Activities
(In Dollars)

Line	Description	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Description of O&M Activities													
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$448,238	$393,677	$378,008	$589,159	$432,936	$324,510	$243,333	$243,333	$243,333	$243,333	$243,333	$243,333	$4,026,525
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	88,536	81,169	71,152	17,804	(8,414)	55,741	$153,446	$153,446	$153,446	$153,446	$153,446	$153,446	1,226,665
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	133,710	25,738	59,067	55,706	(16,412)	60,185	0	1,000	12,000	190,400	0	0	521,394
3	Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	21,277	30,555	62,082	34,766	(112,192)	29,317	34,000	152,000	137,000	34,000	482,000	482,000	1,366,804
4	Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
5	SO2/NOx Emissions Allowances	284,120	243,360	392,893	377,749	487,020	466,374	462,196	469,679	344,372	286,042	258,059	211,970	4,283,834
6	Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
6a	Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	0	7,928	(14,477)	58,230	38,350	10,876	0	0	0	37,365	0	0	138,273
7.4	CAIR/CAMR Crystal River - Base	1,092,077	1,747,307	1,357,582	1,360,115	1,066,320	1,161,161	1,001,217	1,210,292	1,245,207	971,768	1,418,516	1,403,239	15,034,802
7.4	CAIR/CAMR Crystal River - Energy	373,044	509,484	1,427,447	1,226,872	892,445	822,278	752,790	726,068	692,766	650,058	385,535	684,567	9,143,354
7.4	CAIR/CAMR Crystal River - A&G	6,980	14,822	22,511	9,460	18,302	17,376	14,909	14,909	14,909	14,909	14,909	14,909	178,904
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	11,870	5,254	9,876	0	0	0	0	27,000
8	Arsenic Groundwater Standard - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	0	416	416	416	416	416	416	2,496
11	Modular Cooling Towers - Base	0	0	451,261	0	0	442,191	8,568	0	0	0	0	0	902,020
12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
16	National Pollutant Discharge Elimination System - Energy	8,597	9,101	3,889	6,858	7,718	40,248	36,897	30,810	22,122	23,882	24,723	13,600	228,446
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	0	16,800	0	0	0	0	0	0	0	0	0	0	16,800
17.1	Mercury & Air Toxic Standards (MATS) Anclote - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total of O&M Activities	2,456,579	3,079,942	4,211,416	3,736,719	2,806,074	3,442,127	2,713,025	3,011,829	2,865,570	2,605,619	2,980,937	3,207,480	37,117,319
3	Recoverable Costs Allocated to Energy	665,761	778,746	1,824,230	1,611,479	1,387,183	1,340,770	1,257,137	1,236,433	1,059,260	959,982	668,318	910,137	13,699,435
4	Recoverable Costs Allocated to Demand - Transm	448,238	393,677	378,008	589,159	432,936	324,510	243,333	243,333	243,333	243,333	243,333	243,333	4,026,525
	Recoverable Costs Allocated to Demand - Distrib	222,246	106,907	130,219	73,510	(24,825)	115,926	153,862	154,862	165,862	344,262	153,862	153,862	1,750,555
	Recoverable Costs Allocated to Demand - Prod-Base	1,092,077	1,747,307	1,808,843	1,360,115	1,066,320	1,603,352	1,009,785	1,210,292	1,245,207	971,768	1,418,516	1,403,239	15,936,822
	Recoverable Costs Allocated to Demand - Prod-Intm	21,277	30,555	62,082	34,766	(112,192)	29,317	34,000	152,000	137,000	34,000	482,000	482,000	1,386,804
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	7,928	(14,477)	58,230	38,350	10,876	0	0	0	37,365	0	0	138,273
	Recoverable Costs Allocated to Demand - A&G	6,980	14,822	22,511	9,460	18,302	17,376	14,909	14,909	14,909	14,909	14,909	14,909	178,904
5	Retail Energy Jurisdictional Factor	0.99120	0.99240	0.99560	0.99550	0.99520	0.99280	0.99480	0.99440	0.99390	0.99370	0.99410	0.99490	
6	Retail Transmission Demand Jurisdictional Factor	0.70795	0.70795	0.70795	0.70795	0.70795	0.70795	0.70795	0.70795	0.70795	0.70795	0.70795	0.70795	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
	Retail Production Demand Jurisdictional Factor - Base	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
	Retail Production Demand Jurisdictional Factor - Intm	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	
	Retail Production Demand Jurisdictional Factor - Peaking	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	
	Retail Production Demand Jurisdictional Factor - A&G	0.92640	0.92640	0.92640	0.92640	0.92640	0.92640	0.92640	0.92640	0.92640	0.92640	0.92640	0.92640	
7	Jurisdictional Energy Recoverable Costs (A)	659,902	772,827	1,816,203	1,604,227	1,380,525	1,331,116	1,250,599	1,229,509	1,052,799	953,934	664,374	905,495	13,621,510
8	Jurisdictional Demand Recoverable Costs - Transm (B)	317,330	278,704	267,611	417,095	306,497	229,737	172,268	172,268	172,268	172,268	172,268	172,268	2,850,582
	Jurisdictional Demand Recoverable Costs - Distrib (B)	221,410	106,505	129,730	73,234	(24,732)	115,490	153,283	154,280	165,238	342,968	153,283	153,283	1,743,972
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	1,001,249	1,601,984	1,658,402	1,246,994	977,635	1,470,002	925,801	1,109,633	1,141,643	890,947	1,300,539	1,286,532	14,611,361
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	13,727	19,714	40,054	22,431	(72,385)	18,915	21,936	98,069	88,391	21,936	310,981	310,981	894,750
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	7,559	(13,802)	55,516	36,563	10,370	0	0	0	35,623	0	0	131,829
	Jurisdictional Demand Recoverable Costs - A&G (B)	6,467	13,732	20,854	8,764	16,955	16,097	13,811	13,811	13,811	13,811	13,811	13,811	165,735
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$2,220,085	$2,801,025	$3,919,052	$3,428,261	$2,621,058	$3,191,727	$2,537,698	$2,777,570	$2,634,150	$2,431,487	$2,615,256	$2,842,370	$34,019,739

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

Docket No. 120007-EI
Progress Energy Florida, Inc.
Witness T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Variance Report of Capital Investment Activities - Recoverable Costs
(In Dollars)

Line		(1) Estimated/ Actual	(2) Projection Filing	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities				
	3.x Pipeline Integrity Management - Bartow/Anclote Pipeline	$454,882	$451,442	$3,440	1%
	4.x Above Ground Tank Secondary Containment	2,029,364	2,084,603	(55,239)	-3%
	5 SO2 / NOx Emissions Allowances	2,576,839	2,449,462	127,377	5%
	7.x CAIR/CAMR	167,639,338	170,991,289	(3,351,952)	-2%
	9 Sea Turtle - Coastal Street Lighting	1,413	1,695	(282)	-17%
	10.x Underground Storage Tanks	31,000	30,940	60	0%
	11 Modular Cooling Towers	5,244	5,256	(12)	0%
	11.1 Thermal Discharge Permanent Cooling Tower	47,255	47,435	(180)	0%
	16 National Pollutant Discharge Elimination System (NPDES) - Intermediate	54,025	191,525	(137,500)	-72%
	17.x Mercury and Air Toxics Standards (MATS)	38,011	0	38,011	100%
2	Total Capital Investment Activities - Recoverable Costs	$172,877,371	$176,253,647	($3,376,277)	-2%
3	Recoverable Costs Allocated to Energy	2,710,280	2,514,359	$195,921	8%
4	Recoverable Costs Allocated to Demand	170,167,091	173,739,288	(3,572,197)	-2%

Notes:

Column (1) is the End of Period Totals on Form 42-7E
Column (2) = Per 2012 Projection Filing Form 42-3P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Form 42-7E

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$38,316	$38,241	$38,167	$38,093	$38,018	$37,944	37,870	$37,795	$37,721	$37,647	$37,572	$37,498	$454,882
4.1	Above Ground Tank Secondary Containment - Peaking	135,592	135,340	135,107	134,806	134,569	134,205	133,902	133,598	133,294	132,991	132,687	132,384	1,608,475
4.2	Above Ground Tank Secondary Containment - Base	32,340	32,264	32,229	32,173	32,118	32,063	32,007	31,952	31,897	31,842	31,786	31,731	384,422
4.3	Above Ground Tank Secondary Containment - Intermediate	3,065	3,061	3,056	3,052	3,046	3,041	3,037	3,031	3,027	3,022	3,017	3,012	36,467
5	SO2/NOX Emissions Allowances - Energy	233,651	231,238	228,328	224,804	220,849	216,489	212,243	207,981	204,258	201,375	198,886	196,737	2,576,839
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR CT's - Peaking	21,219	21,187	21,155	21,122	21,090	21,057	21,025	20,993	20,960	20,928	20,895	20,863	252,494
7.3	CAMR Crystal River - Base	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
7.4	CAIR/CAMR Crystal River AFUDC - Base	13,975,743	13,954,944	13,937,239	13,921,806	13,913,874	13,906,254	13,910,205	13,931,940	13,946,631	13,944,381	13,946,036	13,970,635	167,259,686
7.4	CAIR/CAMR Crystal River AFUDC - Energy	7,649	7,647	7,122	7,986	8,895	8,151	7,809	7,994	7,994	7,994	7,994	7,994	95,430
9	Sea Turtle - Coastal Street Lighting -Distribution	115	115	115	115	115	113	115	117	120	122	124	127	1,413
10.1	Underground Storage Tanks - Base	1,757	1,755	1,752	1,749	1,746	1,744	1,741	1,738	1,735	1,733	1,730	1,727	20,907
10.2	Underground Storage Tanks - Intermediate	851	850	847	846	844	842	840	839	836	835	832	831	10,093
11	Modular Cooling Towers - Base	437	437	437	437	437	437	437	437	437	437	437	437	5,244
11.1	Crystal River Thermal Discharge Compliance Project - Base	3,963	3,959	3,955	3,949	3,945	3,940	3,936	3,931	3,926	3,922	3,917	3,912	47,255
16	National Pollutant Discharge Elimination System (NPDES) - Intermediate	576	659	1,070	1,540	1,661	1,737	2,271	3,186	4,101	5,015	9,586	22,621	54,025
17	MATS - Crystal River 4 & 5 - Energy	0	0	0	0	0	4	1,837	4,124	5,439	7,154	8,869	10,584	38,011
17.1	MATS - Anclote Conversion - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$14,457,918	$14,434,561	$14,413,223	$14,395,122	$14,383,851	$14,370,665	$14,371,919	$14,392,300	$14,405,020	$14,402,042	$14,407,014	$14,443,737	$172,877,371
3	Recoverable Costs Allocated to Energy	241,300	239,085	235,450	232,790	229,744	224,644	221,889	220,099	217,691	216,523	215,749	215,315	2,710,280
	Recoverable Costs Allocated to Distribution Demand	115	115	115	115	115	113	115	117	120	122	124	127	1,413
4	Recoverable Costs Allocated to Demand - Production - Base	14,016,884	13,996,023	13,978,256	13,962,758	13,954,764	13,947,082	13,950,970	13,972,642	13,987,270	13,984,959	13,986,550	14,011,086	167,749,242
	Recoverable Costs Allocated to Demand - Production - Intermediate	42,808	42,811	43,140	43,531	43,569	43,564	44,018	44,851	45,685	46,519	51,009	63,962	555,467
	Recoverable Costs Allocated to Demand - Production - Peaking	156,811	156,527	156,262	155,928	155,659	155,262	154,927	154,591	154,254	153,919	153,582	153,247	1,860,969
5	Retail Energy Jurisdictional Factor	0.99120	0.99240	0.99560	0.99550	0.99520	0.99280	0.99480	0.99440	0.99390	0.99370	0.99410	0.99490	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
6	Retail Demand Jurisdictional Factor - Production - Base	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	
7	Jurisdictional Energy Recoverable Costs (B)	239,177	237,268	234,414	231,742	228,641	223,026	220,735	218,867	216,363	215,159	214,476	214,217	2,694,086
	Jurisdictional Demand Recoverable Costs - Distribution (B)	115	115	115	115	115	113	115	117	120	122	124	127	1,408
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	12,851,104	12,831,978	12,815,689	12,801,480	12,794,151	12,787,108	12,790,673	12,810,542	12,823,953	12,821,834	12,823,293	12,845,788	153,797,594
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	27,619	27,621	27,833	28,086	28,110	28,107	28,400	28,937	29,475	30,014	32,910	41,268	358,381
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	149,502	149,232	148,979	148,661	148,404	148,026	147,706	147,386	147,065	146,745	146,424	146,104	1,774,233
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$13,267,518	$13,246,213	$13,227,030	$13,210,083	$13,199,421	$13,186,379	$13,187,628	$13,205,848	$13,216,976	$13,213,874	$13,217,227	$13,247,504	$158,625,701

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9; Form 42-8E, Line 5 for Projects 5 - Allowances and Project 7. 4 - Reagents
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Docket No. 120007-EI
Progress Energy Florida, Inc.
Witness T.G. Foster
Exhibit No. _____ (TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6
	b. Clearings to Plant			6	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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		3,719,062	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	
3	Less: Accumulated Depreciation		(751,335)	(759,463)	(767,591)	(775,719)	(783,847)	(791,975)	(800,103)	(808,231)	(816,359)	(824,487)	(832,615)	(840,743)	(848,871)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,967,727	$2,959,605	$2,951,477	$2,943,349	$2,935,221	$2,927,093	$2,918,965	$2,910,837	$2,902,709	$2,894,581	$2,886,453	$2,878,325	$2,870,197	
6	Average Net Investment			$2,963,666	$2,955,541	$2,947,413	$2,939,285	$2,931,157	$2,923,029	$2,914,901	$2,906,773	$2,898,645	$2,890,517	$2,882,389	$2,874,261	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		7,292	7,272	7,252	7,232	7,212	7,192	7,172	7,152	7,132	7,112	7,092	7,072	86,184
	b. Equity Component Grossed Up For Taxes	8.02%		19,816	19,761	19,707	19,653	19,598	19,544	19,490	19,435	19,381	19,327	19,272	19,218	234,202
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	97,536
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes (D)			3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	36,960
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$38,316	$38,241	$38,167	$38,093	$38,018	$37,944	$37,870	$37,795	$37,721	$37,847	$37,572	$37,498	454,882
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$38,316	$38,241	$38,167	$38,093	$38,018	$37,944	$37,870	$37,795	$37,721	$37,647	$37,572	$37,498	454,882
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			24,721	24,673	24,625	24,577	24,529	24,481	24,433	24,385	24,337	24,289	24,241	24,193	293,484
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$24,721	$24,673	$24,625	$24,577	$24,529	$24,481	$24,433	$24,385	$24,337	$24,289	$24,241	$24,193	$293,484

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - PEAKING (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ (6,417)	$ 10,309	$ 3,083	$ (1,706)	$ (1)	$0	$0	$0	$0	$0	$0	$0	$ 5,267
	b. Clearings to Plant			(6,417)	10,309	3,083	(1,706)	(1)	0	0	0	0	0	0	0	5,267
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		11,296,536	11,290,119	11,300,428	11,303,511	11,301,805	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	
3	Less: Accumulated Depreciation		(1,211,068)	(1,244,233)	(1,277,421)	(1,310,615)	(1,343,806)	(1,376,997)	(1,410,188)	(1,443,379)	(1,476,570)	(1,509,761)	(1,542,952)	(1,576,143)	(1,609,334)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$10,085,468	$10,045,886	$10,023,006	$9,992,895	$9,957,998	$9,924,806	$9,891,615	$9,858,424	$9,825,233	$9,792,042	$9,758,851	$9,725,660	$9,692,469	
6	Average Net Investment			$10,065,677	$10,034,446	$10,007,951	$9,975,447	$9,941,402	$9,908,210	$9,875,019	$9,841,828	$9,808,637	$9,775,446	$9,742,255	9,709,064	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		24,765	24,688	24,623	24,543	24,459	24,377	24,296	24,214	24,132	24,051	23,969	23,887	292,004
	b. Equity Component Grossed Up For Taxes	8.02%		67,301	67,092	66,915	66,698	66,470	66,248	66,026	65,804	65,582	65,360	65,138	64,917	793,551
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			33,165	33,188	33,194	33,191	33,191	33,191	33,191	33,191	33,191	33,191	33,191	33,191	398,266
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes (D)			10,361	10,372	10,375	10,374	10,449	10,389	10,389	10,389	10,389	10,389	10,389	10,389	124,654
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$135,592	$135,340	$135,107	$134,806	$134,569	$134,205	$133,902	$133,598	$133,294	$132,991	$132,687	$132,384	1,608,475
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$135,592	$135,340	$135,107	$134,806	$134,569	$134,205	$133,902	$133,598	$133,294	$132,991	$132,687	$132,384	1,608,475
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			129,272	129,032	128,810	128,523	128,297	127,950	127,661	127,371	127,081	126,793	126,503	126,214	1,533,507
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$129,272	$129,032	$128,810	$128,523	$128,297	$127,950	$127,661	$127,371	$127,081	$126,793	$126,503	$126,214	$1,533,507

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	
3	Less: Accumulated Depreciation		(215,858)	(221,904)	(227,950)	(233,996)	(240,042)	(246,088)	(252,134)	(258,180)	(264,226)	(270,272)	(276,318)	(282,364)	(288,410)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$2,670,413	$2,664,367	$2,658,321	$2,652,275	$2,646,229	$2,640,183	$2,634,137	$2,628,091	$2,622,045	$2,615,999	$2,609,953	$2,603,907	$2,597,861	
6	Average Net Investment			$2,667,390	$2,661,344	$2,655,298	$2,649,252	$2,643,206	$2,637,160	$2,631,114	$2,625,068	$2,619,022	$2,612,976	$2,606,930	$2,600,884	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		6,563	6,548	6,533	6,518	6,503	6,488	6,473	6,458	6,444	6,429	6,414	6,399	77,770
	b. Equity Component Grossed Up For Taxes (B)	8.02%		17,835	17,794	17,754	17,713	17,673	17,633	17,592	17,552	17,511	17,471	17,430	17,390	211,348
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	72,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	22,752
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$32,340	$32,284	$32,229	$32,173	$32,118	$32,063	$32,007	$31,952	$31,897	$31,842	$31,786	$31,731	384,422
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$32,340	$32,284	$32,229	$32,173	$32,118	$32,063	$32,007	$31,952	$31,897	$31,842	$31,786	$31,731	384,422
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			29,650	29,599	29,549	29,497	29,447	29,396	29,345	29,295	29,244	29,194	29,142	29,092	352,450
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$29,650	$29,599	$29,549	$29,497	$29,447	$29,396	$29,345	$29,295	$29,244	$29,194	$29,142	$29,092	$352,450

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(34,986)	(35,518)	(36,050)	(36,582)	(37,114)	(37,646)	(38,178)	(38,710)	(39,242)	(39,774)	(40,306)	(40,838)	(41,370)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$255,312	$254,780	$254,248	$253,716	$253,184	$252,652	$252,120	$251,588	$251,056	$250,524	$249,992	$249,460	$248,926	
6	Average Net Investment			$255,046	$254,514	$253,982	$253,450	$252,918	$252,386	$251,854	$251,322	$250,790	$250,258	$249,726	$249,194	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		627	626	625	624	622	621	620	618	617	616	614	613	7,443
	b. Equity Component Grossed Up For Taxes	8.02%		1,705	1,702	1,698	1,695	1,691	1,687	1,684	1,680	1,677	1,673	1,670	1,666	20,228
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			201	201	201	201	201	201	201	201	201	201	201	201	2,412
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,065	$3,061	$3,056	$3,052	$3,046	$3,041	$3,037	$3,031	$3,027	$3,022	$3,017	$3,012	36,467
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$3,065	$3,061	$3,056	$3,052	$3,046	$3,041	$3,037	$3,031	$3,027	$3,022	$3,017	$3,012	36,467
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			1,978	1,975	1,972	1,969	1,965	1,962	1,959	1,956	1,953	1,950	1,947	1,943	23,528
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,978	$1,975	$1,972	$1,969	$1,965	$1,962	$1,959	$1,956	$1,953	$1,950	$1,947	$1,943	$23,528

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Schedule of Amortization and Return
DEFERRED GAIN ON SALES OF EMISSION ALLLOWANCES (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		4,978,189	$4,951,926	$4,928,694	$4,839,184	$4,834,398	$4,777,765	$4,725,137	$4,671,645	$4,617,997	$4,578,519	$4,542,704	$4,508,812	$4,487,131	$4,487,131
	b. 25401FL Auctioned SO_2 Allowance		(1,558,546)	(1,513,877)	(1,471,208)	(1,428,539)	(1,386,864)	(1,342,720)	(1,299,955)	(1,257,190)	(1,214,425)	(1,171,661)	(1,128,896)	(1,086,131)	(1,043,366)	($1,043,366)
	c. 1581002 NOx Emission Allowance Inventory		22,265,776	21,965,250	21,702,453	21,356,400	20,941,762	20,467,232	20,010,721	19,559,253	19,100,456	18,752,797	18,459,805	18,192,872	17,959,819	17,959,819
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital		25,687,420	$25,403,298	$25,159,938	$24,767,045	$24,389,296	$23,902,276	$23,435,903	$22,973,707	$22,504,028	$22,159,655	$21,873,613	$21,615,554	$21,403,584	$21,403,584
3	Average Net Investment			$25,545,359	$25,281,618	$24,963,492	$24,578,171	$24,145,786	$23,669,089	$23,204,805	$22,738,868	$22,331,842	$22,016,634	$21,744,584	$21,509,569	
4	Return on Average Net Working Capital Balance (A)															
	a. Debt Component (Line 3 x 2.95% x 1/12)	2.95%		62,850	62,201	61,418	60,470	59,406	58,233	57,091	55,945	54,943	54,168	53,498	52,920	693,143
	b. Equity Component Grossed Up For Taxes	8.02%		170,801	169,037	166,910	164,334	161,443	158,256	155,152	152,036	149,315	147,207	145,388	143,817	1,883,696
5	Total Return Component (B)			$233,651	$231,238	$228,328	$224,804	$220,849	$216,489	$212,243	$207,981	$204,258	$201,375	$198,886	$196,737	2,576,839
6	Expense Dr (Cr)															
	a. 5090001 SO_2 Allowance Expense			26,263	23,232	89,509	4,786	56,634	52,628	53,492	53,648	39,478	35,815	33,892	21,681	491,057
	b. 4074004 Amortization Expense			(42,669)	(42,669)	(42,669)	(41,675)	(44,144)	(42,765)	(42,765)	(42,765)	(42,765)	(42,765)	(42,765)	(42,765)	(513,180)
	c. 5090003 NOx Allowance Expense			300,527	262,797	346,053	414,637	474,531	456,511	451,468	458,796	347,659	292,993	266,932	233,054	4,305,958
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			284,120	243,360	392,893	377,749	487,020	466,374	462,196	469,679	344,372	286,042	258,059	211,970	4,283,834
8	Total System Recoverable Expenses (Lines 5 + 7)			$517,771	$474,598	$621,221	$602,553	$707,869	$682,863	$674,439	$677,660	$548,630	$487,417	$456,945	$408,707	6,860,673
	a. Recoverable costs allocated to Energy			517,771	474,598	621,221	602,553	707,869	682,863	674,439	677,660	548,630	487,417	456,945	408,707	6,860,673
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.99120	0.99240	0.99560	0.99550	0.99520	0.99280	0.99480	0.99440	0.99390	0.99370	0.99410	0.99490	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			$513,215	$470,991	$618,488	$599,841	$704,472	$677,946	$670,932	$673,865	$545,284	$484,346	$454,249	$406,622	6,820,251
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 513,215	$ 470,991	$ 618,488	$ 599,841	$ 704,472	$ 677,946	$ 670,932	$ 673,865	$ 545,284	$ 484,346	$ 454,249	$ 406,622	$ 6,820,251

Notes:
(A) Line 3 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc Tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Intermediate (Project 7.1 - Anclote Low Nox Burners and SOFA)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes	8.02%		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
8	Investment Expenses															
	a. Depreciation (C)	1.60%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.008310		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intm)			0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	
3	Less: Accumulated Depreciation		(176,016)	(179,560)	(183,104)	(186,648)	(190,192)	(193,736)	(197,280)	(200,824)	(204,368)	(207,912)	(211,456)	(215,000)	(218,544)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,760,092	$1,756,548	$1,753,004	$1,749,460	$1,745,916	$1,742,372	$1,738,828	$1,735,284	$1,731,740	$1,728,196	$1,724,652	$1,721,108	$1,717,564	
6	Average Net Investment			$1,758,320	$1,754,776	$1,751,232	$1,747,688	$1,744,144	$1,740,600	$1,737,056	$1,733,512	$1,729,968	$1,726,424	$1,722,880	$1,719,336	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,326	4,317	4,309	4,300	4,291	4,282	4,274	4,265	4,256	4,248	4,239	4,230	51,337
	b. Equity Component Grossed Up For Taxes	8.02%		11,756	11,733	11,709	11,685	11,662	11,638	11,614	11,591	11,567	11,543	11,519	11,496	139,513
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	42,528
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	19,116
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$21,219	$21,187	$21,155	$21,122	$21,090	$21,057	$21,025	$20,993	$20,960	$20,928	$20,895	$20,863	252,494
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$21,219	$21,187	$21,155	$21,122	$21,090	$21,057	$21,025	$20,993	$20,960	$20,928	$20,895	$20,863	252,494
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	0.95339	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			20,230	20,200	20,169	20,138	20,107	20,076	20,045	20,015	19,983	19,953	19,921	19,891	240,726
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$20,230	$20,200	$20,169	$20,138	$20,107	$20,076	$20,045	$20,015	$19,983	$19,953	$19,921	$19,891	$240,726

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
5	Net Investment (Lines 2 + 3 + 4)	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	
6	Average Net Investment		$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	
7	Return on Average Net Investment (B)														
	a. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		711	711	711	711	711	711	711	711	711	711	711	711	$8,532
	b. Equity Component Grossed Up For Taxes 8.02%		1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	23,196
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 2.10%		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. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.007880		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	31,728
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	$2,644	31,728
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)		0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)		2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	29,089
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,424	$2,424	$2,424	$2,424	$2,424	$2,424	$2,424	$2,424	$2,424	$2,424	$2,424	$2,424	$29,089

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$98,466	$30,020	$746,104	$562,420	$1,606,173	$2,351,836	$3,203,196	$5,897,822	$1,790,400	$2,404,391	$2,644,444	$1,008,706	$22,541,982
	b. Clearings to Plant			69,995	29,673	88,769	14,215	1,157,870	4,226	(4,000)	975,805	100,000	0	0	19,019,725	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,248,224,867	1,248,294,663	1,248,324,335	1,248,393,104	1,246,407,319	1,247,565,189	1,247,569,415	1,247,565,415	1,248,541,220	1,248,641,220	1,248,641,220	1,248,641,220	1,267,660,945	
3	Less: Accumulated Depreciation		(63,157,213)	(65,501,963)	(67,846,764)	(70,191,710)	(72,536,679)	(74,883,571)	(77,225,259)	(79,586,914)	(81,909,463)	(84,252,908)	(86,596,352)	(88,939,797)	(91,300,184)	
4	CWIP - AFUDC-Interest Bearing		214,048	240,519	240,866	916,201	1,466,406	2,116,708	4,464,321	7,671,517	12,593,534	14,283,934	16,686,325	19,332,769	1,319,750	
5	Net Investment (Lines 2 + 3 + 4)		$1,183,281,501	$1,181,033,216	$1,178,718,436	$1,177,119,595	$1,175,337,046	$1,174,798,326	$1,174,808,477	$1,175,670,019	$1,179,225,291	$1,178,672,247	$1,178,733,193	$1,179,034,193	$1,177,680,531	
6	Average Net Investment			$1,182,157,359	$1,179,875,828	$1,177,919,016	$1,176,228,321	$1,175,067,888	$1,174,803,402	$1,175,239,248	$1,177,447,655	$1,178,948,769	$1,178,702,720	$1,178,883,693	$1,178,357,362	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,908,476	2,902,863	2,898,049	2,893,869	2,891,034	2,890,383	2,891,456	2,896,889	2,900,582	2,899,977	2,900,422	2,899,127	34,773,147
	b. Equity Component Grossed Up For Taxes	6.02%		7,904,116	7,888,863	7,875,780	7,864,475	7,856,715	7,854,948	7,857,862	7,872,628	7,882,685	7,881,020	7,882,230	7,878,711	94,500,015
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			2,344,751	2,344,800	2,344,947	2,344,969	2,346,893	2,341,688	2,341,655	2,342,550	2,343,445	2,343,445	2,343,445	2,360,368	28,142,952
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			818,398	818,418	818,463	818,473	819,232	819,235	819,232	819,873	819,939	819,939	819,939	832,429	9,843,570
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$13,975,743	$13,954,944	$13,937,239	$13,921,806	$13,913,874	$13,906,254	$13,910,205	$13,931,940	$13,946,631	$13,944,361	$13,946,036	$13,970,635	$167,259,686
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$13,975,743	$13,954,944	$13,937,239	$13,921,806	$13,913,874	$13,906,254	$13,910,205	$13,931,940	$13,946,631	$13,944,361	$13,946,036	$13,970,635	$167,259,686
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91683	0.91683	0.91683	0.91883	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			12,813,385	12,794,316	12,778,084	12,763,934	12,756,662	12,749,676	12,753,298	12,773,225	12,786,694	12,784,631	12,786,148	12,808,702	153,348,754
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$12,813,385	$12,794,316	$12,778,084	$12,763,934	$12,756,662	$12,749,676	$12,753,298	$12,773,225	$12,786,694	$12,784,631	$12,786,148	$12,808,702	$153,348,754

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2012 through December 2012

Schedule of Amortization and Return
For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-products)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Working Capital Dr (Cr)														
	a. 1544001 Ammonia Inventory	$ 21,613	$ 36,991	$ 39,953	$ 55,091	$ 50,699	$ 24,461	$ 41,144	$ 41,390	$ 41,390	$ 41,390	$ 41,390	$ 41,390	$ 41,390	$ 41,390
	b. 1544004 Limestone Inventory	742,609	871,443	767,379	694,804	945,556	924,342	792,332	832,642	832,642	832,642	832,642	832,642	832,642	832,642
2	Total Working Capital	$ 764,222	$ 908,434	$ 807,332	$ 749,895	$ 996,254	$ 948,803	$ 833,476	$ 874,032	$ 874,032	$ 874,032	$ 874,032	$ 874,032	$ 874,032	$ 874,032
3	Average Net Investment		836,328	857,883	778,613	873,074	972,529	891,140	853,754	874,032	874,032	874,032	874,032	874,032	
4	Return on Average Net Working Capital Balance (A)														
	a. Debt Component (Line 3 x 2.95% x 1/12) 2.95%		2,058	2,111	1,916	2,148	2,393	2,192	2,101	2,150	2,150	2,150	2,150	2,150	$25,670
	b. Equity Component Grossed Up For Taxes 8.02%		5,592	5,736	5,206	5,838	6,503	5,958	5,708	5,844	5,844	5,844	5,844	5,844	69,760
5	Total Return Component (B)		7,649	7,847	7,122	7,986	8,895	8,151	7,809	7,994	7,994	7,994	7,994	7,994	95,430
6	Expense Dr (Cr)														
	a. 5020011 Ammonia Expense		178,354	179,808	276,179	270,740	269,594	257,205	229,246	221,684	197,367	184,784	110,186	197,347	2,572,493
	b. 5020012 Limestone Expense		238,713	428,179	570,270	497,453	522,742	525,836	372,413	358,914	353,028	332,128	196,154	348,207	4,744,037
	c. 5020013 Dibasic Acid Expense		0	4,878	0	0	0	0	0	0	0	0	0	0	4,878
	d. 5020003 Gypsum Disposal/Sale		(91,656)	(230,431)	424,468	318,394	(49,984)	(112,969)	69,824	67,269	66,070	62,053	36,723	64,980	624,741
	e. 5020014 Bottom/Fly Ash Reagents Expense		47,633	127,050	156,530	140,285	150,092	152,205	81,307	78,202	76,300	71,094	42,473	74,033	1,197,204
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)		373,044	509,484	1,427,447	1,226,872	892,445	822,278	752,790	726,068	692,766	650,058	385,535	684,567	9,143,353
8	Total System Recoverable Expenses (Lines 5 + 7)		$380,693	$517,331	$1,434,568	$1,234,858	$901,340	$830,428	$760,599	$734,062	$700,760	$658,052	$393,530	$692,561	$9,238,783
	a. Recoverable costs allocated to Energy		380,693	517,331	1,434,568	1,234,858	901,340	830,428	760,599	734,062	700,760	658,052	393,530	692,561	9,238,783
	b. Recoverable costs allocated to Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Energy Jurisdictional Factor		0.99120	0.99240	0.99560	0.99550	0.99520	0.99280	0.99480	0.99440	0.99390	0.99370	0.99410	0.99490	
10	Demand Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)		377,343	513,399	1,428,256	1,229,301	897,014	824,449	756,644	729,952	696,485	653,906	391,208	689,029	9,186,987
12	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)		$ 377,343	$ 513,399	$ 1,428,256	$ 1,229,301	$ 897,014	$ 824,449	$ 756,644	$ 729,952	$ 696,485	$ 653,906	$ 391,208	$ 689,029	$ 9,186,987

Notes:
(A) Line 3 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$283	$283	$283	$283	$283	$283	$1,700
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	
3	Less: Accumulated Depreciation		(1,324)	(1,350)	(1,376)	(1,402)	(1,428)	(1,454)	(1,480)	(1,506)	(1,532)	(1,558)	(1,584)	(1,610)	(1,636)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	283	567	850	1,133	1,417	1,700	
5	Net Investment (Lines 2 + 3 + 4)		$8,875	$8,849	$8,823	$8,797	$8,771	$8,745	$8,719	$8,976	$9,234	$9,491	$9,748	$10,006	$10,263	
6	Average Net Investment			8,862	8,836	8,810	8,784	8,758	8,732	8,848	9,105	9,362	9,620	9,877	10,134	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		22	22	22	22	22	21	22	22	23	24	24	25	$271
	b. Equity Component Grossed Up For Taxes	8.02%		59	59	59	59	59	58	59	61	63	64	66	68	734
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.10%		26	26	26	26	26	26	26	26	26	26	26	26	312
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.009674		8	8	8	8	8	8	8	8	8	8	8	8	96
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$115	$115	$115	$115	$115	$113	$115	$117	$120	$122	$124	$127	$1,413
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$115	$115	$115	$115	$115	$113	$115	$117	$120	$122	$124	$127	$1,413
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)			0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			115	115	115	115	115	113	115	117	120	122	124	127	1,408
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$115	$115	$115	$115	$115	$113	$115	$117	$120	$122	$124	$127	$1,408

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc Tax multiplier = 1.628002). Based on 2010 rate case Oder PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Base (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		(21,136)	(21,432)	(21,728)	(22,024)	(22,320)	(22,616)	(22,912)	(23,208)	(23,504)	(23,800)	(24,096)	(24,392)	(24,688)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$147,805	$147,509	$147,213	$146,917	$146,621	$146,325	$146,029	$145,733	$145,437	$145,141	$144,845	$144,549	$144,253	
6	Average Net Investment			147,657	147,361	147,065	146,769	146,473	146,177	145,881	145,585	145,289	144,993	144,697	144,401	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		363	363	362	361	360	360	359	358	357	357	356	355	4,311
	b. Equity Component Grossed Up For Taxes	8.02%		987	985	983	981	979	977	975	973	971	969	967	965	11,712
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.10%		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007880		111	111	111	111	111	111	111	111	111	111	111	111	1,332
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,757	$1,755	$1,752	$1,749	$1,746	$1,744	$1,741	$1,738	$1,735	$1,733	$1,730	$1,727	$20,907
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,757	$1,755	$1,752	$1,749	$1,746	$1,744	$1,741	$1,738	$1,735	$1,733	$1,730	$1,727	$20,907
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			1,611	1,609	1,606	1,604	1,601	1,599	1,596	1,593	1,591	1,589	1,586	1,583	19,168
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,611	$1,609	$1,606	$1,604	$1,601	$1,599	$1,596	$1,593	$1,591	$1,589	$1,586	$1,583	$19,168

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc Tax multiplier = 1.628002). Based on 2010 rate case Oder PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation		(12,041)	(12,244)	(12,447)	(12,650)	(12,853)	(13,056)	(13,259)	(13,462)	(13,665)	(13,868)	(14,071)	(14,274)	(14,477)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$63,965	$63,762	$63,559	$63,356	$63,153	$62,950	$62,747	$62,544	$62,341	$62,138	$61,935	$61,732	$61,529	
6	Average Net Investment			63,864	63,661	63,458	63,255	63,052	62,849	62,646	62,443	62,240	62,037	61,834	61,631	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		157	157	156	156	155	155	154	154	153	153	152	152	1,854
	b. Equity Component Grossed Up For Taxes	8.02%		427	426	424	423	422	420	419	418	416	415	413	412	5,035
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.20%		203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.010140		64	64	64	64	64	64	64	64	64	64	64	64	768
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$851	$850	$847	$846	$844	$842	$840	$839	$836	$835	$832	$831	$10,093
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$851	$850	$847	$846	$844	$842	$840	$839	$836	$835	$832	$831	$10,093
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			549	548	546	546	545	543	542	541	539	539	537	536	6,512
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$549	$548	$546	$546	$545	$543	$542	$541	$539	$539	$537	$536	$6,512

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: MODULAR COOLING TOWERS - Base (Project 11)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	
3	Less: Accumulated Depreciation		(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes	8.02%		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
8	Investment Expenses															
	a. Depreciation (C)	20.00%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007880		437	437	437	437	437	437	437	437	437	437	437	437	5,244
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$5,244
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$5,244
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			401	401	401	401	401	401	401	401	401	401	401	401	4,808
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$401	$401	$401	$401	$401	$401	$401	$401	$401	$401	$401	$401	$4,808

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 060162-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CRYSTAL RIVER THERMAL DISCHARGE COMPLIANCE PROJECT - AFUDC - Base (Project 11.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$2,899	$262,420	$9,923	$60,692	$32,954	$46,812	$24,671	$24,671	$24,671	$24,671	$24,671	$24,671	$563,727
	b. Clearings to Plant			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	
	d. Other (A)			100,526	100,295	101,689	103,267	104,150	104,965	106,069	106,879	107,694	108,515	109,340	110,170	
2	Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation		(14,722)	(15,234)	(15,746)	(16,258)	(16,770)	(17,282)	(17,794)	(18,306)	(18,818)	(19,330)	(19,842)	(20,354)	(20,866)	
4	CWIP - AFUDC Bearing		16,074,201	16,177,626	16,540,341	16,651,953	16,815,912	16,953,016	17,104,794	17,235,534	17,367,084	17,499,450	17,632,636	17,766,647	17,901,488	
5	Net Investment (Lines 2 + 3 + 4)		$16,421,214	$16,524,127	$16,886,330	$16,997,431	$17,160,877	$17,297,470	$17,448,735	$17,578,964	$17,710,002	$17,841,856	$17,974,529	$18,108,028	$18,242,358	
6	Average Net Investment (B)			$346,758	$346,246	$345,734	$345,222	$344,710	$344,198	$343,686	$343,174	$342,662	$342,150	$341,638	$341,126	
7	Return on Average Net Investment (C)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		853	852	851	849	848	847	846	844	843	842	841	839	10,155
	b. Equity Component Grossed Up For Taxes	8.02%		2,318	2,315	2,312	2,308	2,305	2,301	2,298	2,295	2,291	2,288	2,284	2,281	27,596
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (D)			512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	N/A
	d. Property Taxes (E)			280	280	280	280	280	280	280	280	280	280	280	280	3,360
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,963	$3,959	$3,955	$3,949	$3,945	$3,940	$3,936	$3,931	$3,926	$3,922	$3,917	$3,912	$47,255
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$3,963	$3,959	$3,955	$3,949	$3,945	$3,940	$3,936	$3,931	$3,926	$3,922	$3,917	$3,912	$47,255
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
12	Retail Energy-Related Recoverable Costs (F)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (G)			3,633	3,630	3,626	3,621	3,617	3,612	3,609	3,604	3,599	3,596	3,591	3,587	43,325
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$3,633	$3,630	$3,626	$3,621	$3,617	$3,612	$3,609	$3,604	$3,599	$3,596	$3,591	$3,587	$43,325

Notes:
(A) AFUDC rate reflected within Docket 100134-EI per Order PSC-10-0604-PAA-EI.
(B) Line represents the Average Net Investment excluding AFUDC interest-bearing CWIP projects. Refer to Capital Program Detail for Average Net Investment Return on which Line 7 is calculated.
(C) Weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Depreciation calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: NPDES (Project 16)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 5,735	$ 12,657	$ 76,949	$ 26,110	$ 21	$ 16,804	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 900,000	$ 825,033	$ 2,263,310
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	2,323,361	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	2,323,361	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(3,195)	
4	CWIP - Non-Interest Bearing		60,051	65,786	78,443	155,393	181,503	181,524	198,328	298,328	398,328	498,328	598,328	1,498,328	0	
5	Net Investment (Lines 2 + 3 + 4)		$ 60,051	$ 65,786	$ 78,443	$ 155,393	$ 181,503	$ 181,524	$ 198,328	$ 298,328	$ 398,328	$ 498,328	$ 598,328	$ 1,498,328	$ 2,320,166	
6	Average Net Investment			62,919	72,115	116,918	168,448	181,513	189,926	248,328	348,328	448,328	548,328	1,048,328	1,909,247	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		155	177	288	414	447	467	611	857	1,103	1,349	2,579	4,697	13,144
	b. Equity Component Grossed Up For Taxes	8.02%		421	482	782	1,126	1,214	1,270	1,660	2,329	2,998	3,666	7,009	12,766	35,723
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.30%		0	0	0	0	0	0	0	0	0	0	0	3,195	3,195
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.010140		0	0	0	0	0	0	0	0	0	0	0	1,963	1,963
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$576	$659	$1,070	$1,540	$1,661	$1,737	$2,271	$3,186	$4,101	$5,015	$9,588	$22,621	$54,025
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$576	$659	$1,070	$1,540	$1,661	$1,737	$2,271	$3,186	$4,101	$5,015	$9,588	$22,621	$54,025
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	0.64519	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			372	425	690	994	1,072	1,121	1,465	2,056	2,646	3,236	6,166	14,595	34,856
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$372	$425	$690	$994	$1,072	$1,121	$1,465	$2,056	$2,646	$3,236	$6,186	$14,595	$34,856

(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury & Air Toxic Standards (MATS) - Energy (Crystal River 4 & 5) (Project 17)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$930	$400,000	$100,000	$187,500	$187,500	$187,500	$187,500	$1,250,930
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	930	400,930	500,930	688,430	875,930	1,063,430	1,250,930	
5	Net Investment (Lines 2 + 3 + 4)		$0	$0	$0	$0	$0	$0	$930	$400,930	$500,930	$688,430	$875,930	$1,063,430	$1,250,930	
6	Average Net Investment			$0	$0	$0	$0	$0	$465	$200,930	$450,930	$594,680	$782,180	$969,680	$1,157,180	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	1	494	1,109	1,463	1,924	2,386	2,847	10,224
	b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	0	3	1,343	3,015	3,976	5,230	6,483	7,737	27,787
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.50%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.008310		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$0	$0	$0	$0	$0	$4	$1,837	$4,124	$5,439	$7,154	$8,869	$10,584	$38,011
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	4	1,837	4,124	5,439	7,154	8,869	10,584	38,011
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Energy Jurisdictional Factor			0.99120	0.99240	0.99560	0.99550	0.99520	0.99280	0.99480	0.99440	0.99390	0.99370	0.99410	0.99490	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	4	1,827	4,101	5,406	7,109	8,817	10,530	37,794
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$4	$1,827	$4,101	$5,406	$7,109	$8,817	$10,530	$37,794

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated / Actual Amount
January 2012 through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury & Air Toxic Standards (MATS) - Energy - (Anclote Gas Conversion) (Project 17.1)
(In Dollars)

Line	Description	Beginning of Period Amount	Actual January 12	Actual February 12	Actual March 12	Actual April 12	Actual May 12	Actual June 12	Estimated July 12	Estimated August 12	Estimated September 12	Estimated October 12	Estimated November 12	Estimated December 12	End of Period Total
1	Investments														
	a. Expenditures/Additions		$ -	$ -	$ 318,693	$ 2,508,190	$ 2,905,516	$ 2,456,047	$ 1,908,671	$ 4,042,384	$ 1,419,886	$ 3,920,570	$ 1,149,401	$ 1,557,515	$22,186,874
	b. Clearings to Plant		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	
	d. Other (A)		0	0	109	10,098	20,011	41,909	55,243	73,413	90,226	106,775	122,612	131,461	
2	Plant-in-Service/Depreciation Base	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - AFUDC Interest Bearing	0	0	0	318,802	2,837,090	5,762,617	8,260,573	10,224,487	14,340,284	15,850,396	19,877,741	21,149,754	22,838,730	
5	Net Investment (Lines 2 + 3 + 4)	$0	$0	$0	$318,802	$2,837,090	$5,762,617	$8,260,573	$10,224,487	$14,340,284	$15,850,396	$19,877,741	$21,149,754	$22,838,730	
6	Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7	Return on Average Net Investment (B)														
	a. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes 8.02%		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
8	Investment Expenses														
	a. Depreciation (C) 2.20%		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. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.008310		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Energy Jurisdictional Factor		0.99120	0.99240	0.99560	0.99550	0.99520	0.99280	0.99480	0.99440	0.99390	0.99370	0.99410	0.99490	
11	Demand Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) AFUDC rate reflected within Docket 100134-EI per Order PSC-10-0604-PAA-E (AFUDC Monthly Compound Rat 0.5995%
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Form 42-8E Appendix

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2012 through December 2012

Variance Report of Capital Investment Projects - Capital Expenditures
(In Dollars)

Line		(1) Estimated/ Actual	(2) Amended Projection	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
3	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$ 6	$ 0	$ 6	100%
4.1	Above Ground Tank Secondary Containment - Peaking	5,267	0	5,267	100%
4.2	Above Ground Tank Secondary Containment - Base	0	0	0	0%
4.3	Above Ground Tank Secondary Containment - Intermediate	0	0	0	0%
5	SO2/NOx Emissions Allowances - Energy (A)	21,403,584	18,627,860	2,775,724	15%
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0%
7.2	CAIR CT's - Peaking	0	0	0	0%
7.3	CAMR Crystal River - Base	0	0	0	0%
7.4	CAIR Crystal River AFUDC - Base	22,541,982	27,947,520	(5,405,538)	-19%
7.4	CAIR Crystal River AFUDC - Energy (A)	874,032	591,276	282,756	48%
9	Sea Turtle - Coastal Street Lighting -Distribution	1,700	0	1,700	100%
10.1	Underground Storage Tanks-Base	0	0	0	0%
10.2	Underground Storage Tanks-Intermediate	0	0	0	0%
11	Modular Cooling Towers - Base	0	0	0	0%
11.1	Thermal Discharge Permanent Cooling Tower - Base	563,727	0	563,727	100%
16	National Pollutant Discharge Elimination System (NPDES)-Intermediate	2,263,310	2,261,704	1,606	0%
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Base	1,250,930	0	1,250,930	100%
17.1	Mercury & Air Toxic Standards (MATS) Anclote- Intermediate	22,186,874	0	22,186,874	100%
2	Total Investment Projects - Capital Expenditures	$ 71,091,412	$ 49,428,360	$ 21,663,052	44%

Notes:
(A) Working Capital

PROGRESS ENERGY FLORIDA

Form 42-9E

Environmental Cost Recovery Clause (ECRC)

Calculation of the Current Period Estimated/Actual Amount

January 2012 through December 2012

Progress Energy Florida Capital Structure and Cost Rates

Class of Capital	Retail Amount	Stafff Adjusted	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$ 2,916,026	$ 2,945,782	46.74%	0.10500	4.908%	7.990%
PS	21,239	21,456	0.34%	0.04510	0.015%	0.025%
LTD	2,817,708	2,846,460	45.17%	0.06178	2.790%	2.790%
STD	41,245	41,666	0.66%	0.03720	0.025%	0.025%
CD-Active	144,119	145,590	2.31%	0.05950	0.137%	0.137%
CD-Inactive	1,457	1,472	0.02%	0.00000	0.000%	0.000%
ADIT	415,881	420,125	6.67%	0.00000	0.000%	0.000%
FAS 109	(122,914)	(124,168)	-1.97%	0.00000	0.000%	0.000%
ITC	3,857	3,896	0.06%	0.08360	0.005%	0.008%
Total	$ 6,238,618	$ 6,302,278	100.00%		7.881%	10.976%
				Total Debt	2.95%	2.95%
				Total Equity	4.93%	8.02%

Source: Per Staff 13-Month Average Capital Structure worksheet - Schedule 2 REVISED - handed out at 1/11/10 Rate Case Agenda - Docket No. 090079-EI

Rationale: The Company is using the currently approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Docket No. 120007-EI
Progress Energy Florida, Inc.
Witness T.G. Foster
Exhibit No. _____ (TGF-1)
Page 28 of 28

Progress Energy Florida, Inc.
Environmental Cost Recovery
Capital Program Detail

January 2012 - December 2012

Docket No. 120007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 29
PARTY Progress Energy Florida
DESCRIPTION Thomas Foster (TGF- 2) Capital Program Detail
DATE January 2012 - December 2012

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3	Less: Accumulated Depreciation		(6,793)	(6,847)	(6,901)	(6,955)	(7,009)	(7,063)	(7,117)	(7,171)	(7,225)	(7,279)	(7,333)	(7,387)	(7,441)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		27,160	27,106	27,052	26,998	26,944	26,890	26,836	26,782	26,726	26,674	26,620	26,566	26,512	
6	Average Net Investment			27,133	27,079	27,025	26,971	26,917	26,863	26,809	26,755	26,701	26,647	26,593	26,539	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		67	67	66	66	66	66	66	66	66	66	65	65	792
	b. Equity Component Grossed Up For Taxes	8.02%		181	181	181	180	180	180	179	179	179	178	178	177	2,153
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.90%		54	54	54	54	54	54	54	54	54	54	54	54	648
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009939		28	28	28	28	28	28	28	28	28	28	28	28	336
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			330	330	329	328	328	328	327	327	327	326	325	324	3,929
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			330	330	329	328	328	328	327	327	327	326	325	324	3,929

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	
3	Less: Accumulated Depreciation		(658,979)	(664,700)	(670,421)	(676,142)	(681,863)	(687,584)	(693,305)	(699,026)	(704,747)	(710,468)	(716,189)	(721,910)	(727,631)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,981,657	1,975,936	1,970,215	1,964,494	1,958,773	1,953,052	1,947,331	1,941,610	1,935,889	1,930,168	1,924,447	1,918,726	1,913,005	
6	Average Net Investment			1,978,797	1,973,076	1,967,355	1,961,634	1,955,913	1,950,192	1,944,471	1,938,750	1,933,029	1,927,308	1,921,587	1,915,866	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,868	4,854	4,840	4,826	4,812	4,798	4,784	4,770	4,756	4,742	4,728	4,714	57,492
	b. Equity Component Grossed Up For Taxes	8.02%		13,231	13,192	13,154	13,116	13,078	13,039	13,001	12,963	12,925	12,886	12,848	12,810	156,243
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	68,652
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009939		2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	26,244
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			26,007	25,954	25,902	25,850	25,798	25,745	25,693	25,641	25,589	25,536	25,484	25,432	308,631
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			26,007	25,954	25,902	25,850	25,798	25,745	25,693	25,641	25,589	25,536	25,484	25,432	308,631

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	
3	Less: Accumulated Depreciation		(85,372)	(87,342)	(89,312)	(91,282)	(93,252)	(95,222)	(97,192)	(99,162)	(101,132)	(103,102)	(105,072)	(107,042)	(109,012)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		824,034	822,064	820,094	818,124	816,154	814,184	812,214	810,244	808,274	806,304	804,334	802,364	800,394	
6	Average Net Investment			823,049	821,079	819,109	817,139	815,169	813,199	811,229	809,259	807,289	805,319	803,349	801,379	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,025	2,020	2,015	2,010	2,006	2,001	1,996	1,991	1,986	1,981	1,976	1,972	23,979
	b. Equity Component Grossed Up For Taxes	8.02%		5,503	5,490	5,477	5,464	5,450	5,437	5,424	5,411	5,398	5,385	5,371	5,358	65,168
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	23,640
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009939		753	753	753	753	753	753	753	753	753	753	753	753	9,036
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,251	10,233	10,215	10,197	10,179	10,161	10,143	10,125	10,107	10,089	10,070	10,053	121,823
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			10,251	10,233	10,215	10,197	10,179	10,161	10,143	10,125	10,107	10,089	10,070	10,053	121,823

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			6	0	0	0	0	0	0	0	0	0	0	0	6
	b. Clearings to Plant			6	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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		135,068	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	
3	Less: Accumulated Depreciation		(192)	(575)	(958)	(1,341)	(1,724)	(2,107)	(2,490)	(2,873)	(3,256)	(3,639)	(4,022)	(4,405)	(4,788)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		134,876	134,499	134,116	133,733	133,350	132,967	132,584	132,201	131,818	131,435	131,052	130,669	130,286	
6	Average Net Investment			134,688	134,308	133,925	133,542	133,159	132,776	132,393	132,010	131,627	131,244	130,861	130,478	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		331	330	329	329	328	327	326	325	324	323	322	321	3,915
	b. Equity Component Grossed Up For Taxes	8.02%		901	898	895	893	890	888	885	883	880	878	875	872	10,638
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.40%		383	383	383	383	383	383	383	383	383	383	383	383	4,596
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009939		112	112	112	112	112	112	112	112	112	112	112	112	1,344
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,727	1,723	1,719	1,717	1,713	1,710	1,706	1,703	1,699	1,696	1,692	1,688	20,493
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,727	1,723	1,719	1,717	1,713	1,710	1,706	1,703	1,699	1,696	1,692	1,688	20,493

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	
3	Less: Accumulated Depreciation		(158,079)	(163,202)	(168,325)	(173,448)	(178,571)	(183,694)	(188,817)	(193,940)	(199,063)	(204,186)	(209,309)	(214,432)	(219,555)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,908,520	1,903,397	1,898,274	1,893,151	1,888,028	1,882,905	1,877,782	1,872,659	1,867,536	1,862,413	1,857,290	1,852,167	1,847,044	
6	Average Net Investment			1,905,959	1,900,836	1,895,713	1,890,590	1,885,467	1,880,344	1,875,221	1,870,098	1,864,975	1,859,852	1,854,729	1,849,606	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,689	4,677	4,664	4,651	4,639	4,626	4,614	4,601	4,588	4,576	4,563	4,551	55,439
	b. Equity Component Grossed Up For Taxes	8.02%		12,744	12,709	12,675	12,641	12,607	12,572	12,538	12,504	12,470	12,435	12,401	12,367	150,663
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.98%		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.012430		2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	25,692
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			24,697	24,650	24,603	24,556	24,510	24,462	24,416	24,369	24,322	24,275	24,228	24,182	293,270
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			24,697	24,650	24,603	24,556	24,510	24,462	24,416	24,369	24,322	24,275	24,228	24,182	293,270

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	
3	Less: Accumulated Depreciation		(115,671)	(119,356)	(123,041)	(126,726)	(130,411)	(134,096)	(137,781)	(141,466)	(145,151)	(148,836)	(152,521)	(156,206)	(159,891)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,358,130	1,354,445	1,350,760	1,347,075	1,343,390	1,339,705	1,336,020	1,332,335	1,328,650	1,324,965	1,321,280	1,317,595	1,313,910	
6	Average Net Investment			1,356,288	1,352,603	1,348,918	1,345,233	1,341,548	1,337,863	1,334,178	1,330,493	1,326,808	1,323,123	1,319,438	1,315,753	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		3,337	3,328	3,319	3,310	3,301	3,292	3,282	3,273	3,264	3,255	3,246	3,237	39,444
	b. Equity Component Grossed Up For Taxes	8.02%		9,068	9,044	9,019	8,994	8,970	8,945	8,921	8,896	8,871	8,847	8,822	8,797	107,194
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	14,940
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			17,335	17,302	17,268	17,234	17,201	17,167	17,133	17,099	17,065	17,032	16,998	16,964	205,798
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			17,335	17,302	17,268	17,234	17,201	17,167	17,133	17,099	17,065	17,032	16,998	16,964	205,798

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation		(395,459)	(404,598)	(413,737)	(422,876)	(432,015)	(441,154)	(450,293)	(459,432)	(468,571)	(477,710)	(486,849)	(495,988)	(505,127)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,266,205	1,257,066	1,247,927	1,238,788	1,229,649	1,220,510	1,211,371	1,202,232	1,193,093	1,183,954	1,174,815	1,165,676	1,156,537	
6	Average Net Investment			1,261,636	1,252,497	1,243,358	1,234,219	1,225,080	1,215,941	1,206,802	1,197,663	1,188,524	1,179,385	1,170,246	1,161,107	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		3,104	3,082	3,059	3,037	3,014	2,992	2,969	2,947	2,924	2,902	2,879	2,857	35,766
	b. Equity Component Grossed Up For Taxes	8.02%		8,436	8,374	8,313	8,252	8,191	8,130	8,069	8,008	7,947	7,886	7,824	7,763	97,193
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.80%		9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008990		1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	14,940
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			21,924	21,840	21,756	21,673	21,589	21,506	21,422	21,339	21,255	21,172	21,087	21,004	257,567
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			21,924	21,840	21,756	21,673	21,589	21,506	21,422	21,339	21,255	21,172	21,087	21,004	257,567

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	
3	Less: Accumulated Depreciation		(38,345)	(39,061)	(39,777)	(40,493)	(41,209)	(41,925)	(42,641)	(43,357)	(44,073)	(44,789)	(45,505)	(46,221)	(46,937)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		140,593	139,877	139,161	138,445	137,729	137,013	136,297	135,581	134,865	134,149	133,433	132,717	132,001	
6	Average Net Investment			140,235	139,519	138,803	138,087	137,371	136,655	135,939	135,223	134,507	133,791	133,075	132,359	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		345	343	341	340	338	336	334	333	331	329	327	326	4,023
	b. Equity Component Grossed Up For Taxes	8.02%		938	933	928	923	918	914	909	904	899	895	890	885	10,936
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.80%		718	716	718	716	716	716	716	716	716	716	716	716	8,592
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930		133	133	133	133	208	148	148	148	148	148	148	148	1,776
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,132	2,125	2,118	2,112	2,180	2,114	2,107	2,101	2,094	2,088	2,081	2,075	25,327
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,132	2,125	2,118	2,112	2,180	2,114	2,107	2,101	2,094	2,088	2,081	2,075	25,327

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3	Less: Accumulated Depreciation		(89,420)	(91,246)	(93,072)	(94,898)	(96,724)	(98,550)	(100,376)	(102,202)	(104,028)	(105,854)	(107,680)	(109,506)	(111,332)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		640,875	639,049	637,223	635,397	633,571	631,745	629,919	628,093	626,267	624,441	622,615	620,789	618,963	
6	Average Net Investment			639,962	638,136	636,310	634,484	632,658	630,832	629,006	627,180	625,354	623,528	621,702	619,876	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,575	1,570	1,566	1,561	1,557	1,552	1,548	1,543	1,539	1,534	1,530	1,525	18,600
	b. Equity Component Grossed Up For Taxes	8.02%		4,279	4,267	4,254	4,242	4,230	4,218	4,206	4,193	4,181	4,169	4,157	4,145	50,541
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	21,912
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		617	617	617	617	617	617	617	617	617	617	617	617	7,404
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			8,297	8,280	8,263	8,246	8,230	8,213	8,197	8,179	8,163	8,146	8,130	8,113	98,457
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			8,297	8,280	8,263	8,246	8,230	8,213	8,197	8,179	8,163	8,146	8,130	8,113	98,457

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(152,808)	(155,660)	(158,512)	(161,364)	(164,216)	(167,068)	(169,920)	(172,772)	(175,624)	(178,476)	(181,328)	(184,180)	(187,032)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		884,391	881,539	878,687	875,835	872,983	870,131	867,279	864,427	861,575	858,723	855,871	853,019	850,167	
6	Average Net Investment			882,965	880,113	877,261	874,409	871,557	868,705	865,853	863,001	860,149	857,297	854,445	851,593	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,172	2,165	2,158	2,151	2,144	2,137	2,130	2,123	2,116	2,109	2,102	2,095	25,602
	b. Equity Component Grossed Up For Taxes	8.02%		5,904	5,885	5,866	5,846	5,827	5,808	5,789	5,770	5,751	5,732	5,713	5,694	69,585
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.30%		2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008590		742	742	742	742	742	742	742	742	742	742	742	742	8,904
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			11,670	11,644	11,618	11,591	11,565	11,539	11,513	11,487	11,461	11,435	11,409	11,383	138,315
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			11,670	11,644	11,618	11,591	11,565	11,539	11,513	11,487	11,461	11,435	11,409	11,383	138,315

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			(6,417)	10,309	3,083	(1,706)	(1)	0	0	0	0	0	0	0	5,267
	b. Clearings to Plant			(6,417)	10,309	3,083	(1,706)	(1)	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-In-Service/Depreciation Base		3,611,638	3,605,220	3,615,528	3,618,611	3,616,905	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	
3	Less: Accumulated Depreciation		(163,852)	(171,663)	(179,497)	(187,337)	(195,174)	(203,011)	(210,848)	(218,685)	(226,522)	(234,359)	(242,196)	(250,033)	(257,870)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		3,447,785	3,433,557	3,436,032	3,431,274	3,421,731	3,413,893	3,406,056	3,398,219	3,390,382	3,382,545	3,374,708	3,366,871	3,359,034	
6	Average Net Investment			3,440,671	3,434,794	3,433,653	3,426,503	3,417,812	3,409,974	3,402,137	3,394,300	3,386,463	3,378,626	3,370,789	3,362,952	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		8,465	8,451	8,448	8,430	8,409	8,390	8,370	8,351	8,332	8,312	8,293	8,274	100,525
	b. Equity Component Grossed Up For Taxes	8.02%		23,005	22,966	22,958	22,910	22,852	22,800	22,747	22,695	22,643	22,590	22,538	22,485	273,189
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		7,811	7,834	7,840	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	94,018
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.012430		3,734	3,745	3,748	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	44,950
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			43,015	42,996	42,994	42,924	42,845	42,774	42,701	42,630	42,559	42,486	42,415	42,343	512,682
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			43,015	42,996	42,994	42,924	42,845	42,774	42,701	42,630	42,559	42,486	42,415	42,343	512,682

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Unitversity of Florida (Project 4.1h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Bese		141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation		(42,990)	(43,226)	(43,462)	(43,698)	(43,934)	(44,170)	(44,406)	(44,642)	(44,878)	(45,114)	(45,350)	(45,586)	(45,822)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		98,444	98,208	97,972	97,736	97,500	97,264	97,028	96,792	96,556	96,320	96,084	95,848	95,612	
6	Average Net Investment			98,326	98,090	97,854	97,618	97,382	97,146	96,910	96,674	96,438	96,202	95,966	95,730	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		242	241	241	240	240	239	238	238	237	237	236	236	2,865
	b. Equity Component Grossed Up For Taxes	8.02%		657	656	654	653	651	650	648	646	645	643	642	640	7,785
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.00%		236	236	236	236	236	236	236	236	236	236	236	236	2,832
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.014450		170	170	170	170	170	170	170	170	170	170	170	170	2,040
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,305	1,303	1,301	1,299	1,297	1,295	1,292	1,290	1,288	1,286	1,284	1,282	15,522
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,305	1,303	1,301	1,299	1,297	1,295	1,292	1,290	1,288	1,286	1,284	1,282	15,522

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	
3	Less: Accumulated Depreciation		(54,444)	(56,221)	(57,998)	(59,775)	(61,552)	(63,329)	(65,106)	(66,883)	(68,660)	(70,437)	(72,214)	(73,991)	(75,768)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		340,524	338,747	336,970	335,193	333,416	331,639	329,862	328,085	326,308	324,531	322,754	320,977	319,200	
6	Average Net Investment			339,635	337,858	336,081	334,304	332,527	330,750	328,973	327,196	325,419	323,642	321,865	320,088	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		836	831	827	822	818	814	809	805	801	796	792	788	9,739
	b. Equity Component Grossed Up For Taxes	8.02%		2,271	2,259	2,247	2,235	2,223	2,211	2,200	2,188	2,176	2,164	2,152	2,140	26,466
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.40%		1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	21,324
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		334	334	334	334	334	334	334	334	334	334	334	334	4,008
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,218	5,201	5,185	5,168	5,152	5,136	5,120	5,104	5,088	5,071	5,055	5,039	61,537
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			5,218	5,201	5,185	5,168	5,152	5,136	5,120	5,104	5,088	5,071	5,055	5,039	61,537

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation		(10,995)	(11,097)	(11,199)	(11,301)	(11,403)	(11,505)	(11,607)	(11,709)	(11,811)	(11,913)	(12,015)	(12,117)	(12,219)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		22,097	21,995	21,893	21,791	21,689	21,587	21,485	21,383	21,281	21,179	21,077	20,975	20,873	
6	Average Net Investment			22,046	21,944	21,842	21,740	21,638	21,536	21,434	21,332	21,230	21,128	21,026	20,924	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		54	54	54	53	53	53	53	52	52	52	52	51	633
	b. Equity Component Grossed Up For Taxes	8.02%		147	147	146	145	145	144	143	143	142	141	141	140	1,724
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.70%		102	102	102	102	102	102	102	102	102	102	102	102	1,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		22	22	22	22	22	22	22	22	22	22	22	22	264
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			325	325	324	322	322	321	320	319	318	317	317	315	3,845
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			325	325	324	322	322	321	320	319	318	317	317	315	3,845

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	
3	Less: Accumulated Depreciation		(204,863)	(210,807)	(216,751)	(222,695)	(228,639)	(234,583)	(240,527)	(246,471)	(252,415)	(258,359)	(264,303)	(270,247)	(276,191)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		2,648,316	2,642,372	2,636,428	2,630,484	2,624,540	2,618,596	2,612,652	2,606,708	2,600,764	2,594,820	2,588,876	2,582,932	2,576,988	
6	Average Net Investment			2,645,344	2,639,400	2,633,456	2,627,512	2,621,568	2,615,624	2,609,680	2,603,736	2,597,792	2,591,848	2,585,904	2,579,960	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		6,506	6,494	6,479	6,465	6,450	6,435	6,421	6,406	6,391	6,377	6,362	6,348	77,136
	b. Equity Component Grossed Up For Taxes	8.02%		17,687	17,648	17,608	17,568	17,528	17,489	17,449	17,409	17,369	17,330	17,290	17,250	209,625
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	71,328
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		1,874	1,874	1,874	1,874	1,874	1,874	1,874	1,874	1,874	1,874	1,874	1,874	22,488
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			32,013	31,960	31,905	31,851	31,796	31,742	31,688	31,633	31,578	31,525	31,470	31,416	380,577
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			32,013	31,960	31,905	31,851	31,796	31,742	31,688	31,633	31,578	31,525	31,470	31,416	380,577

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(34,986)	(35,516)	(36,050)	(36,582)	(37,114)	(37,646)	(38,178)	(38,710)	(39,242)	(39,774)	(40,306)	(40,838)	(41,370)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		255,312	254,780	254,248	253,716	253,184	252,652	252,120	251,588	251,056	250,524	249,992	249,460	248,928	
6	Average Net Investment			255,046	254,514	253,982	253,450	252,918	252,386	251,854	251,322	250,790	250,258	249,726	249,194	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		627	626	625	624	622	621	620	618	617	616	614	613	7,443
	b. Equity Component Grossed Up For Taxes	8.02%		1,705	1,702	1,698	1,695	1,691	1,687	1,684	1,680	1,677	1,673	1,670	1,666	20,228
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.20%		532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008310		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,065	3,061	3,056	3,052	3,046	3,041	3,037	3,031	3,027	3,022	3,017	3,012	36,467
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,065	3,061	3,056	3,052	3,046	3,041	3,037	3,031	3,027	3,022	3,017	3,012	36,467

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3	Less: Accumulated Depreciation		(14,249)	(14,653)	(15,057)	(15,461)	(15,865)	(16,269)	(16,673)	(17,077)	(17,481)	(17,885)	(18,289)	(18,693)	(19,097)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		147,505	147,101	146,697	146,293	145,889	145,485	145,081	144,677	144,273	143,869	143,465	143,061	142,657	
6	Average Net Investment			147,303	146,899	146,495	146,091	145,687	145,283	144,879	144,475	144,071	143,667	143,263	142,859	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		362	361	360	359	358	357	356	355	354	353	352	351	4,278
	b. Equity Component Grossed Up For Taxes	8.02%		985	982	979	977	974	971	969	966	963	961	958	955	11,640
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		404	404	404	404	404	404	404	404	404	404	404	404	4,848
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930		134	134	134	134	134	134	134	134	134	134	134	134	1,608
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,885	1,881	1,877	1,874	1,870	1,866	1,863	1,859	1,855	1,852	1,848	1,844	22,374
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,885	1,881	1,877	1,874	1,870	1,866	1,863	1,859	1,855	1,852	1,848	1,844	22,374

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3	Less: Accumulated Depreciation		(28,081)	(28,448)	(28,815)	(29,182)	(29,549)	(29,916)	(30,283)	(30,650)	(31,017)	(31,384)	(31,751)	(32,118)	(32,485)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		247,266	246,899	246,532	246,165	245,798	245,431	245,064	244,697	244,330	243,963	243,596	243,229	242,862	
6	Average Net Investment			247,083	246,716	246,349	245,982	245,615	245,248	244,881	244,514	244,147	243,780	243,413	243,046	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		608	607	606	605	604	603	602	602	601	600	599	598	7,235
	b. Equity Component Grossed Up For Taxes	8.02%		1,652	1,650	1,647	1,645	1,642	1,640	1,637	1,635	1,632	1,630	1,628	1,625	19,663
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.60%		367	367	367	367	367	367	367	367	367	367	367	367	4,404
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		233	233	233	233	233	233	233	233	233	233	233	233	2,795
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,860	2,857	2,853	2,850	2,846	2,843	2,839	2,837	2,833	2,830	2,827	2,823	34,098
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,860	2,857	2,853	2,850	2,846	2,843	2,839	2,837	2,833	2,830	2,827	2,823	34,098

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation		(20,223)	(20,604)	(20,985)	(21,366)	(21,747)	(22,128)	(22,509)	(22,890)	(23,271)	(23,652)	(24,033)	(24,414)	(24,795)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		178,765	178,384	178,003	177,622	177,241	176,860	176,479	176,098	175,717	175,336	174,955	174,574	174,193	
6	Average Net Investment			178,575	178,194	177,813	177,432	177,051	176,670	176,289	175,908	175,527	175,146	174,765	174,384	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		439	438	437	437	436	435	434	433	432	431	430	429	5,211
	b. Equity Component Grossed Up For Taxes	8.02%		1,194	1,191	1,189	1,186	1,184	1,181	1,179	1,176	1,174	1,171	1,169	1,166	14,160
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.30%		381	381	381	381	381	381	381	381	381	381	381	381	4,572
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		168	168	168	168	168	168	168	168	168	168	168	168	2,016
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,182	2,178	2,175	2,172	2,169	2,165	2,162	2,158	2,155	2,151	2,148	2,144	25,959
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,182	2,178	2,175	2,172	2,169	2,165	2,162	2,158	2,155	2,151	2,148	2,144	25,959

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation		(11,631)	(11,850)	(12,069)	(12,288)	(12,507)	(12,726)	(12,945)	(13,164)	(13,383)	(13,602)	(13,821)	(14,040)	(14,259)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		76,036	75,817	75,598	75,379	75,160	74,941	74,722	74,503	74,284	74,065	73,846	73,627	73,408	
6	Average Net Investment			75,928	75,707	75,488	75,269	75,050	74,831	74,612	74,393	74,174	73,955	73,736	73,517	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		187	186	186	185	185	184	184	183	182	182	181	181	2,206
	b. Equity Component Grossed Up For Taxes	8.02%		508	506	505	503	502	500	499	497	496	494	493	492	5,995
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.012430		91	91	91	91	91	91	91	91	91	91	91	91	1,092
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,005	1,002	1,001	998	997	994	993	990	988	986	984	983	11,921
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,005	1,002	1,001	998	997	994	993	990	988	986	984	983	11,921

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	
3	Less: Accumulated Depreciation		(26,769)	(27,606)	(26,447)	(29,286)	(30,125)	(30,964)	(31,803)	(32,642)	(33,481)	(34,320)	(35,159)	(35,998)	(36,837)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		320,429	319,590	318,751	317,912	317,073	316,234	315,395	314,556	313,717	312,878	312,039	311,200	310,361	
6	Average Net Investment			320,009	319,170	318,331	317,492	316,653	315,814	314,975	314,136	313,297	312,458	311,619	310,780	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		787	785	783	781	779	777	775	773	771	769	767	765	9,312
	b. Equity Component Grossed Up For Taxes	8.02%		2,140	2,134	2,128	2,123	2,117	2,112	2,106	2,100	2,095	2,089	2,084	2,078	25,306
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.90%		839	839	839	839	839	839	839	839	839	839	839	839	10,068
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		293	293	293	293	293	293	293	293	293	293	293	293	3,516
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,059	4,051	4,043	4,036	4,028	4,021	4,013	4,005	3,998	3,990	3,983	3,975	48,202
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,059	4,051	4,043	4,036	4,028	4,021	4,013	4,005	3,998	3,990	3,983	3,975	48,202

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation		(36,347)	(39,134)	(39,921)	(40,708)	(41,495)	(42,282)	(43,069)	(43,858)	(44,643)	(45,430)	(46,217)	(47,004)	(47,791)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		311,237	310,450	309,663	308,876	308,089	307,302	306,515	305,728	304,941	304,154	303,367	302,580	301,793	
6	Average Net Investment			310,843	310,056	309,269	308,482	307,695	306,908	306,121	305,334	304,547	303,760	302,973	302,186	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		765	763	761	759	757	755	753	751	749	747	745	743	9,048
	b. Equity Component Grossed Up For Taxes	8.02%		2,078	2,073	2,068	2,063	2,057	2,052	2,047	2,042	2,036	2,031	2,026	2,020	24,593
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.70%		787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008990		262	262	262	262	262	262	262	262	262	262	262	262	3,144
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,892	3,885	3,878	3,871	3,863	3,856	3,849	3,842	3,834	3,827	3,820	3,812	46,229
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,892	3,885	3,878	3,871	3,863	3,856	3,849	3,842	3,834	3,827	3,820	3,812	46,229

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3	Less: Accumulated Depreciation		(10,983)	(11,117)	(11,251)	(11,385)	(11,519)	(11,653)	(11,787)	(11,921)	(12,055)	(12,189)	(12,323)	(12,457)	(12,591)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		123,029	122,895	122,761	122,627	122,493	122,359	122,225	122,091	121,957	121,823	121,689	121,555	121,421	
6	Average Net Investment			122,962	122,828	122,694	122,560	122,426	122,292	122,158	122,024	121,890	121,756	121,622	121,488	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		303	302	302	302	301	301	301	300	300	300	299	299	3,610
	b. Equity Component Grossed Up For Taxes	8.02%		822	821	820	819	819	818	817	816	815	814	813	812	9,806
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.20%		134	134	134	134	134	134	134	134	134	134	134	134	1,608
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.012430		139	139	139	139	139	139	139	139	139	139	139	139	1,668
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,398	1,396	1,395	1,394	1,393	1,392	1,391	1,389	1,388	1,387	1,385	1,384	16,692
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,398	1,396	1,395	1,394	1,393	1,392	1,391	1,389	1,388	1,387	1,385	1,384	16,692

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		381,560	381,560	381,560	381,560	381,560	361,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation		(25,734)	(26,147)	(26,560)	(26,973)	(27,386)	(27,799)	(28,212)	(28,625)	(29,038)	(29,451)	(29,864)	(30,277)	(30,690)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		355,826	355,413	355,000	354,587	354,174	353,761	353,348	352,935	352,522	352,109	351,696	351,283	350,870	
6	Average Net Investment			355,619	355,206	354,793	354,380	353,967	353,554	353,141	352,728	352,315	351,902	351,489	351,076	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		875	874	873	872	871	870	869	868	867	866	865	864	10,434
	b. Equity Component Grossed Up For Taxes	8.02%		2,378	2,375	2,372	2,369	2,367	2,364	2,361	2,358	2,356	2,353	2,350	2,347	28,350
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.30%		413	413	413	413	413	413	413	413	413	413	413	413	4,956
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008590		273	273	273	273	273	273	273	273	273	273	273	273	3,276
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,939	3,935	3,931	3,927	3,924	3,920	3,916	3,912	3,909	3,905	3,901	3,897	47,016
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,939	3,935	3,931	3,927	3,924	3,920	3,916	3,912	3,909	3,905	3,901	3,897	47,016

For Project: CAIR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			7,724	5,338	(501)	4,871	206,286	4,810	50,000	100,000	100,000	0	0	0	478,528
	b. Clearings to Plant			7,724	5,338	(501)	4,871	206,286	4,810	50,000	100,000	100,000	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		17,586,499	17,594,223	17,599,561	17,599,059	17,603,931	17,810,216	17,815,027	17,865,027	17,965,027	18,065,027	18,065,027	18,065,027	18,065,027	
3	Less: Accumulated Depreciation		(1,332,244)	(1,354,237)	(1,376,236)	(1,398,235)	(1,420,240)	(1,442,503)	(1,464,772)	(1,487,103)	(1,509,559)	(1,532,140)	(1,554,721)	(1,577,302)	(1,599,883)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		16,254,256	16,239,986	16,223,325	16,200,825	16,183,691	16,367,714	16,350,255	16,377,924	16,455,468	16,532,887	16,510,306	16,487,725	16,465,144	
6	Average Net Investment			16,247,121	16,231,656	16,212,075	16,192,258	16,275,703	16,358,985	16,364,090	16,416,696	16,494,178	16,521,597	16,499,016	16,476,435	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		39,973	39,935	39,887	39,838	40,043	40,248	40,261	40,390	40,581	40,648	40,593	40,537	482,934
	b. Equity Component Grossed Up For Taxes	8.02%		108,631	108,528	108,397	108,264	108,822	109,379	109,413	109,765	110,283	110,466	110,315	110,164	1,312,427
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.50%		21,993	21,999	21,999	22,005	22,263	22,269	22,331	22,456	22,581	22,581	22,581	22,581	267,639
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		11,554	11,557	11,557	11,560	11,695	11,699	11,731	11,797	11,863	11,863	11,863	11,863	140,602
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			182,151	182,019	181,840	181,667	182,823	183,595	183,736	184,408	185,308	185,558	185,352	185,145	2,203,602
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			182,151	182,019	181,840	181,667	182,823	183,595	183,736	184,408	185,308	185,558	185,352	185,145	2,203,602

For Project: CAIR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	
3	Less: Accumulated Depreciation		(856,397)	(882,177)	(907,957)	(933,737)	(959,517)	(985,297)	(1,011,077)	(1,036,857)	(1,062,637)	(1,088,417)	(1,114,197)	(1,139,977)	(1,165,757)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		11,517,986	11,492,206	11,466,426	11,440,646	11,414,866	11,389,086	11,363,306	11,337,526	11,311,746	11,285,966	11,260,186	11,234,406	11,208,626	
6	Average Net Investment			11,505,096	11,479,316	11,453,536	11,427,756	11,401,976	11,376,196	11,350,416	11,324,636	11,298,856	11,273,076	11,247,296	11,221,516	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		28,306	28,243	28,179	28,116	28,052	27,989	27,926	27,862	27,799	27,735	27,672	27,608	335,487
	b. Equity Component Grossed Up For Taxes	8.02%		76,925	76,753	76,580	76,408	76,236	76,063	75,891	75,719	75,546	75,374	75,201	75,029	911,725
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	309,360
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	97,512
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			139,137	138,902	138,665	138,430	138,194	137,958	137,723	137,487	137,251	137,015	136,779	136,543	1,654,084
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			139,137	138,902	138,665	138,430	138,194	137,958	137,723	137,487	137,251	137,015	136,779	136,543	1,654,084

For Project: CAIR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			6,992	1,034	747,728	585	0	675,758	0	0	0	0	193,074	85,884	1,711,055
	b. Clearings to Plant			6,529	1,034	71,970	585	0	(585)	0	0	0	0	0	1,823,101	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other							0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		94,739,383	94,745,911	94,746,945	94,818,916	94,819,500	94,819,500	94,818,916	94,818,916	94,818,916	94,818,916	94,818,916	94,818,916	96,642,017	
3	Less: Accumulated Depreciation		(6,117,379)	(6,312,398)	(6,507,419)	(6,702,588)	(6,897,758)	(7,092,928)	(7,288,097)	(7,483,266)	(7,678,435)	(7,873,604)	(8,068,773)	(8,263,942)	(8,460,987)	
4	CWIP - Non-Interest Bearing		191,579	192,042	192,042	867,800	867,800	867,800	1,544,143	1,544,143	1,544,143	1,544,143	1,544,143	1,737,217	0	
5	Net Investment (Lines 2 + 3 + 4)		88,813,583	88,625,556	88,431,569	88,984,128	88,789,543	88,594,373	89,074,962	88,879,793	88,684,624	88,489,455	88,294,286	88,292,191	88,181,030	
6	Average Net Investment			88,719,569	88,528,562	88,707,849	88,886,836	88,691,958	88,834,667	88,977,377	88,782,208	88,587,039	88,391,870	88,293,238	88,236,610	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		218,278	217,808	218,249	218,689	218,210	218,561	218,912	218,432	217,952	217,472	217,229	217,090	2,616,882
	b. Equity Component Grossed Up For Taxes	8.02%		593,195	591,918	593,117	594,313	593,010	593,965	594,919	593,614	592,309	591,004	590,345	589,966	7,111,675
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.47% (Note 1)		195,019	195,021	195,169	195,170	195,170	195,169	195,169	195,169	195,169	195,169	195,169	197,045	2,343,608
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		62,216	62,217	62,264	62,265	62,265	62,264	62,264	62,264	62,264	62,264	62,264	63,462	748,273
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,068,708	1,066,964	1,068,799	1,070,437	1,068,655	1,069,959	1,071,264	1,069,479	1,067,694	1,065,909	1,065,007	1,067,563	12,820,438
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,068,708	1,066,964	1,068,799	1,070,437	1,068,655	1,069,959	1,071,264	1,069,479	1,067,694	1,065,909	1,065,007	1,067,563	12,820,438

Note 1: The depreciation rate for project 7.4C is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result, the blended rate shown is based on approximately 98% of the investment in FERC account 312 at an approved depreciation rate of 2.50% and 2% of the investment in FERC account 315 at an approved depreciation rate of 1.0%.

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			38,225	20,699	17,826	310,035	232,678	107,046	182,822	93,822	350,400	8,400	8,400	57,782	1,428,135
	b. Clearings to Plant			12,216	20,351	16,249	6,231	0	0	0	875,805	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		625,142,472	625,154,687	625,175,038	625,191,288	625,197,518	625,197,518	625,197,518	625,197,518	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	
3	Less: Accumulated Depreciation		(32,011,109)	(33,115,549)	(34,220,025)	(35,324,530)	(36,429,046)	(37,533,562)	(38,632,868)	(39,732,174)	(40,832,250)	(41,933,096)	(43,033,942)	(44,134,788)	(45,235,634)	
4	CWIP - Non-Interest Bearing		22,468	48,477	48,824	50,402	354,206	586,884	693,931	876,752	94,769	445,169	453,569	461,969	519,751	
5	Net Investment (Lines 2 + 3 + 4)		593,153,830	592,087,615	591,003,838	589,917,159	589,122,679	588,250,841	587,258,581	586,342,097	585,335,843	584,585,397	583,492,951	582,400,505	581,357,441	
6	Average Net Investment			592,620,723	591,545,727	590,460,499	589,519,919	588,686,760	587,754,711	586,800,339	585,838,970	584,960,620	584,039,174	582,946,728	581,878,973	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,458,032	1,455,387	1,452,717	1,450,403	1,448,353	1,446,060	1,443,712	1,441,347	1,439,186	1,436,919	1,434,231	1,431,604	17,337,951
	b. Equity Component Grossed Up For Taxes	8.02%		3,962,369	3,955,182	3,947,926	3,941,637	3,936,066	3,929,834	3,923,453	3,917,025	3,911,153	3,904,992	3,897,687	3,890,548	47,117,872
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	(Note 1)		1,104,440	1,104,476	1,104,505	1,104,516	1,104,516	1,099,306	1,099,306	1,100,076	1,100,846	1,100,846	1,100,846	1,100,846	13,224,525
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		410,518	410,532	410,542	410,546	410,546	410,546	410,546	411,121	411,121	411,121	411,121	411,121	4,929,381
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			6,935,359	6,925,577	6,915,690	6,907,102	6,899,481	6,885,746	6,877,017	6,869,569	6,862,306	6,853,878	6,843,885	6,834,119	82,609,729
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			6,935,359	6,925,577	6,915,690	6,907,102	6,899,481	6,885,746	6,877,017	6,869,569	6,862,306	6,853,878	6,843,885	6,834,119	82,609,729

Note 1: The depreciation rate for project 7.4d is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result, the blended rate shown
Jan-May (at 2.12%) is based on approximately 70% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, approximately 15% of the investment in FERC account 311 at an approved depreciation rate of 1.5%, approximately 15% of the investment in FERC account 315 at an approved depreciation rate of 1.0%.
June-Dec (at 2.11%) is based on approximately 66% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, approximately 20% of the investment in FERC account 311 at an approved depreciation rate of 1.5%, approximately 12% of the investment in FERC account 315 at an approved depreciation rate of 1.0% and approximately 2% of the investment in FERC account 316 at an approved depreciation rate of 2.10%.

For Project: CAIR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	
3	Less: Accumulated Depreciation		(3,858,973)	(3,986,599)	(4,114,225)	(4,241,851)	(4,369,477)	(4,497,103)	(4,624,729)	(4,752,355)	(4,879,981)	(5,007,607)	(5,135,233)	(5,262,859)	(5,390,485)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		57,401,729	57,274,103	57,146,477	57,018,851	56,891,225	56,763,599	56,635,973	56,508,347	56,380,721	56,253,095	56,125,469	55,997,843	55,870,217	
6	Average Net Investment			57,337,916	57,210,290	57,082,664	56,955,038	56,827,412	56,699,786	56,572,160	56,444,534	56,316,908	56,189,282	56,061,656	55,934,030	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		141,069	140,755	140,441	140,127	139,813	139,499	139,185	138,871	138,557	138,243	137,929	137,615	1,672,104
	b. Equity Component Grossed Up For Taxes	8.02%		383,372	382,518	381,665	380,812	379,958	379,105	378,252	377,398	376,545	375,692	374,838	373,985	4,544,140
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	1,531,512
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	482,736
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			692,295	691,127	689,960	688,793	687,625	686,458	685,291	684,123	682,956	681,789	680,621	679,454	8,230,492
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			692,295	691,127	689,960	688,793	687,625	686,458	685,291	684,123	682,956	681,789	680,621	679,454	8,230,492

For Project: CAIR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			2,833	0	(125,004)	(56)	0	0	0	0	0	0	0	0	(122,228)
	b. Clearings to Plant			2,833	0	(125,004)	(56)	0	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		129,850,154	129,852,987	129,852,987	129,727,982	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	
3	Less: Accumulated Depreciation		(6,802,208)	(7,060,832)	(7,319,456)	(7,577,831)	(7,836,206)	(8,094,581)	(8,352,956)	(8,611,331)	(8,869,706)	(9,128,081)	(9,386,456)	(9,644,831)	(9,903,206)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		123,047,946	122,792,155	122,533,531	122,150,151	121,891,720	121,633,345	121,374,970	121,116,595	120,858,220	120,599,845	120,341,470	120,083,095	119,824,720	
6	Average Net Investment			122,920,050	122,662,843	122,341,841	122,020,936	121,762,533	121,504,158	121,245,783	120,987,408	120,729,033	120,470,658	120,212,283	119,953,908	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		302,422	301,789	300,999	300,210	299,574	298,938	298,303	297,667	297,031	296,395	295,760	295,124	3,584,212
	b. Equity Component Grossed Up For Taxes	8.02%		821,866	820,146	818,000	815,854	814,126	812,399	810,671	808,944	807,216	805,489	803,761	802,034	9,740,506
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.39% (Note 1)		258,624	258,624	258,375	258,375	258,375	258,375	258,375	258,375	258,375	258,375	258,375	258,375	3,100,998
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		85,270	85,270	85,188	85,188	85,188	85,188	85,188	85,188	85,188	85,188	85,188	85,188	1,022,420
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,468,182	1,465,829	1,462,562	1,459,627	1,457,263	1,454,900	1,452,537	1,450,174	1,447,810	1,445,447	1,443,084	1,440,721	17,448,136
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,468,182	1,465,829	1,462,562	1,459,627	1,457,263	1,454,900	1,452,537	1,450,174	1,447,810	1,445,447	1,443,084	1,440,721	17,448,136

Note 1: The depreciation rate for project 7.4F is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result, the blended rate shown is based on approximately 92.5% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, 7.5% of the investment in FERC account 315 at an approved depreciation rate of 1.0%.

For Project: CAIR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing Controls (Project 7.4g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	
3	Less: Accumulated Depreciation		(34,895)	(36,666)	(38,437)	(40,208)	(41,979)	(43,750)	(45,521)	(47,292)	(49,063)	(50,834)	(52,605)	(54,376)	(56,147)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		815,303	813,532	811,761	809,990	808,219	806,448	804,677	802,906	801,135	799,364	797,593	795,822	794,051	
6	Average Net Investment			814,417	812,646	810,875	809,104	807,333	805,562	803,791	802,020	800,249	798,478	796,707	794,936	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,004	1,999	1,995	1,991	1,986	1,982	1,978	1,973	1,969	1,965	1,960	1,956	23,758
	b. Equity Component Grossed Up For Taxes	8.02%		5,445	5,433	5,422	5,410	5,398	5,386	5,374	5,362	5,351	5,339	5,327	5,315	64,562
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	21,252
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		558	558	558	558	558	558	558	558	558	558	558	558	6,696
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,778	9,761	9,746	9,730	9,713	9,697	9,681	9,664	9,649	9,633	9,616	9,600	116,268
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			9,778	9,761	9,746	9,730	9,713	9,697	9,681	9,664	9,649	9,633	9,616	9,600	116,268

For Project: CAIR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing Controls (Project 7.4h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	
3	Less: Accumulated Depreciation		(33,339)	(35,250)	(37,161)	(39,072)	(40,983)	(42,894)	(44,805)	(46,716)	(48,627)	(50,538)	(52,449)	(54,360)	(56,271)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		884,059	882,148	880,237	878,326	876,415	874,504	872,593	870,682	868,771	866,860	864,949	863,038	861,127	
6	Average Net Investment			883,103	881,192	879,281	877,370	875,459	873,548	871,637	869,726	867,815	865,904	863,993	862,082	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,173	2,168	2,163	2,159	2,154	2,149	2,144	2,140	2,135	2,130	2,126	2,121	25,762
	b. Equity Component Grossed Up For Taxes	8.02%		5,905	5,892	5,879	5,866	5,853	5,841	5,828	5,815	5,802	5,790	5,777	5,764	70,012
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	22,932
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		602	602	602	602	602	602	602	602	602	602	602	602	7,224
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,591	10,573	10,555	10,538	10,520	10,503	10,485	10,468	10,450	10,433	10,416	10,398	125,930
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			10,591	10,573	10,555	10,538	10,520	10,503	10,485	10,468	10,450	10,433	10,416	10,398	125,930

For Project: CAIR Crystal River AFUDC - CR4 SCR (Project 7.4i)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			11,807	2,714	104,006	(11)	0	0	0	200,000	0	0	600,000	0	918,515
	b. Clearings to Plant			11,807	2,714	104,006	(11)	0	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		108,679,881	108,691,687	108,694,401	108,798,407	108,798,396	108,798,396	108,798,396	108,798,396	108,798,396	108,798,396	108,798,396	108,798,396	108,798,396	
3	Less: Accumulated Depreciation		(4,366,159)	(4,589,883)	(4,813,612)	(5,037,555)	(5,261,499)	(5,485,442)	(5,709,386)	(5,933,329)	(6,157,272)	(6,381,216)	(6,605,159)	(6,829,102)	(7,053,046)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	200,000	200,000	200,000	800,000	800,000	
5	Net Investment (Lines 2 + 3 + 4)		104,313,722	104,101,805	103,880,789	103,760,851	103,536,897	103,312,954	103,089,010	102,865,067	102,841,124	102,617,180	102,393,237	102,769,293	102,545,350	
6	Average Net Investment			104,207,763	103,991,297	103,820,820	103,648,874	103,424,925	103,200,982	102,977,039	102,853,095	102,729,152	102,505,209	102,581,265	102,657,322	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		256,384	255,851	255,432	255,009	254,458	253,907	253,356	253,051	252,746	252,195	252,382	252,569	3,047,340
	b. Equity Component Grossed Up For Taxes	8.02%		696,752	695,305	694,165	693,015	691,518	690,020	688,523	687,694	686,866	685,368	685,877	686,385	8,281,488
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.47% (Note 1)		223,724	223,729	223,943	223,943	223,943	223,943	223,943	223,943	223,943	223,943	223,943	223,943	2,686,887
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		71,374	71,376	71,444	71,444	71,444	71,444	71,444	71,444	71,444	71,444	71,444	71,444	857,190
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,248,234	1,246,261	1,244,984	1,243,411	1,241,363	1,239,314	1,237,266	1,236,132	1,234,999	1,232,950	1,233,646	1,234,341	14,872,905
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,248,234	1,246,261	1,244,984	1,243,411	1,241,363	1,239,314	1,237,266	1,236,132	1,234,999	1,232,950	1,233,646	1,234,341	14,872,905

Note 1: The depreciation rate for project 7.4i is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result, the blended rate shown is based on approximately 98% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, 2% of the investment in FERC account 315 at an approved depreciation rate of 1.0%.

For Project: CAIR Crystal River AFUDC - CR4 FGD (Project 7.4j)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			3,895	0	(5)	0	0	0	0	0	0	0	0	0	3,890
	b. Clearings to Plant			3,895	0	(5)	0	0	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		139,570,706	139,574,600	139,574,600	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	
3	Less: Accumulated Depreciation		(5,600,999)	(5,889,453)	(6,177,907)	(6,466,362)	(6,754,816)	(7,043,270)	(7,331,724)	(7,620,178)	(7,908,632)	(8,197,086)	(8,485,541)	(8,773,995)	(9,062,449)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		133,969,707	133,685,147	133,396,693	133,108,234	132,819,780	132,531,326	132,242,872	131,954,418	131,665,963	131,377,509	131,089,055	130,800,601	130,512,147	
6	Average Net Investment			133,827,427	133,540,920	133,252,464	132,964,007	132,675,553	132,387,099	132,098,645	131,810,190	131,521,736	131,233,282	130,944,828	130,656,374	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		329,257	328,552	327,843	327,133	326,423	325,714	325,004	324,294	323,585	322,875	322,165	321,456	3,904,301
	b. Equity Component Grossed Up For Taxes	8.02%		894,794	892,879	890,950	889,021	887,093	885,164	883,235	881,307	879,378	877,449	875,521	873,592	10,610,383
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.46% (Note 1)		288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	3,461,450
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	1,099,848
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,604,159	1,601,539	1,598,901	1,596,262	1,593,624	1,590,986	1,588,347	1,585,709	1,583,071	1,580,432	1,577,794	1,575,156	19,075,982
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,604,159	1,601,539	1,598,901	1,596,262	1,593,624	1,590,986	1,588,347	1,585,709	1,583,071	1,580,432	1,577,794	1,575,156	19,075,982

Note 1: The depreciation rate for project 7.4j is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result, the blended rate shown is based on approximately 98.75% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, 1.10% of the investment in FERC account 315 at an approved depreciation rate of 1.0% and 0.15% of the investment in FERC account 311 at an approved depreciation rate of 1.50%.

For Project: CAIR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	
3	Less: Accumulated Depreciation		(1,074,830)	(1,118,555)	(1,162,280)	(1,206,005)	(1,249,730)	(1,293,455)	(1,337,180)	(1,380,905)	(1,424,630)	(1,468,355)	(1,512,080)	(1,555,805)	(1,599,530)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		19,913,366	19,869,641	19,825,916	19,782,191	19,738,466	19,694,741	19,651,016	19,607,291	19,563,566	19,519,841	19,476,116	19,432,391	19,388,666	
6	Average Net Investment			19,891,504	19,847,779	19,804,054	19,760,329	19,716,604	19,672,879	19,629,154	19,585,429	19,541,704	19,497,979	19,454,254	19,410,529	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		48,939	48,832	48,724	48,617	48,509	48,401	48,294	48,186	48,079	47,971	47,864	47,756	580,172
	b. Equity Component Grossed Up For Taxes	8.02%		132,998	132,706	132,413	132,121	131,829	131,536	131,244	130,952	130,659	130,367	130,075	129,782	1,576,682
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	524,700
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	165,384
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			239,444	239,045	238,644	238,245	237,845	237,444	237,045	236,645	236,245	235,845	235,446	235,045	2,846,938
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			239,444	239,045	238,644	238,245	237,845	237,444	237,045	236,645	236,245	235,845	235,446	235,045	2,846,938

For Project: CAIR Crystal River AFUDC - CR5 Acid Mist Mitigation Controls (Project 7.4l)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	
3	Less: Accumulated Depreciation		(382,090)	(401,687)	(421,284)	(440,881)	(460,478)	(480,075)	(499,672)	(519,269)	(538,866)	(558,463)	(578,060)	(597,657)	(617,254)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		9,024,615	9,005,018	8,985,421	8,965,824	8,946,227	8,926,630	8,907,033	8,887,436	8,867,839	8,848,242	8,828,645	8,809,048	8,789,451	
6	Average Net Investment			9,014,817	8,995,220	8,975,623	8,956,026	8,936,429	8,916,832	8,897,235	8,877,638	8,858,041	8,838,444	8,818,847	8,799,250	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		22,179	22,131	22,083	22,035	21,986	21,938	21,890	21,842	21,794	21,745	21,697	21,649	262,969
	b. Equity Component Grossed Up For Taxes	8.02%		60,275	60,144	60,013	59,882	59,751	59,620	59,489	59,357	59,226	59,095	58,964	58,833	714,849
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	235,164
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	74,124
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			108,228	108,049	107,870	107,691	107,511	107,332	107,153	106,973	106,794	106,614	106,435	106,256	1,286,906
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			108,228	108,049	107,870	107,691	107,511	107,332	107,153	106,973	106,794	106,614	106,435	106,256	1,286,906

For Project: CAIR Crystal River AFUDC - FGD Settling Pond (Project 7.4m)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	
3	Less: Accumulated Depreciation		(200,760)	(210,357)	(219,954)	(229,551)	(239,148)	(248,745)	(258,342)	(267,939)	(277,536)	(287,133)	(296,730)	(306,327)	(315,924)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		7,476,556	7,466,959	7,457,362	7,447,765	7,438,168	7,428,571	7,418,974	7,409,377	7,399,780	7,390,183	7,380,586	7,370,989	7,361,392	
6	Average Net Investment			7,471,757	7,462,160	7,452,563	7,442,966	7,433,369	7,423,772	7,414,175	7,404,578	7,394,981	7,385,384	7,375,787	7,366,190	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		18,383	18,359	18,336	18,312	18,288	18,265	18,241	18,218	18,194	18,170	18,147	18,123	219,036
	b. Equity Component Grossed Up For Taxes	8.02%		49,958	49,893	49,829	49,765	49,701	49,637	49,573	49,508	49,444	49,380	49,316	49,252	595,256
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.50%		9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	115,164
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	60,492
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			82,979	82,890	82,803	82,715	82,627	82,540	82,452	82,364	82,276	82,188	82,101	82,013	989,948
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			82,979	82,890	82,803	82,715	82,627	82,540	82,452	82,364	82,276	82,188	82,101	82,013	989,948

For Project: CAIR Crystal River AFUDC - Coal Pile Runoff Treatment System (Project 7.4n)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	
3	Less: Accumulated Depreciation		(449,036)	(468,997)	(488,958)	(508,919)	(528,880)	(548,841)	(568,802)	(588,763)	(608,724)	(628,685)	(646,646)	(668,607)	(688,568)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		15,520,070	15,500,109	15,480,148	15,460,187	15,440,226	15,420,265	15,400,304	15,380,343	15,360,382	15,340,421	15,320,460	15,300,499	15,280,538	
6	Average Net Investment			15,510,090	15,490,129	15,470,168	15,450,207	15,430,246	15,410,285	15,390,324	15,370,363	15,350,402	15,330,441	15,310,480	15,290,519	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		38,160	38,111	38,061	38,012	37,963	37,914	37,865	37,816	37,767	37,718	37,669	37,619	454,675
	b. Equity Component Grossed Up For Taxes	8.02%		103,703	103,570	103,436	103,303	103,169	103,036	102,902	102,769	102,636	102,502	102,369	102,235	1,235,630
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.50%		19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	239,532
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	125,832
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			172,310	172,128	171,944	171,762	171,579	171,397	171,214	171,032	170,850	170,667	170,485	170,301	2,055,669
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			172,310	172,128	171,944	171,762	171,579	171,397	171,214	171,032	170,850	170,667	170,485	170,301	2,055,669

For Project: CAIR Crystal River AFUDC - Dibasic Acid Additive System (Project 7.4o)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	
3	Less: Accumulated Depreciation		(36,112)	(38,392)	(40,672)	(42,952)	(45,232)	(47,512)	(49,792)	(52,072)	(54,352)	(56,632)	(58,912)	(61,192)	(63,472)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,058,307	1,056,027	1,053,747	1,051,467	1,049,187	1,046,907	1,044,627	1,042,347	1,040,067	1,037,787	1,035,507	1,033,227	1,030,947	
6	Average Net Investment			1,057,167	1,054,887	1,052,607	1,050,327	1,048,047	1,045,767	1,043,487	1,041,207	1,038,927	1,036,647	1,034,367	1,032,087	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,601	2,595	2,590	2,584	2,579	2,573	2,567	2,562	2,556	2,550	2,545	2,539	30,841
	b. Equity Component Grossed Up For Taxes	8.02%		7,068	7,053	7,038	7,023	7,007	6,992	6,977	6,962	6,946	6,931	6,916	6,901	83,814
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	27,360
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		719	719	719	719	719	719	719	719	719	719	719	719	8,628
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			12,668	12,647	12,627	12,606	12,585	12,564	12,543	12,523	12,501	12,480	12,460	12,439	150,643
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			12,668	12,647	12,627	12,606	12,585	12,564	12,543	12,523	12,501	12,480	12,460	12,439	150,643

For Project: CAIR Crystal River AFUDC - Bottom Ash (PH)/Fly Ash (Ammonia) (Project 7.4p)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			24,993	236	2,054	246,996	1,369,209	1,564,224	2,970,375	5,504,000	1,340,000	2,395,991	1,842,970	863,040	18,124,086
	b. Clearings to Plant			24,993	236	2,054	2,596	951,585	0	(54,000)	0	0	0	0	17,196,624	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		117,152	142,145	142,381	144,434	147,030	1,098,615	1,098,615	1,044,615	1,044,615	1,044,615	1,044,615	1,044,615	18,241,238	
3	Less: Accumulated Depreciation		(686)	(935)	(1,184)	(1,437)	(1,694)	(3,617)	(5,540)	(7,368)	(9,196)	(11,024)	(12,852)	(14,680)	(31,555)	
4	CWIP - Non-Interest Bearing		0	0	0	0	244,400	662,024	2,226,248	5,250,623	10,754,623	12,094,623	14,490,614	16,333,584	0	
5	Net Investment (Lines 2 + 3 + 4)		116,466	141,210	141,197	142,998	389,737	1,757,023	3,319,323	6,287,870	11,790,042	13,128,214	15,522,377	17,363,519	18,209,684	
6	Average Net Investment			128,838	141,204	142,098	266,367	1,073,380	2,538,173	4,803,596	9,038,956	12,459,128	14,325,295	16,442,948	17,786,601	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		317	347	350	655	2,641	6,245	11,818	22,239	30,653	35,245	40,455	43,761	194,726
	b. Equity Component Grossed Up For Taxes	8.02%		861	944	950	1,781	7,177	16,971	32,118	60,436	83,304	95,782	109,941	118,924	529,189
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.10%		249	249	253	257	1,923	1,923	1,828	1,828	1,828	1,828	1,828	16,875	30,869
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		93	93	95	97	721	721	686	686	686	686	686	11,978	17,226
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,520	1,633	1,648	2,790	12,462	25,860	46,450	85,189	116,471	133,541	152,910	191,538	772,012
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,520	1,633	1,648	2,790	12,462	25,860	46,450	85,189	116,471	133,541	152,910	191,538	772,012

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes	8.02%		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
8	Investment Expenses															
	a. Depreciation	2.50%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009280		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Estimated Jul-12	Estimated Aug-12	Estimated Sep-12	Estimated Oct-12	Estimated Nov-12	Estimated Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation		(14,722)	(15,234)	(15,746)	(16,258)	(16,770)	(17,282)	(17,794)	(18,306)	(18,818)	(19,330)	(19,842)	(20,354)	(20,866)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		347,014	346,502	345,990	345,478	344,966	344,454	343,942	343,430	342,918	342,406	341,894	341,382	340,870	
6	Average Net Investment			346,758	346,246	345,734	345,222	344,710	344,198	343,686	343,174	342,662	342,150	341,638	341,126	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		853	852	851	849	848	847	846	844	843	842	841	839	10,155
	b. Equity Component Grossed Up For Taxes	8.02%		2,318	2,315	2,312	2,308	2,305	2,301	2,298	2,295	2,291	2,288	2,284	2,281	27,596
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.70%		512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009280		280	280	280	280	280	280	280	280	280	280	280	280	3,360
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,963	3,959	3,955	3,949	3,945	3,940	3,936	3,931	3,926	3,922	3,917	3,912	47,255
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,963	3,959	3,955	3,949	3,945	3,940	3,936	3,931	3,926	3,922	3,917	3,912	47,255

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	120007-EI	EXHIBIT	30
PARTY	Progress Energy Florida		
DESCRIPTION	Thomas Foster (TGF-3R) PSC Forms 42-1P		
DATE	through 42-8P January 2013 - Dec. 2013		

Witness: T.G. Foster
Exhibit __ (TGF-3)

Progress Energy Florida, Inc.
Environmental Cost Recovery
Commission Forms 42-1P Through 42-8P

January 2013 - December 2013
Calculation for the Projected Period Amount
January through December 2013

DOCKET NO. 120007-EI

DOCUMENT NUMBER-DATE
07086 OCT 17 12
FPSC-COMMISSION CLERK

Docket No. 120007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-3R)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered
For the Projected Period
JANUARY 2013 - DECEMBER 2013
(in Dollars)

Form 42-1P - REVISED 10/18/12

Line		Energy ($)	Transmission Demand ($)	Distribution Demand ($)	Production Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period					
	a Projected O&M Activities (Form 42-2P, Lines 7 through 9)	$ 30,123,995	$ 931,596	$ 1,204,461	$ 459,923	$ 32,719,975
	b Projected Capital Projects (Form 42-3P, Lines 7 through 9)	160,217,975	0	1,565	2,426,138	162,645,678
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	190,341,970	931,596	1,206,026	2,886,061	195,365,653
2	True-up for Estimated Over/(Under) Recovery for the current period January 2012 - December 2012 (Form 42-2E, Line 5 + 6 + 10)	15,911,372	(1,468,949)	681,587	(491,037)	14,632,974
3	Final True-up for the period January 2011 - December 2011 (Form 42-1A, Line 3)	(1,547,647)	1,392,796	(187,845)	(1,345,855)	(1,688,551)
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2013 - December 2013 (Line 1 - Line 2 - Line 3)	175,978,244	1,007,749	712,284	4,722,952	182,421,230
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$ 176,104,949	$ 1,008,475	$ 712,797	$ 4,726,353	$ 182,552,573

Docket No. 120007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-3R)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Form 42-2P

O&M Activities
(in Dollars)

	Description	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
	Description of O&M Activities													
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$110,583	$110,583	$110,583	$110,583	$110,583	$110,583	$110,583	$110,583	$110,583	$110,583	$110,583	$110,583	$1,326,996
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	$85,056	$85,056	$85,056	$85,056	$85,056	$85,056	$85,056	$85,056	$85,056	$85,056	$85,056	$85,056	1,020,672
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	0	0	0	0	12,000	174,600	0	0	186,600
3	Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	41,500	79,000	79,000	41,500	41,500	61,500	41,500	41,500	41,500	41,500	41,500	41,500	593,000
4	Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
5	SO2/NOx Emissions Allowances	213,484	173,434	175,397	205,724	291,898	307,538	351,617	396,578	298,123	249,871	114,536	144,947	2,923,146
6	Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
6a	Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	0	36,500	31,600	0	0	0	0	0	0	0	0	0	68,100
7.4	CAIR/CAMR Crystal River - Base	1,280,925	1,168,890	2,088,339	2,163,238	1,432,107	1,535,080	1,342,407	1,494,017	1,116,163	1,199,782	1,147,797	1,057,454	17,026,199
7.4	CAIR/CAMR Crystal River - Energy	609,747	841,019	768,761	776,364	907,208	969,352	950,457	984,941	956,723	955,276	855,588	1,122,056	10,697,492
7.4	CAIR/CAMR Crystal River - A&G	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	184,271
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	16,000	0	0	0	0	0	0	0	0	0	16,000
8	Arsenic Groundwater Standard - Base	0	0	10,000	0	0	7,500	0	7,500	0	6,000	0	0	31,000
9	Sea Turtle - Coastal Street Lighting - Distrib	208	208	208	208	208	208	208	208	208	208	208	208	2,500
11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
16	National Pollutant Discharge Elimination System - Energy	20,000	29,310	89,000	48,290	33,000	77,000	27,000	36,310	27,000	36,290	27,000	27,000	477,200
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
17.1	Mercury & Air Toxic Standards (MATS) Anclote - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total of O&M Activities	2,376,860	2,539,356	3,469,300	3,446,320	2,916,916	3,169,173	2,924,183	3,172,049	2,662,712	2,874,522	2,397,624	2,604,161	34,553,176
	Recoverable Costs Allocated to Energy	843,231	1,043,763	1,049,158	1,030,378	1,232,107	1,353,890	1,329,073	1,417,829	1,281,846	1,241,436	997,123	1,294,003	14,113,838
	Recoverable Costs Allocated to Demand - Transm	110,583	110,583	110,583	110,583	110,583	110,583	110,583	110,583	110,583	110,583	110,583	110,583	1,326,996
	Recoverable Costs Allocated to Demand - Distrib	85,264	85,264	85,264	85,264	85,264	85,264	85,264	85,264	97,264	259,864	85,264	85,264	1,209,772
	Recoverable Costs Allocated to Demand - Prod-Base	1,280,925	1,168,890	2,098,339	2,163,238	1,432,107	1,542,580	1,342,407	1,501,517	1,116,163	1,205,782	1,147,797	1,057,454	17,057,199
	Recoverable Costs Allocated to Demand - Prod-Intm	41,500	79,000	79,000	41,500	41,500	61,500	41,500	41,500	41,500	41,500	41,500	41,500	593,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	36,500	31,600	0	0	0	0	0	0	0	0	0	68,100
	Recoverable Costs Allocated to Demand - A&G	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	15,356	184,271
	Retail Energy Jurisdictional Factor	0.99450	0.99640	0.99770	0.99810	0.99800	0.99790	0.99710	0.99680	0.99670	0.99660	0.99680	0.99720	
	Retail Transmission Demand Jurisdictional Factor	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	
	Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
	Retail Production Demand Jurisdictional Factor - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
	Retail Production Demand Jurisdictional Factor - Intm	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
	Retail Production Demand Jurisdictional Factor - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
	Retail Production Demand Jurisdictional Factor - A&G	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	
	Jurisdictional Energy Recoverable Costs (A)	838,593	1,040,006	1,046,745	1,028,420	1,229,642	1,351,047	1,325,219	1,413,292	1,277,615	1,237,215	993,933	1,290,380	14,072,107
	Jurisdictional Demand Recoverable Costs - Transm (B)	77,633	77,633	77,633	77,633	77,633	77,633	77,633	77,633	77,633	77,633	77,633	77,633	931,596
	Jurisdictional Demand Recoverable Costs - Distrib (B)	84,890	84,890	84,890	84,890	84,890	84,890	84,890	84,890	96,837	258,724	84,890	84,890	1,204,461
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	1,189,787	1,085,723	1,949,042	2,009,324	1,330,212	1,432,825	1,246,894	1,394,684	1,036,748	1,119,991	1,066,131	982,216	15,843,577
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	30,172	57,435	57,435	30,172	30,172	44,712	30,172	30,172	30,172	30,172	30,172	30,172	431,130
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	35,012	30,312	0	0	0	0	0	0	0	0	0	65,324
	Jurisdictional Demand Recoverable Costs - A&G (B)	14,315	14,315	14,315	14,315	14,315	14,315	14,315	14,315	14,315	14,315	14,315	14,315	171,780
	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$2,235,390	$2,395,014	$3,260,372	$3,244,754	$2,766,864	$3,005,422	$2,779,123	$3,014,986	$2,533,320	$2,738,050	$2,267,074	$2,479,606	$32,719,975

s:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

Docket No. 12007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-3R)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Capital Investment Projects-Recoverable Costs
(in Dollars)

	Description	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Description of Investment Projects (A)														
1.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$ 35,709	$ 35,640	$ 35,570	$ 35,501	$ 35,431	$ 35,361	$ 35,292	$ 35,223	$ 35,153	$ 35,084	$ 35,014	$ 34,944	$ 423,922
1.1	Above Ground Tank Secondary Containment - Peaking	126,294	126,009	125,726	125,442	125,158	124,875	124,591	124,307	124,024	123,740	123,456	123,172	1,496,794
1.2	Above Ground Tank Secondary Containment - Base	30,123	30,072	30,021	29,969	29,917	29,865	29,814	29,762	29,710	29,659	29,607	29,555	358,074
1.3	Above Ground Tank Secondary Containment - Intermediate	2,859	2,854	2,850	2,845	2,840	2,836	2,831	2,827	2,822	2,818	2,813	2,809	34,004
5	SO2/NOX Emissions Allowances - Energy	182,055	180,401	178,910	177,281	175,154	172,592	169,775	166,577	163,608	161,265	159,707	158,598	2,045,923
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR CT's - Peaking	19,804	19,774	19,744	19,714	19,683	19,653	19,623	19,593	19,562	19,532	19,502	19,471	235,655
7.3	CAMR Crystal River - Base	2,472	2,472	2,472	2,472	2,472	2,472	2,472	2,472	2,472	2,472	2,472	2,472	29,664
7.4	CAIR/CAMR Crystal River AFUDC - Base (D)	13,885,065	13,948,000	13,937,034	13,921,598	13,902,330	13,883,061	13,864,008	13,845,168	13,826,327	13,807,487	13,788,647	13,769,627	166,378,352
7.4	CAIR/CAMR Crystal River AFUDC - Energy	7,363	7,255	7,255	7,255	7,255	7,255	7,255	7,255	7,255	7,255	7,255	7,255	87,169
9	Sea Turtle - Coastal Street Lighting -Distribution	122	124	126	127	129	130	131	134	135	137	138	139	1,572
10.1	Underground Storage Tanks - Base	1,638	1,637	1,634	1,632	1,629	1,626	1,624	1,621	1,619	1,616	1,613	1,611	19,500
10.2	Underground Storage Tanks - Intermediate	792	791	789	787	785	784	781	780	779	776	775	773	9,392
11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
11.1	Crystal River Thermal Discharge Compliance Project - Base	3,703	3,699	3,695	3,690	3,686	3,682	3,677	3,673	3,669	3,665	3,660	3,656	44,155
16	National Pollutant Discharge Elimination System (NPDES) - Intermediate	29,023	29,829	29,985	29,927	29,868	29,810	29,752	29,693	29,635	29,577	29,518	29,460	356,073
17	MATS - Crystal River 4 & 5 - Energy	10,779	10,950	11,121	11,505	12,104	14,540	29,500	50,871	65,831	78,654	89,767	95,323	480,945
17.1	MATS - Anclote Conversion - Energy	0	0	0	0	0	213,352	401,291	400,722	400,153	399,584	399,016	612,180	2,826,298
Total Investment Projects - Recoverable Costs		$ 14,337,801	$ 14,399,507	$ 14,386,932	$ 14,369,745	$ 14,348,441	$ 14,541,894	$ 14,722,416	$ 14,720,678	$ 14,712,754	$ 14,703,321	$ 14,692,960	$ 14,891,045	$ 174,827,493
Recoverable Costs Allocated to Energy		200,197	198,606	197,286	196,041	194,513	407,739	607,821	625,425	636,847	646,759	655,745	873,356	5,440,335
Recoverable Costs Allocated to Distribution Demand		122	124	126	127	129	130	131	134	135	137	138	139	1,572
Recoverable Costs Allocated to Demand - Production - Base		13,923,001	13,985,880	13,974,856	13,959,361	13,940,034	13,920,706	13,901,595	13,882,696	13,863,797	13,844,899	13,825,999	13,806,921	166,829,745
Recoverable Costs Allocated to Demand - Production - Intermediate		68,383	69,114	69,194	69,060	68,924	68,791	68,656	68,523	68,389	68,255	68,120	67,986	823,391
Recoverable Costs Allocated to Demand - Production - Peaking		146,098	145,783	145,470	145,156	144,841	144,528	144,214	143,900	143,586	143,272	142,958	142,643	1,732,449
Retail Energy Jurisdictional Factor		0.99450	0.99640	0.99770	0.99810	0.99800	0.99790	0.99710	0.99680	0.99670	0.99660	0.99680	0.99720	
Retail Distribution Demand Jurisdictional Factor		0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
Retail Demand Jurisdictional Factor - Production - Base		0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
Retail Demand Jurisdictional Factor - Production - Intermediate		0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
Retail Demand Jurisdictional Factor - Production - Peaking		0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
Jurisdictional Energy Recoverable Costs (B)		199,096	197,891	196,832	195,669	194,124	406,883	606,058	623,424	634,746	644,560	653,646	870,911	5,423,839
Jurisdictional Demand Recoverable Costs - Distribution (B)		121	123	125	126	128	129	130	133	134	136	137	138	1,565
Jurisdictional Demand Recoverable Costs - Production - Base (C)		12,932,379	12,990,785	12,980,545	12,966,152	12,948,201	12,930,248	12,912,497	12,894,942	12,877,388	12,859,834	12,842,279	12,824,559	154,959,809
Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)		49,716	50,248	50,306	50,208	50,110	50,013	49,915	49,818	49,721	49,623	49,525	49,428	598,630
Jurisdictional Demand Recoverable Costs - Production - Peaking (C)		140,143	139,841	139,541	139,239	138,937	138,637	138,336	138,035	137,733	137,432	137,131	136,829	1,661,834
Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$ 13,321,457	$ 13,378,888	$ 13,367,349	$ 13,351,395	$ 13,331,500	$ 13,525,910	$ 13,706,936	$ 13,706,352	$ 13,699,722	$ 13,691,586	$ 13,682,719	$ 13,881,864	$ 162,645,678

(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9; Form 42-8E, Line 5 for Projects 5 - Allowances and Project 7. 4 - Reagents
(B) Line 3 x Line 5
(C) Line 4 x Line 6
(D) January amount differs from the Form 42 4P p9 balance due to a $79,548 credit to reflect a correction to the depreciation expense for CAIR projects 7.4e and 7.4k in the 2012 Estimated / Actual filing.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(in Dollars)

Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant			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	
d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
Plant-in-Service/Depreciation Base		3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	3,719,068	
Less: Accumulated Depreciation		(848,871)	(856,999)	(865,127)	(873,255)	(881,383)	(889,511)	(897,639)	(905,767)	(913,895)	(922,023)	(930,151)	(938,279)	(946,407)	
CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
Net Investment (Lines 2 + 3 + 4)		$2,870,197	$2,862,069	$2,853,941	$2,845,813	$2,837,685	$2,829,557	$2,821,429	$2,813,301	$2,805,173	$2,797,045	$2,788,917	$2,780,789	$2,772,661	
Average Net Investment			$2,866,133	$2,858,005	$2,849,877	$2,841,749	$2,833,621	$2,825,493	$2,817,365	$2,809,237	$2,801,109	$2,792,981	$2,784,853	$2,776,725	
Return on Average Net Investment (B)															
a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		5,876	5,859	5,842	5,826	5,809	5,792	5,776	5,759	5,742	5,726	5,709	5,692	69,408
b. Equity Component Grossed Up For Taxes	7.80%		18,625	18,573	18,520	18,467	18,414	18,361	18,308	18,256	18,203	18,150	18,097	18,044	220,018
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Investment Expenses															
a. Depreciation (C)			8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	8,128	97,536
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	0
d. Property Taxes (D)			3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	36,960
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Total System Recoverable Expenses (Lines 7 + 8)			$35,709	$35,640	$35,570	$35,501	$35,431	$35,361	$35,292	$35,223	$35,153	$35,084	$35,014	$34,944	423,922
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$35,709	$35,640	$35,570	$35,501	$35,431	$35,361	$35,292	$35,223	$35,153	$35,084	$35,014	$34,944	423,922
Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Demand-Related Recoverable Costs (F)			25,962	25,911	25,860	25,810	25,759	25,709	25,658	25,608	25,557	25,507	25,456	25,405	308,204
Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$25,962	$25,911	$25,860	$25,810	$25,759	$25,709	$25,658	$25,608	$25,557	$25,507	$25,456	$25,405	$308,204

es:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - PEAKING (Project 4.1)
(in Dollars)

e Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
Plant-in-Service/Depreciation Base		11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	11,301,803	
Less: Accumulated Depreciation		(1,609,334)	(1,642,525)	(1,675,716)	(1,708,907)	(1,742,098)	(1,775,289)	(1,808,480)	(1,841,671)	(1,874,862)	(1,908,053)	(1,941,244)	(1,974,435)	(2,007,626)	
CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Net Investment (Lines 2 + 3 + 4)		$9,692,469	$9,659,278	$9,626,087	$9,592,896	$9,559,705	$9,526,514	$9,493,323	$9,460,132	$9,426,941	$9,393,750	$9,360,559	$9,327,368	$9,294,177	
Average Net Investment			$9,675,873	$9,642,682	$9,609,491	$9,576,300	$9,543,109	$9,509,918	$9,476,727	$9,443,536	$9,410,345	$9,377,154	$9,343,963	9,310,772	
Return on Average Net Investment (B)															
a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		19,836	19,767	19,699	19,631	19,563	19,495	19,427	19,359	19,291	19,223	19,155	19,087	233,533
b. Equity Component Grossed Up For Taxes	7.80%		62,878	62,662	62,447	62,231	62,015	61,800	61,584	61,368	61,153	60,937	60,721	60,505	740,301
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Investment Expenses															
a. Depreciation (C)			33,191	33,191	33,191	33,191	33,191	33,191	33,191	33,191	33,191	33,191	33,191	33,191	398,292
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	0
d. Property Taxes (D)			10,389	10,389	10,389	10,389	10,389	10,389	10,389	10,389	10,389	10,389	10,389	10,389	124,668
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Total System Recoverable Expenses (Lines 7 + 8)			$126,294	$126,009	$125,726	$125,442	$125,158	$124,875	$124,591	$124,307	$124,024	$123,740	$123,456	$123,172	1,496,794
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$126,294	$126,009	$125,726	$125,442	$125,158	$124,875	$124,591	$124,307	$124,024	$123,740	$123,456	$123,172	1,496,794
Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Demand Jurisdictional Factor - Production (Peaking)			0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Demand-Related Recoverable Costs (F)			121,146	120,873	120,601	120,329	120,057	119,785	119,513	119,240	118,969	118,696	118,424	118,152	1,435,785
Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$121,146	$120,873	$120,601	$120,329	$120,057	$119,785	$119,513	$119,240	$118,969	$118,696	$118,424	$118,152	$1,435,785

otes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

e	Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
	Plant-in-Service/Depreciation Base		2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	
	Less: Accumulated Depreciation		(288,410)	(294,456)	(300,502)	(306,548)	(312,594)	(318,640)	(324,686)	(330,732)	(336,778)	(342,824)	(348,870)	(354,916)	(360,962)	
	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
	Net Investment (Lines 2+ 3 + 4)		$2,597,861	$2,591,815	$2,585,769	$2,579,723	$2,573,677	$2,567,631	$2,561,585	$2,555,539	$2,549,493	$2,543,447	$2,537,401	$2,531,355	$2,525,309	
	Average Net Investment			$2,594,838	$2,588,792	$2,582,746	$2,576,700	$2,570,654	$2,564,608	$2,558,562	$2,552,516	$2,546,470	$2,540,424	$2,534,378	$2,528,332	
	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		5,319	5,307	5,295	5,282	5,270	5,257	5,245	5,233	5,220	5,208	5,195	5,183	63,014
	b. Equity Component Grossed Up For Taxes (B)	7.80%		16,862	16,823	16,784	16,745	16,705	16,666	16,627	16,587	16,548	16,509	16,470	16,430	199,756
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Investment Expenses															
	a. Depreciation (C)			6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	72,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	22,752
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Total System Recoverable Expenses (Lines 7 + 8)			$30,123	$30,072	$30,021	$29,969	$29,917	$29,865	$29,814	$29,762	$29,710	$29,659	$29,607	$29,555	358,074
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$30,123	$30,072	$30,021	$29,969	$29,917	$29,865	$29,814	$29,762	$29,710	$29,659	$29,607	$29,555	358,074
	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
	Retail Demand-Related Recoverable Costs (F)			27,980	27,932	27,885	27,837	27,788	27,740	27,693	27,644	27,596	27,549	27,500	27,452	332,597
	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$27,980	$27,932	$27,885	$27,837	$27,788	$27,740	$27,693	$27,644	$27,596	$27,549	$27,500	$27,452	$332,597

otes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant			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	
d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
Plant-in-Service/Depreciation Base		290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
Less: Accumulated Depreciation		(41,370)	(41,902)	(42,434)	(42,966)	(43,498)	(44,030)	(44,562)	(45,094)	(45,626)	(46,158)	(46,690)	(47,222)	(47,754)	
CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
Net Investment (Lines 2+ 3 + 4)		$248,928	$248,396	$247,864	$247,332	$246,800	$246,268	$245,736	$245,204	$244,672	$244,140	$243,608	$243,076	$242,544	
Average Net Investment			$248,662	$248,130	$247,598	$247,066	$246,534	$246,002	$245,470	$244,938	$244,406	$243,874	$243,342	$242,810	
Return on Average Net Investment (B)															
a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		510	509	508	506	505	504	503	502	501	500	499	498	6,045
b. Equity Component Grossed Up For Taxes	7.80%		1,616	1,612	1,609	1,606	1,602	1,599	1,595	1,592	1,588	1,585	1,581	1,578	19,163
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Investment Expenses															
a. Depreciation (C)			532	532	532	532	532	532	532	532	532	532	532	532	6,384
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (D)			201	201	201	201	201	201	201	201	201	201	201	201	2,412
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Total System Recoverable Expenses (Lines 7 + 8)			$2,859	$2,854	$2,850	$2,845	$2,840	$2,836	$2,831	$2,827	$2,822	$2,818	$2,813	$2,809	34,004
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$2,859	$2,854	$2,850	$2,845	$2,840	$2,836	$2,831	$2,827	$2,822	$2,818	$2,813	$2,809	34,004
Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Demand-Related Recoverable Costs (F)			2,079	2,075	2,072	2,068	2,065	2,062	2,058	2,055	2,052	2,049	2,045	2,042	24,722
Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,079	$2,075	$2,072	$2,068	$2,065	$2,062	$2,058	$2,055	$2,052	$2,049	$2,045	$2,042	$24,722

otes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Schedule of Amortization and Return
DEFERRED GAIN ON SALES OF EMISSION ALLLOWANCES (Project 5)
(in Dollars)

e Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Working Capital Dr (Cr)															
a. 1581001 SO_2 Emission Allowance Inventory		4,487,131	$4,462,278	$4,441,345	$4,420,648	$4,390,289	$4,353,741	$4,319,774	$4,282,556	$4,243,568	$4,215,641	$4,192,007	$4,184,006	$4,173,869	$4,173,869
b. 25401FL Auctioned SO_2 Allowance		(1,043,366)	(1,003,903)	(964,440)	(924,978)	(885,131)	(845,572)	(806,013)	(766,455)	(726,896)	(687,337)	(647,778)	(608,220)	(568,661)	($568,661)
c. 1581002 NOx Emission Allowance Inventory		17,959,819	17,731,725	17,539,762	17,345,599	17,130,387	16,835,478	16,522,349	16,168,391	15,771,243	15,461,487	15,195,692	15,049,599	14,875,230	14,875,230
d. Other															0
Total Working Capital		$21,403,584	$21,190,100	$21,016,666	$20,841,269	$20,635,545	$20,343,647	$20,036,109	$19,684,493	$19,287,914	$18,989,791	$18,739,921	$18,625,385	$18,480,438	$18,480,438
Average Net Investment			$21,296,842	$21,103,383	$20,928,968	$20,738,407	$20,489,596	$20,189,878	$19,860,301	$19,486,204	$19,138,853	$18,864,856	$18,682,653	$18,552,912	
Return on Average Net Working Capital Balance (A)															
a. Debt Component (Line 3 x 2.46% x 1/12)	2.46%		43,659	43,262	42,904	42,514	42,004	41,389	40,714	39,947	39,235	38,673	38,299	38,033	490,633
b. Equity Component Grossed Up For Taxes	7.80%		138,396	137,139	136,006	134,767	133,150	131,203	129,061	126,630	124,373	122,592	121,408	120,565	1,555,290
Total Return Component (B)			$182,055	$180,401	$178,910	$177,281	$175,154	$172,592	$169,775	$166,577	$163,608	$161,265	$159,707	$158,598	2,045,923
Expense Dr (Cr)															
a. 5090001 SO_2 Allowance Expense			24,853	20,933	20,697	30,359	36,548	33,967	37,218	38,989	27,926	23,634	8,001	10,136	313,262
b. 4074004 SO_2 Amortization Expense			(39,463)	(39,463)	(39,463)	(39,847)	(39,559)	(39,559)	(39,559)	(39,559)	(39,559)	(39,559)	(39,559)	(39,559)	(474,705)
c. 5090003 NOx Allowance Expense			228,094	191,963	194,162	215,212	294,909	313,129	353,958	397,148	309,755	265,795	146,093	174,369	3,084,589
d. Other															0
Net Expense (C)			213,484	173,434	175,397	205,724	291,898	307,538	351,617	396,578	298,123	249,871	114,536	144,947	2,923,146
Total System Recoverable Expenses (Lines 5 + 7)			$395,539	$353,835	$354,307	$383,005	$467,052	$480,130	$521,392	$563,155	$461,731	$411,136	$274,243	$303,545	4,969,069
a. Recoverable costs allocated to Energy			395,539	353,835	354,307	383,005	467,052	480,130	521,392	563,155	461,731	411,136	274,243	303,545	4,969,069
b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Jurisdictional Factor			0.99450	0.99640	0.99770	0.99810	0.99800	0.99790	0.99710	0.99680	0.99670	0.99660	0.99680	0.99720	
Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Retail Energy-Related Recoverable Costs (D)			$393,364	$352,561	$353,492	$382,277	$466,118	$479,121	$519,880	$561,353	$460,207	$409,738	$273,365	$302,695	4,954,171
Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 393,364	$ 352,561	$ 353,492	$ 382,277	$ 466,118	$ 479,121	$ 519,880	$ 561,353	$ 460,207	$ 409,738	$ 273,365	$ 302,695	$ 4,954,171

tes:
(A) Line 3 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

ıe	Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
	Plant-in-Service/Depreciation Base		1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	
	Less: Accumulated Depreciation		(218,544)	(222,088)	(225,632)	(229,176)	(232,720)	(236,264)	(239,808)	(243,352)	(246,896)	(250,440)	(253,984)	(257,528)	(261,072)	
	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
	Net Investment (Lines 2 + 3 + 4)		$1,717,564	$1,714,020	$1,710,476	$1,706,932	$1,703,388	$1,699,844	$1,696,300	$1,692,756	$1,689,212	$1,685,668	$1,682,124	$1,678,580	$1,675,036	
	Average Net Investment			$1,715,792	$1,712,248	$1,708,704	$1,705,160	$1,701,616	$1,698,072	$1,694,528	$1,690,984	$1,687,440	$1,683,896	$1,680,352	$1,676,808	
	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		3,517	3,510	3,503	3,496	3,488	3,481	3,474	3,467	3,459	3,452	3,445	3,437	41,729
	b. Equity Component Grossed Up For Taxes	7.80%		11,150	11,127	11,104	11,081	11,058	11,035	11,012	10,989	10,966	10,943	10,920	10,897	132,282
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Investment Expenses															
	a. Depreciation (C)			3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	42,528
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	1,593	19,116
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Total System Recoverable Expenses (Lines 7 + 8)			$19,804	$19,774	$19,744	$19,714	$19,683	$19,653	$19,623	$19,593	$19,562	$19,532	$19,502	$19,471	235,655
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$19,804	$19,774	$19,744	$19,714	$19,683	$19,653	$19,623	$19,593	$19,562	$19,532	$19,502	$19,471	235,655
)	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
ı	Demand Jurisdictional Factor - Production (Peaking)			0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
!	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
)	Retail Demand-Related Recoverable Costs (F)			18,997	18,968	18,939	18,910	18,881	18,852	18,823	18,794	18,765	18,736	18,707	18,677	226,050
ı	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$18,997	$18,968	$18,939	$18,910	$18,881	$18,852	$18,823	$18,794	$18,765	$18,736	$18,707	$18,677	$226,050

lotes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(in Dollars)

ne	Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
5	Net Investment (Lines 2 + 3 + 4)		$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	
6	Average Net Investment			$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	$289,107	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		593	593	593	593	593	593	593	593	593	593	593	593	$7,116
	b. Equity Component Grossed Up For Taxes	7.80%		1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	22,548
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.10%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007880		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Total System Recoverable Expenses (Lines 7 + 8)			$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	29,664
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	$2,472	29,664
0	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
1	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
2	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
3	Retail Demand-Related Recoverable Costs (F)			2,296	2,296	2,296	2,296	2,296	2,296	2,296	2,296	2,296	2,296	2,296	2,296	27,553
4	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,296	$2,296	$2,296	$2,296	$2,296	$2,296	$2,296	$2,296	$2,296	$2,296	$2,296	$2,296	$27,553

Notes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)
(CAIR Assets In-Service by Year End 2013)

Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	Period Total
Investments															
a. Expenditures/Additions			$0	$700,000	$406,568	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,106,568
b. Clearings to Plant			0	0	1,906,568	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
Plant-in-Service/Depreciation Base		1,267,660,945	1,267,660,945	1,267,660,945	1,269,567,513	1,269,567,513	1,269,567,513	1,269,567,513	1,269,567,513	1,269,567,513	1,269,567,513	1,269,567,513	1,269,567,513	1,269,567,513	
Less: Accumulated Depreciation		(91,215,996)	(93,586,272)	(95,956,548)	(98,328,786)	(100,702,987)	(103,077,188)	(105,451,389)	(107,825,590)	(110,199,791)	(112,573,992)	(114,948,193)	(117,322,394)	(119,696,595)	
CWIP - Non-Interest Bearing		800,000	800,000	1,500,000	0	0	0	0	0	0	0	0	0	0	
Net Investment (Lines 2 + 3 + 4)		$1,177,244,949	$1,174,874,673	$1,173,204,397	$1,171,238,727	$1,168,864,526	$1,166,490,325	$1,164,116,124	$1,161,741,923	$1,159,367,722	$1,156,993,521	$1,154,619,320	$1,152,245,119	$1,149,870,918	
Average Net Investment			$1,176,059,811	$1,174,039,535	$1,172,221,562	$1,170,051,626	$1,167,677,425	$1,165,303,224	$1,162,929,023	$1,160,554,822	$1,158,180,621	$1,155,806,420	$1,153,432,219	$1,151,058,018	
Return on Average Net Investment (B)															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,893,475	2,888,504	2,884,031	2,878,693	2,872,851	2,867,010	2,861,169	2,855,327	2,849,486	2,843,645	2,837,804	2,831,962	34,363,957
b. Equity Component Grossed Up For Taxes	8.02%		7,863,349	7,849,841	7,837,686	7,823,177	7,807,303	7,791,428	7,775,554	7,759,680	7,743,805	7,727,931	7,712,057	7,696,182	93,387,993
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Investment Expenses															
a. Depreciation (C)			2,370,276	2,370,276	2,372,238	2,374,201	2,374,201	2,374,201	2,374,201	2,374,201	2,374,201	2,374,201	2,374,201	2,374,201	28,480,599
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (D)			832,429	832,429	833,681	833,681	833,681	833,681	833,681	833,681	833,681	833,681	833,681	833,681	10,001,668
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Total System Recoverable Expenses (Lines 7 + 8)			$13,959,529	$13,941,050	$13,927,636	$13,909,752	$13,888,036	$13,866,320	$13,844,605	$13,822,889	$13,801,173	$13,779,458	$13,757,743	$13,736,026	$166,234,217
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$13,959,529	$13,941,050	$13,927,636	$13,909,752	$13,888,036	$13,866,320	$13,844,605	$13,822,889	$13,801,173	$13,779,458	$13,757,743	$13,736,026	$166,234,217
Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Retail Demand-Related Recoverable Costs (F)			12,966,309	12,949,144	12,936,685	12,920,073	12,899,902	12,879,731	12,859,561	12,839,390	12,819,220	12,799,050	12,778,880	12,758,708	154,406,652
Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$12,966,309	$12,949,144	$12,936,685	$12,920,073	$12,899,902	$12,879,731	$12,859,561	$12,839,390	$12,819,220	$12,799,050	$12,778,880	$12,758,708	$154,406,652

ns:
A) N/A
B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI and restated in Order PSC-12-0425-PAA-EU.
C) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
D) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
E) Line 9a x Line 10
F) Line 9b x Line 11
G) Beginning Balance differs from Form 42 8E p9 ending balance due to a correction to the depreciation expense for CAIR projects 7.4e and 7.4k in the 2012 Estimated / Actual filing in Exhibit (TGF-1).

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)
(CAIR Assets Not In-Service by Year End 2013)

Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Investments															
a. Expenditures/Additions			$150,000	$286,364	$286,364	$286,364	$286,364	$286,364	$336,364	$336,364	$336,364	$336,364	$336,364	$294,364	$3,558,000
b. Clearings to Plant			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	
d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
CWIP - Non-Interest Bearing		519,750	669,750	956,114	1,242,477	1,528,841	1,815,205	2,101,568	2,437,932	2,774,296	3,110,659	3,447,023	3,783,386	4,077,750	
Net Investment (Lines 2 + 3 + 4)		$519,750	$669,750	$956,114	$1,242,477	$1,528,841	$1,815,205	$2,101,568	$2,437,932	$2,774,296	$3,110,659	$3,447,023	$3,783,386	$4,077,750	
Average Net Investment			$594,750	$812,932	$1,099,296	$1,385,659	$1,672,023	$1,958,386	$2,269,750	$2,606,114	$2,942,477	$3,278,841	$3,615,205	$3,930,568	
Return on Average Net Investment (B)															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.46%		1,219	1,667	2,254	2,841	3,428	4,015	4,653	5,343	6,032	6,722	7,411	8,058	53,643
b. Equity Component Grossed Up For Taxes	7.80%		3,865	5,283	7,144	9,005	10,866	12,726	14,750	16,936	19,122	21,307	23,493	25,543	170,040
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Investment Expenses															
a. Depreciation (C)			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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (D)			0	0	0	0	0	0	0	0	0	0	0	0	0
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Total System Recoverable Expenses (Lines 7 + 8)			$5,084	$6,950	$9,398	$11,846	$14,294	$16,741	$19,403	$22,279	$25,154	$28,029	$30,904	$33,601	$223,683
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$5,084	$6,950	$9,398	$11,846	$14,294	$16,741	$19,403	$22,279	$25,154	$28,029	$30,904	$33,601	$223,683
Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Retail Demand-Related Recoverable Costs (F)			4,722	6,456	8,729	11,003	13,277	15,550	18,022	20,694	23,364	26,035	28,705	31,210	207,768
Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$4,722	$6,456	$8,729	$11,003	$13,277	$15,550	$18,022	$20,694	$23,364	$26,035	$28,705	$31,210	$207,768

Notes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Schedule of Amortization and Return
For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-products)
(in Dollars)

Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Working Capital Dr (Cr)															
a. 1544001 Ammonia Inventory		41,390	$41,390	$41,390	$41,390	$41,390	$41,390	$41,390	$41,390	$41,390	$41,390	$41,390	$41,390	$41,390	$41,390
b. 1544004 Limestone Inventory	(F)	832,642	$807,311	807,311	807,311	807,311	807,311	807,311	807,311	807,311	807,311	807,311	807,311	807,311	807,311
Total Working Capital		874,032	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701
Average Net Investment			861,367	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	848,701	
Return on Average Net Working Capital Balance	(A)														
a. Debt Component (Line 3 x 2.46% x 1/12)	2.46%		1,766	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	$20,904
b. Equity Component Grossed Up For Taxes	7.80%		5,598	5,515	5,515	5,515	5,515	5,515	5,515	5,515	5,515	5,515	5,515	5,515	66,265
Total Return Component (B)			7,363	7,255	7,255	7,255	7,255	7,255	7,255	7,255	7,255	7,255	7,255	7,255	87,169
Expense Dr (Cr)															
a. 5020011 Ammonia Expense	(G)		(174,734)	162,863	145,753	150,561	165,856	173,727	174,491	181,227	172,577	176,371	157,299	204,741	1,690,733
b. 5020012 Limestone Expense			456,888	394,955	351,375	364,210	431,211	451,039	451,271	467,057	443,929	452,562	405,993	521,411	5,191,901
c. 5020013 Dibasic Acid Expense			0	0	20,000	0	0	20,000	0	0	20,000	0	0	20,000	80,000
d. 5020003 Gypsum Disposal/Sale			233,411	201,775	179,416	186,198	220,578	230,776	230,877	239,133	227,360	231,752	207,766	266,983	2,656,027
e. 5020014 Bottom/Fly Ash Reagents Expense			94,182	81,426	72,217	75,394	89,563	93,810	93,817	97,524	92,856	94,591	84,530	108,921	1,078,831
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Net Expense	(C)		609,747	841,019	768,761	776,364	907,208	969,352	950,457	984,941	956,723	955,276	855,588	1,122,056	10,697,492
Total System Recoverable Expenses (Lines 5 + 7)			$617,110	$848,274	$776,016	$783,619	$914,464	$976,607	$957,712	$992,196	$963,978	$962,531	$862,843	$1,129,311	$10,784,661
a. Recoverable costs allocated to Energy			617,110	848,274	776,016	783,619	914,464	976,607	957,712	992,196	963,978	962,531	862,843	1,129,311	10,784,661
b. Recoverable costs allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Jurisdictional Factor			0.99450	0.99640	0.99770	0.99810	0.99800	0.99790	0.99710	0.99680	0.99670	0.99660	0.99680	0.99720	
Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Retail Energy-Related Recoverable Costs (D)			613,716	845,221	774,231	782,130	912,635	974,557	954,934	989,021	960,797	959,258	860,082	1,126,149	10,752,730
Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 613,716	$ 845,221	$ 774,231	$ 782,130	$ 912,635	$ 974,557	$ 954,934	$ 989,021	$ 960,797	$ 959,258	$ 860,082	$ 1,126,149	$ 10,752,730

Notes:
(A) Line 3 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10
(F) Adjustment to reduce 2012 Estimated Limestone Inventory in January 2013 approx. $25K.
(G) Adjustment to reduce 2012 Estimated (July-Dec) Ammonia Expense amount in January 2013 approx. $350K.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
1	Investments															
	a. Expenditures/Additions			$208	$208	$208	$208	$208	$208	$208	$208	$208	$208	$208	$208	$2,500
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	
3	Less: Accumulated Depreciation		(1,636)	(1,662)	(1,688)	(1,714)	(1,740)	(1,766)	(1,792)	(1,818)	(1,844)	(1,870)	(1,896)	(1,922)	(1,948)	
4	CWIP - Non-Interest Bearing		1,700	1,908	2,117	2,325	2,533	2,742	2,950	3,158	3,367	3,575	3,783	3,992	4,200	
5	Net Investment (Lines 2 + 3 + 4)		$10,263	$10,445	$10,628	$10,810	$10,992	$11,175	$11,357	$11,539	$11,722	$11,904	$12,086	$12,269	$12,451	
6	Average Net Investment			10,354	10,537	10,719	10,901	11,084	11,266	11,448	11,631	11,813	11,995	12,178	12,360	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		21	22	22	22	23	23	23	24	24	25	25	25	$279
	b. Equity Component Grossed Up For Taxes	7.80%		67	68	70	71	72	73	74	76	77	78	79	80	885
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.10%		26	26	26	26	26	26	26	26	26	26	26	26	312
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.009674		8	8	8	8	8	8	8	8	8	8	8	8	96
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$122	$124	$126	$127	$129	$130	$131	$134	$135	$137	$138	$139	$1,572
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$122	$124	$126	$127	$129	$130	$131	$134	$135	$137	$138	$139	$1,572
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)			0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			121	123	125	126	128	129	130	133	134	136	137	138	1,565
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$121	$123	$125	$126	$128	$129	$130	$133	$134	$136	$137	$138	$1,565

Notes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Base (Project 10.1)
(in Dollars)

ine	Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		(24,688)	(24,984)	(25,280)	(25,576)	(25,872)	(26,168)	(26,464)	(26,760)	(27,056)	(27,352)	(27,648)	(27,944)	(28,240)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$144,253	$143,957	$143,661	$143,365	$143,069	$142,773	$142,477	$142,181	$141,885	$141,589	$141,293	$140,997	$140,701	
6	Average Net Investment			144,105	143,809	143,513	143,217	142,921	142,625	142,329	142,033	141,737	141,441	141,145	140,849	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		295	295	294	294	293	292	292	291	291	290	289	289	$3,505
	b. Equity Component Grossed Up For Taxes	7.80%		936	935	933	931	929	927	925	923	921	919	917	915	11,111
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.10%		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007880		111	111	111	111	111	111	111	111	111	111	111	111	1,332
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,638	$1,637	$1,634	$1,632	$1,629	$1,626	$1,624	$1,621	$1,619	$1,616	$1,613	$1,611	$19,500
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,638	$1,637	$1,634	$1,632	$1,629	$1,626	$1,624	$1,621	$1,619	$1,616	$1,613	$1,611	$19,500
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			1,521	1,521	1,518	1,516	1,513	1,510	1,508	1,506	1,504	1,501	1,498	1,496	18,113
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,521	$1,521	$1,518	$1,516	$1,513	$1,510	$1,508	$1,506	$1,504	$1,501	$1,498	$1,496	$18,113

Notes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

ne	Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
	Plant-in-Service/Depreciation Base		76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
	Less: Accumulated Depreciation		(14,477)	(14,680)	(14,883)	(15,086)	(15,289)	(15,492)	(15,695)	(15,898)	(16,101)	(16,304)	(16,507)	(16,710)	(16,913)	
	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
	Net Investment (Lines 2 + 3 + 4)		$61,529	$61,326	$61,123	$60,920	$60,717	$60,514	$60,311	$60,108	$59,905	$59,702	$59,499	$59,296	$59,093	
	Average Net Investment			61,428	61,225	61,022	60,819	60,616	60,413	60,210	60,007	59,804	59,601	59,398	59,195	
	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		126	126	125	125	124	124	123	123	123	122	122	121	1,484
	b. Equity Component Grossed Up For Taxes	7.80%		399	398	397	395	394	393	391	390	389	387	386	385	4,704
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Investment Expenses															
	a. Depreciation (C)	3.20%		203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.010140		64	64	64	64	64	64	64	64	64	64	64	64	768
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Total System Recoverable Expenses (Lines 7 + 8)			$792	$791	$789	$787	$785	$784	$781	$780	$779	$776	$775	$773	$9,392
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$792	$791	$789	$787	$785	$784	$781	$780	$779	$776	$775	$773	$9,392
	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	Retail Demand-Related Recoverable Costs (F)			576	575	574	572	571	570	568	567	566	564	563	562	6,828
	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$576	$575	$574	$572	$571	$570	$568	$567	$566	$564	$563	$562	$6,828

otes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: CRYSTAL RIVER THERMAL DISCHARGE COMPLIANCE PROJECT - AFUDC - Base (Project 11.1)
(in Dollars)

Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Investments															
a. Expenditures/Additions			17,495	17,495	17,495	17,495	17,495	17,495	17,495	17,495	17,495	17,495	17,495	17,495	209,940
b. Clearings to Plant			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	
d. Other (A)			110,984	111,780	112,581	113,387	114,198	115,014	115,835	116,661	117,493	118,329	119,171	120,018	
Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
Less: Accumulated Depreciation		(20,866)	(21,378)	(21,890)	(22,402)	(22,914)	(23,426)	(23,938)	(24,450)	(24,962)	(25,474)	(25,986)	(26,498)	(27,010)	
CWIP - AFUDC Bearing		17,901,488	18,029,967	18,159,242	18,289,318	18,420,200	18,551,893	18,684,402	18,817,733	18,951,889	19,086,877	19,222,701	19,359,367	19,496,880	
Net Investment (Lines 2 + 3 + 4)		$18,242,358	$18,370,325	$18,499,088	$18,628,652	$18,759,022	$18,890,203	$19,022,200	$19,155,018	$19,288,663	$19,423,138	$19,558,451	$19,694,605	$19,831,605	
Average Net Investment (B)			$340,614	$340,102	$339,590	$339,078	$338,566	$338,054	$337,542	$337,030	$336,518	$336,006	$335,494	$334,982	
Return on Average Net Investment (C)															
a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		698	697	696	695	694	693	692	691	690	689	688	687	8,310
b. Equity Component Grossed Up For Taxes	7.80%		2,213	2,210	2,207	2,203	2,200	2,197	2,193	2,190	2,187	2,184	2,180	2,177	26,341
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Investment Expenses															
a. Depreciation (D)			512	512	512	512	512	512	512	512	512	512	512	512	6,144
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	N/A
d. Property Taxes (E)			280	280	280	280	280	280	280	280	280	280	280	280	3,360
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			$3,703	$3,699	$3,695	$3,690	$3,686	$3,682	$3,677	$3,673	$3,669	$3,665	$3,660	$3,656	$44,155
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$3,703	$3,699	$3,695	$3,690	$3,686	$3,682	$3,677	$3,673	$3,669	$3,665	$3,660	$3,656	$44,155
10 Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11 Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12 Retail Energy-Related Recoverable Costs (F)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13 Retail Demand-Related Recoverable Costs (G)			3,440	3,436	3,432	3,427	3,424	3,420	3,415	3,412	3,408	3,404	3,400	3,396	41,013
14 Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$3,440	$3,436	$3,432	$3,427	$3,424	$3,420	$3,415	$3,412	$3,408	$3,404	$3,400	$3,396	$41,013

Notes:
(A) AFUDC rate reflected within Docket 120022-EI per Order PSC-12-0104-PAA-EI.
(B) Line represents the Average Net Investment excluding AFUDC interest-bearing CWIP projects. Refer to Capital Program Detail for Average Net Investment Return on which Line 7 is calculated.
(C) Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(D) Depreciation calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 120007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-3R)
Page 18 of 44

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: NPDES (Project 16)
(in Dollars)

e Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
Investments															
a. Expenditures/Additions			$110,000	$50,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	160,000
b. Clearings to Plant			110,000	50,000	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
Plant-in-Service/Depreciation Base		2,323,361	2,433,361	2,483,361	2,483,361	2,483,361	2,483,361	2,483,361	2,483,361	2,483,361	2,483,361	2,483,361	2,483,361	2,483,361	
Less: Accumulated Depreciation		(3,195)	(9,887)	(16,716)	(23,545)	(30,374)	(37,204)	(44,033)	(50,862)	(57,691)	(64,521)	(71,350)	(78,179)	(85,008)	
CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
Net Investment (Lines 2 + 3 + 4)		$2,320,166	$2,423,474	$2,466,645	$2,459,816	$2,452,987	$2,446,157	$2,439,328	$2,432,499	$2,425,670	$2,418,840	$2,412,011	$2,405,182	$2,398,353	
Average Net Investment			2,371,820	2,445,060	2,463,230	2,456,401	2,449,572	2,442,743	2,435,913	2,429,084	2,422,255	2,415,426	2,408,596	2,401,767	
Return on Average Net Investment (B)															
a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		4,862	5,012	5,050	5,036	5,022	5,008	4,994	4,980	4,966	4,952	4,938	4,924	59,744
b. Equity Component Grossed Up For Taxes	7.80%		15,413	15,889	16,007	15,963	15,918	15,874	15,830	15,785	15,741	15,697	15,652	15,608	189,377
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
Investment Expenses															
a. Depreciation (C)	3.30%		6,692	6,829	6,829	6,829	6,829	6,829	6,829	6,829	6,829	6,829	6,829	6,829	81,813
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (D)	0.010140		2,056	2,098	2,098	2,098	2,098	2,098	2,098	2,098	2,098	2,098	2,098	2,098	25,139
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			$29,023	$29,829	$29,985	$29,927	$29,868	$29,810	$29,752	$29,693	$29,635	$29,577	$29,518	$29,460	$356,073
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$29,023	$29,829	$29,985	$29,927	$29,868	$29,810	$29,752	$29,693	$29,635	$29,577	$29,518	$29,460	$356,073
10 Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11 Demand Jurisdictional Factor - Production (Intermediate))			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12 Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13 Retail Demand-Related Recoverable Costs (f)			21,101	21,686	21,800	21,758	21,715	21,673	21,630	21,587	21,545	21,503	21,460	21,418	258,876
14 Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$21,101	$21,686	$21,800	$21,758	$21,715	$21,673	$21,630	$21,587	$21,545	$21,503	$21,460	$21,418	$258,876

otes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury & Air Toxic Standards (MATS) - Energy (Crystal River 4 & 5) (Project 17)
(in Dollars)

e	Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
	Investments															
	a. Expenditures/Additions			$20,000	$20,000	$20,000	$70,000	$70,000	$500,000	$3,000,000	$2,000,000	$1,500,000	$1,500,000	$1,100,000	$200,000	10,000,000
	b. Clearings to Plant			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	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
	CWIP - Non-Interest Bearing		1,250,930	1,270,930	1,290,930	1,310,930	1,380,930	1,450,930	1,950,930	4,950,930	6,950,930	8,450,930	9,950,930	11,050,930	11,250,930	
	Net Investment (Lines 2 + 3 + 4)		$1,250,930	$1,270,930	$1,290,930	$1,310,930	$1,380,930	$1,450,930	$1,950,930	$4,950,930	$6,950,930	$8,450,930	$9,950,930	$11,050,930	$11,250,930	
	Average Net Investment			$1,260,930	$1,280,930	$1,300,930	$1,345,930	$1,415,930	$1,700,930	$3,450,930	$5,950,930	$7,700,930	$9,200,930	$10,500,930	$11,150,930	
	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		2,585	2,626	2,667	2,759	2,903	3,487	7,074	12,199	15,787	18,862	21,527	22,859	115,335
	b. Equity Component Grossed Up For Taxes	7.80%		8,194	8,324	8,454	8,746	9,201	11,053	22,426	38,672	50,044	59,792	68,240	72,464	365,610
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Investment Expenses															
	a. Depreciation (C)	2.50%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.00831		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$10,779	$10,950	$11,121	$11,505	$12,104	$14,540	$29,500	$50,871	$65,831	$78,654	$89,767	$95,323	$480,945
	a. Recoverable Costs Allocated to Energy			10,779	10,950	11,121	11,505	12,104	14,540	29,500	50,871	65,831	78,654	89,767	95,323	480,945
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Energy Jurisdictional Factor			0.99450	0.99640	0.99770	0.99810	0.99800	0.99790	0.99710	0.99680	0.99670	0.99660	0.99680	0.99720	
11	Demand Jurisdictional Factor - Production (Intermediate)			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (E)			10,720	10,911	11,095	11,483	12,080	14,509	29,414	50,708	65,614	78,387	89,480	95,056	479,457
13	Retail Demand-Related Recoverable Costs (f)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$10,720	$10,911	$11,095	$11,483	$12,080	$14,509	$29,414	$50,708	$65,614	$78,387	$89,480	$95,056	$479,457

lotes:
(A) N/A
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2011 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 through December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury & Air Toxic Standards (MATS) - Energy - (Anclote Gas Conversion) (Project 17.1)
(in Dollars)

e	Description		Beginning of Period Amount	Projected January 13	Projected February 13	Projected March 13	Projected April 13	Projected May 13	Projected June 13	Projected July 13	Projected August 13	Projected September 13	Projected October 13	Projected November 13	Projected December 13	End of Period Total
	Investments															
	a. Expenditures/Additions			$3,211,333	$6,151,314	$3,908,867	$4,426,070	$4,806,458	$3,148,449	$1,924,562	$3,594,500	$2,589,943	$2,685,105	$3,006,208	$8,426,812	47,879,621
	b. Clearings to Plant			0	0	0	0	0	36,287,646	0	0	0	0	0	36,352,419	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			146,544	175,487	206,695	232,918	261,989	287,404	86,789	103,853	123,013	139,563	157,459	0	
	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	36,287,646	36,287,646	36,287,646	36,287,646	36,287,646	36,287,646	72,640,065	
	Less: Accumulated Depreciation		0	0	0	0	0	0	(33,264)	(99,791)	(166,318)	(232,848)	(299,373)	(365,900)	(465,751)	
	CWIP - AFUDC Interest Bearing		22,838,730	26,196,608	32,523,409	36,638,970	41,297,958	46,366,405	13,514,812	15,525,963	19,224,316	21,937,272	24,761,940	27,925,607	0	
	Net Investment (Lines 2 + 3 + 4)		$22,838,730	$26,196,608	$32,523,409	$36,638,970	$41,297,958	$46,366,405	$49,768,994	$51,713,818	$55,345,643	$57,992,072	$60,750,213	$63,847,353	$72,174,314	
	Average Net Investment (Excluding AFUDC Eligible)			$0	$0	$0	$0	$0	$18,127,191	$36,221,119	$36,154,591	$36,088,064	$36,021,537	$35,955,009	$54,048,030	
	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		0	0	0	0	0	37,161	74,253	74,117	73,981	73,844	73,708	110,798	517,862
	b. Equity Component Grossed Up For Taxes	7.80%		0	0	0	0	0	117,798	235,381	234,948	234,516	234,084	233,651	351,228	1,641,607
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	Investment Expenses															
	a. Depreciation (C)	2.20%		0	0	0	0	0	33,264	66,527	66,527	66,527	66,527	66,527	99,850	465,751
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.008310		0	0	0	0	0	25,129	25,129	25,129	25,129	25,129	25,129	50,303	201,076
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$0	$0	$0	$0	$0	$213,352	$401,291	$400,722	$400,153	$399,584	$399,016	$612,180	$2,826,298
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	213,352	401,291	400,722	400,153	399,584	399,016	612,180	2,826,298
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Energy Jurisdictional Factor			0.99450	0.99640	0.99770	0.99810	0.99800	0.99790	0.99710	0.99680	0.99670	0.99660	0.99680	0.99720	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	212,904	400,127	399,440	398,833	398,226	397,739	610,466	2,817,734
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$212,904	$400,127	$399,440	$398,833	$398,226	$397,739	$610,466	$2,817,734

plies:
(A) AFUDC rate reflected within Docket 120022-EI per Order PSC-12-0104-PAA-EI. (AFUDC Monthly Compound Rate) 0.5995%
(B) Line 6 x 10.26% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.79%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on PEF's May 2012 Surveillance report per Order PSC-12-0425-PAA-EU.
(C) Line 2 x rate x 1/12.
(D) Line 2 x rate x 1/12.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Project Title: **Substation Environmental Investigation, Remediation, and Pollution Prevention**
Project No. 1

Project Description:
Chapter 376, Florida Statutes, requires that any person discharging a prohibited pollutant shall undertake to contain, remove, and abate the discharge to the satisfaction of the Florida Department of Environmental Protection (FDEP). Similarly, Chapter 403, Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For PEF to continue to comply with these statutes, it is conducting environmental investigation, remediation, and pollution prevention activities associated with its substation facilities to determine the existence of pollutant discharges, and if present, their removal and remediation. Activities also include development and implementation of best management and pollution prevention measures at these facilities.

Project Accomplishments:
PEF completed environmental remediations at 10 substations during 2012. Soil and groundwater sampling continue as well as remediation report writing. 245 remediations are completed out of 279 slated for completion. PEF is continuing to work with the FDEP on remaining remediations.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project expenditures are estimated to be approximately $1.2 million higher than originally projected. This variance is primarily due to multiple sites containing more contamination than originally projected as well as scheduling conflicts that resulted in sites being rescheduled from 2011 into 2012.

Project Progress Summary:
PEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

Project Projections:
Estimated project expenditures for 2013 are expected to be approximately $2.3 million.

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Project Title: **Distribution System Environmental Investigation, Remediation, and Pollution Prevention**
Project No. 2

Project Description:
Chapter 376, Florida Statutes, requires that any person discharging a prohibited pollutant shall undertake to contain, remove, and abate the discharge to the satisfaction of the Florida Department of Environmental Protection (FDEP). Similarly, Chapter 403, Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For Progress Energy Florida to continue to comply with these statutes, it is conducting environmental investigation, remediation, and pollution prevention activities associated with its distribution system facilities to determine the existence of pollutant discharges, and if present, their removal and remediation. Activities also include development and implementation of best management and pollution prevention measures at these facilities.

Project Accomplishments:
In 2012, PEF completed all of the remaining identified abatement sites for the Transformer Replacement & Inspection Program (TRIP) program and completed deviation sampling on 9 sites. The cost for deviation sampling and potential remediation work at these 9 sites are included in the 2013 estimated TRIP costs. All TRIP remediations have been conducted in accordance with the FDEP approved Environmental Remediation Strategy.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project expenditures are estimated to be approximately $0.2 million higher than originally projected as a result of the 5 carryover abatement sites and delayed submittal of invoices to PEF from vendors.

Project Progress Summary:
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

Project Projections:
Estimated project expenditures for 2013 are expected to be approximately $0.2 million.

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Project Title: **Pipeline Integrity Management, Review/Update Plan and Risk Assessments**
Project No. 3

Project Description:
The U.S. Department of Transportation ("USDOT") Regulation 49 CFR Part 195, as amended effective February 15, 2002 and the new regulation published at 67 Federal Register 2136 on January 16, 2002, requires PEF to implement a Pipeline Integrity Management Program. Prior to the February 15, 2002 amendments, the USDOT's pipeline integrity management regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on February 15, 2002 extended the requirements for implementing integrity management to operators who have less than 500 miles of regulated pipelines. As such, PEF must improve the integrity of pipeline systems in order to protect public safety and the environment, as well as comply with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis, and follow up with remedial, preventative, and mitigative actions.

Effective February 2010, amendments to 49 CFR 195 were finalized to improve opportunities to reduce risk through more effective control of pipelines. Compliance with these amendments will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management. On June 16, 2011, USDOT published in the Federal Register (Vol. 76, 35130-35136), a final rule effective August 15, 2011 that expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This final rule amends the program implementation deadlines for different procedures to no later than October 21, 2011, and August 1, 2012.

PEF owns one hazardous liquid pipeline that is subject to the new regulation and must comply with the new requirements for the Bartow/Anclote 14-inch hot oil pipeline, extending 33.3 miles from the Company's Bartow Plant north of St. Petersburg to the Anclote Plant in Holiday.

Project Accomplishments:

PEF has developed pipeline control room management procedures and trained Pipeline Terminal Operators on said procedures. PEF has also procured a pipeline operations simulator to be used to train Pipeline Terminal Operators. PEF completed the second In Line Inspection (Smart Pig) in late 2009. Smart pig data validation, corrosion rate calculations, anomaly ranking, repair planning, inspection interval determination, risk analysis updates, spill consequence updates, data alignment, and biennial review activities are ongoing. Since mid-2010 PEF has completed repairs and validations based on the Smart Pig findings. These findings required completion of three immediate repairs, one 60-Day repair, one 180-Day repair, and six other repairs along with several risk reduction projects. Risk reduction coordination is ongoing for third party projects at U.S. Highway 19 and Haines Bayshore Road, 9th Street and Gandy Boulevard, 118th Avenue, Progress Energy Trail, and Spruce Street. In June 2011, a sinkhole opened up in close proximity to the pipeline. Geotechnical testing was undertaken along a two mile length of the pipeline that is located in an active sinkhole area. Two large voids were found under the pipeline that required injection grouting to prevent collapse.

Project Fiscal Expenditures:

January 1, 2012 to December 31, 2012: O&M project expenditures are estimated to be approximately $0.1 million lower than originally projected .

Project Progress Summary:
Ongoing Smart Pig anomaly evaluation, data validation, corrosion rate calculations, repair ranking, repair implementation, program biennial review activities, and third party project coordination continue. This compliance work will continue through the end of 2012. 2013 O&M costs are to comply with the Pipeline Integrity Management regulations (49 CFR Part 195). These costs include general program management and oversight of the performance of program activities.

Project Projections:
For 2013 O&M expenditures are expected to be approximately $0.6M. There are no expected capital expenditures.

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Project Title: **Above Ground Storage Tank Secondary Containment**
Project No. 4

Project Description:
Florida Department of Environmental Protection Rule 62-761.510(3) states that the Company is required to make improvements to many of its above ground petroleum storage tanks in order to comply with those provisions. Subsection (d) of that rule requires all internally lined single bottom above ground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. Rule 62-761.500(1)(e) also requires that dike field area containment for pre-1998 tanks be upgraded, if needed, to comply with the requirement.

Project Accomplishments:
PEF has completed work at: DeBary 1, Turner 7, Turner 8, Higgins 1, and Bartow 6 as well as Turner P-1 and P-2 piping work. DeBary 2 was completed in 2011.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: There are no projected O&M project expenditures for this project in 2012. Capital expenditures are projected to be approximately $5,000 to finalize the project.

Project Progress Summary:
PEF will continually evaluate its compliance program, including project prioritization, schedule, and technology applications.

Project Projections:
PEF projects no expenditures in 2013 related to this program.

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Project Title: **Integrated Clean Air Compliance Plan - SO_2 and NOx Emissions Allowances**
Project No. 5

Project Description:
In accordance with the Acid Raint Program inTitle IV of the Clean Air Act, CFR 40 Part 73 and Part 76, and Florida Administrative Code Rule 62-214 and the Clean Air Interstate Rule (CAIR), PEF manages sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions allowance inventories for the purpose of offsetting SO2 and NOx emission. On 7/6/11, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace CAIR. CSAPR would significantly alter the SO2 and NOx allowance programs. Under CAIR, Florida is required to comply with annual SO2 and NOx emission requirements and seasonal requirements regulating NOx emissions during the ozone season. Under CSAPR, Florida would no longer included in the group of states required to comply with annual emissions requirements; it would only be covered by the seasonal ozone requirements. However, on 8/21/12, the U.S. Court of Appeals for the District of Columbia vacated CSAPR, leaving CAIR in effect until EPA adopts a valid replacement. Further discussion of CSAPR is included in the testimony of Patricia Q. West.

Project Accomplishments:

For purposes of compliance with an affected unit's sulfur dioxide (SO_2) and nitrogen oxides (NOx) emissions requirements under the Acid Rain Program, air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases of SO_2 and NO_X emissions allowances as well as auctions and transfers of SO_2 emissions allowances.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project expenditures are estimated to be approximately $3 million lower than originally projected. This variance is driven by lower actual NOx allowance expense due to usage than the estimated 2012 NOx allowance expense resulting from the 3yr amortization calculation presented in Docket No. 110007-EI.

Project Progress Summary:
PEF continually evaluates the status of CSARP and CAIR rules to maximize the cost effectiveness of its compliance strategy.

Project Projections:
For 2013 SO_2 expenditures are expected to be approximately $0.3 million and NOx expenses are expected to be approximately $3.1 million.

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Project Title: **Phase II Cooling Water Intake**
Project No. 6

Project Description:

Section 316(b) of the Federal Clean Water Act, requires that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." 33 U.S.C. Section 1326. In the past, EPA and the state regulatory agency implemented Section 316(b) on a case-by-case basis. In the new Phase II rules, EPA has established "national performance standards" for determining compliance with Section 316(b) at certain existing electric generating facilities. See 40 CFR 125.94(b). The process of compliance involves planning and scheduling efforts, conducting certain biological studies, and evaluation of options for compliance. These compliance options involve engineering measures, operational measures, restorative measures and/or cost assessment measures. See generally 40 CFR 125.94 and 125.95. The EPA is expected to final new Phase II rules in June 2013.

Project Accomplishments:

PEF facilities subject to EPA's new Phase II rules include Anclote, Bartow, Crystal River and Suwannee plants. Early in 2004 PEF requested competitive bids for an environmental consultant to support the development of a Compliance Strategy and Implementation Plan (CSIP); that contract was secured and the CSIP is now complete. The consultant completed a Proposals for Information Collection (PICs) for Anclote & Bartow, Crystal River, and Suwannee and they have been submitted and approved by the FDEP.

Project Fiscal Expenditures:

January 1, 2012 - December 31, 2012: Due to a federal courts vacatur of the Phase II rules, the estimated project O&M expenditures for the period January 2012 through December 2012 are projected to be $0.

Project Progress Summary:

As a result of the July 17, 2012 second amendment to the settlement agreement among the U.S. Environmental Protection Agency (EPA) and plaintiffs, EPA is expected to issue a final rule establishing cooling water intake standards pursuant to Section 316(b) of the Clean Water Act rule in June 2013. The proposed rule would establish standards for impingement mortality that can be achieved in either one of two ways: 1) modify traveling intake screens with fish collection and return systems that demonstrate that 88% of the fish collected will survive the process or 2) reduce the intake flow velocity to 0.5 feet per second. The proposed 316(b) rules would establish that state permitting authorities (FDEP in Florida) determine requirements for entrainment mortality on a case-by-case, site specific basis. The permittee must collect data, conduct studies and submit information that would be used by the state permitting authorities to make its decision. Permittees would also be required to include an evaluation of a closed-cycle, re-circulating cooling system (cooling towers) retrofit as part of their entrainment studies. PEF is assessing several options that may be required to comply with the rule. The options under consideration may change once the final rule is issued and its impacts better understood, therefore the exact costs that PEF will incur under 316(b) cannot be predicted.

Project Projections:
For the period January 2013 through December 2013 PEF does not expect any expenditures.

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Project Title: **Integrated Clean Air Compliance Plan - Clean Air Interstate Rule (CAIR)**
Project Nos. (7.2, 7.3, & 7.4)

Project Description:
Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant new restrictions on emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") from power plants in 28 eastern states, including Florida, and the District of Columbia. The CAIR rule apportions region-wide SO_2 and NOx emission reduction requirements to the individual states, and further required each affected state to revise its State Implementation Plans (SIP) to include measures necessary to achieve its emission reduction budget within prescribed deadlines.

Project Accomplishments:
During 2012, the project team focused on completing the installation of the Hydrated Lime Injection System.

Project Fiscal Expenditures:
January 1, 2013 - December 31, 2013: PEF's capital expenditures for CAIR will be approximately $23.2 million lower than PEF's 2012 Projection filing. The difference is primarily attributable to the completion of the Hydrated Lime and SO3 probes projects in 2012.

Project Progress Summary:

For FGD Blowdown treatment, a wastewater treatment study is currenltly being performed by CH2MHill; the study is estimated to complete in October 2012. The study is being conducted in accordance with Conditions of Certification Modification P which requires the submission of an evaluation of alternative(s) to manage FGD blowdown.

Project Projections:
PEF expects approximately $27.9 million in O&M expenses and approximately $4.7 million in capital expenditures for this program.

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Project Title: **Integrated Clean Air Compliance Plan - Best Available Retrofit Technology (BART)**
Project No. 7.5

Project Description:
On May 25, 2012, the Environmental Protection Agency (EPA) proposed a partial disapproval of Florida's proposed Regional Haze State Implementation Plan (SIP) because the proposed SIP relies on CAIR to satisfy BART requirements for SO2 and NOx emissions. Although CAIR remains in effect while litigation against the Cross State Air Pollution Rule (CSAPR) proceeds, the EPA is requiring states to incorporate the Cross State Air Pollution Rule (CSAPR) in place of CAIR in their Regional Haze SIPs. PEF has been working with the FDEP to develop a specific BART and Reasonable Progress permits for affected units that will be incorporated into Florida's revised SIP submittal, which is due to be submitted to EPA by July 31, 2012.

Project Accomplishments:
Performed required emissions modeling and associated BART analysis for Crystal River Units 1 & 2 and Anclote plants, developed and submitted Reasonable Progress evaluation for Crystal River Units 4 & 5, developed and submitted necessary BART Implementation Plans and air construction permit applications needed in support of the Florida Department of Environmental Protection's (FDEP) ongoing work to amend its State Implementation Plan as directed by the EPA.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: PEF expects O&M project expenditures for the year of $27,000.

Project Progress Summary:
Performed required emissions modeling and associated BART analysis for Crystal River Units 1 & 2 and Anclote plants, developed and submitted Reasonable Progress evaluation for Crystal River Units 4 & 5, developed and submitted necessary BART Implementation Plans and air construction permit applications needed in support of the FDEP ongoing work to amend its State Implementation Plan as directed by the EPA.

Project Projections:
For the period January 2013 through December 2013 PEF expects $16,000 of O&M expenditures.

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Project Title: **Arsenic Groundwater Standard**
Project No. 8

Project Description:
On January 22, 2001, the U.S. Environmental Protection Agency (USEPA) adopted a new maximum contaminant level (MCL) for arsenic in drinking water, replacing the previous standard of 0.050 mg/L (50ppb) with a new MCL of 0.010 mg/L (10ppb). Effective January 1, 2005, FDEP established the USEPA MCL as Florida's drinking water standard. See Rule 62-550, F.A.C. The new standard has implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous PEF sites.

Project Accomplishments:
Routine quarterly sampling of existing monitoring wells continues as required by the Industrial Wastewater Permit No. FLA016960. A groundwater plan of study (POS), involving the investigation of sources of arsenic, will continue through 2012.

Project Fiscal Expenditures:
January 1, 2012 - December 31, 2012: PEF is not expecting to spend any dollars on this project in 2012.

Project Progress Summary:
PEF will finsh and submit results of the POS during the first quarter, 2013. Next steps will likely involve submittal of a parameter exemption petition to FDEP.

Project Projections:
PEF expects approximately $31,000 in expenditures for this project in 2013 to finish the groundwater POS and to complete a parameter exemption petition submittal.

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Project Title: **Sea Turtle - Coastal Street Lighting**
Project No. 9

Project Description:
PEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the Florida Department of Environmental Protection (FDEP), in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. The model ordinance is used by the local governments to develop and implement ordinances within their jurisdiction. To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County, City of Mexico Beach in Bay County and Pinellas County, all of which are within PEF's service territory. Since 2004, officials from the various local governments, as well as FDEP, FFWC, and USFWS, have advised PEF that lighting it owns and leases is affecting turtle nesting areas that fall within the scope of these ordinances. As a result, the local governments are requiring PEF to take additional measures to satisfy new criteria being applied to ensure compliance with the sea turtle ordinances.

Project Accomplishments:
PEF continues working with Franklin County, Gulf County, City of Mexico Beach and Pinellas County to mitigate any potential sea turtle nesting issues by retrofitting existing street lights, placing amber shields on existing HPS street lights and monitoring street lights for effectiveness in complying with sea turtle ordinances.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project expenditures are estimated to be approximately $2,500 lower than originally projected. This variance is primarily due to installing amber shields on a smaller quantity of street lights to prevent turtle disorientation than intially anticipated.

Project Progress Summary:
PEF is on schedule with the activities identified for this program.

Project Projections:
Estimated project expenditures for 2013 are expected to be approximately $5,000.

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Project Title: **Underground Storage Tanks**
Project No. 10

Project Description:
FDEP rules require that underground pollutant storage tanks and small diameter piping be upgraded with secondary containment by December 31, 2009. See Rule 62-761.510(5), F.A.C. PEF has identified four tanks that must comply with this rule: two at the Crystal River power plant and two at the Bartow power plant.

Project Accomplishments:
Work on Crystal River and Bartow USTs was completed in the fourth quarter 2006.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: $0 was projected to be spent in 2012.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Project Title: **Modular Cooling Towers**
Project No. 11

Project Description:
The project involves installation and operation of modular cooling towers in the summer months to minimize "de-rates" of PEF's Crystal River Units 1 and 2 necessary to comply with the NPDES permit limit for the temperature of cooling water discharged from the units.

Project Accomplishments:
Vendors of modular cooling towers were evaluated regarding cost of installation and operation. The Florida Department of Environmental Protection reviewed the project and approved operation. A vendor was selected and the towers were installed during the second quarter of 2006.

Project Fiscal Expenditures:

January 1, 2012 to December 31, 2012: Project O&M costs are $0.9 million higher than projected.

Project Progress Summary:
Modular cooling towers began operation in June 2006 and have successfully minimized de-rates of Units 1 and 2. Towers were removed during the first half of 2012. This project is complete.

Project Projections:
PEF projects no expenditures in 2013 related to this program.

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Project Title: **Crystal River Thermal Discharge Compliance Project**
Project No. 11.1

Project Description:
This project will evaluate and implement the best long term solution to maintain compliance with the thermal discharge limit in FDEP industrial wastewater permit for Crystal River 1, 2 & 3 that is currently being addressed in the short term by the Modular Cooling Towers approved in Docket No. 060162- EI for ECRC recovery.

Project Accomplishments:
The Study phase of the project is complete. The recommendation is to replace the modular cooling towers in coordination with the cooling solution for the CR3 Extended Power Uprate (EPU) discharge canal cooling solution. The new cooling tower associated with the CR3 EPU will be sized to mitigate both the increased temperatures from the EPU as well as serve to replace the modular cooling towers, which were removed in 2012. This project will be impacted by both the final form of new environmental regulations and the repair plan and timing of completing the Crystal River Unit 3 delamination work.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: Project costs are $0.6 million higher than projected; PEF did not file estimated costs for this project in the 2012 Projection filing.

Project Progress Summary:
The design contract for the CR3 EPU cooling tower has been awarded and a cooling tower supplier has been selected.

Project Projections:
Cost estimates for this project will be impacted by both the final form of new environmental regulations, and the repair plan and timing of completing Crystal River 3 delamination work. Current estimates are presented in schedule 42-4P p 14 of 17.

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Project Title: **Integrated Clean Air Compliance Plan - Greenhouse Gas Inventory and Reporting**
Project No. 12

Project Description:
The Greenhouse Gas (GHG) Inventory and Reporting Program was created in response to Chapter 2008-277, Florida Laws, which established the Florida Climate Protection Act, to be codified at section 403.44, Florida Statutes. Among other things, this legislation authorizes FDEP to establish a cap and trade program to GHG emissions from electric utilities. Utilities subject to the program, including PEF, will be required to use The Climate Registry for purposes of GHG emission registration and reporting.

The requirement to report to The Climate Registry was repealed during the 2010 legislative session; however, EPA's GHG Reporting Rule (40 CFR 98) does require that PEF submit 2010 GHG data to the EPA by March 31, 2011.

Project Accomplishments:
In 2009, Progress Energy joined The Climate Registry and submitted the 2008 GHG inventory data. The 2009 data was submitted during the third quarter of 2010. Both 2008 and 2009 data was validated by a third party as required by The Climate Registry. The 2010 GHG inventory data will be submitted to EPA by September 30, 2011 and validation by a third party is not a requirement.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: $0 was projected to be spent in 2012.

Project Progress Summary:
The 2010 GHG inventory data was submitted to EPA on September 30, 2011.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Project Title: **Mercury Total Daily Maximum Loads Monitoring (TMDL)**
Project No. 13

Project Description:
Section 303(d) of the federal Clean Water Act requires each state to identify state waters not meeting water quality standards and establish a TMDL for the pollutant or pollutants causing the failure to meet standards. Under a 1999 federal consent decree, TMDLs for over 100 Florida water bodies listed as impaired for mercury must be established by September 12, 2012. DEP has initiated a research program to provide the necessary information for setting the appropriate TMDLs for mercury. Among other things, the study will assess the relative contributions of mercury-emitting sources, such as coal-fired power plants, to mercury levels in surface waters.

Project Accomplishments:
Atmospheric & Environmental Research, Inc (AER) completed the literature review on mercury deposition in Florida; this document was sent to the FDEP Division of Air Resource Management and the TMDL team for review in February 2009. In addition, the Florida Electric Power Coordinating Group (FCG) Mercury Task Force met with the FDEP Division of Air Resource Management to discuss the review in January 2010. AER performed the Florida mercury deposition modeling for the Division of Air Resource Management. The FCG Mercury Task Force contracted with Tetra Tech to conduct aquatic field sampling, including an aquatics modeling report, to develop a "Conceptual Model for the Florida Mercury TMDL." This document was finalized and submitted to the FDEP in December 2010. Key personnel from AER were employed by Environ in 2011 and FCG established a contract with Environ to ensure continuity of the project. FCG used Environ and Tetra Tech to review and critique the FDEP's aquatic cycling and atmospheric modeling analyses. The FDEP has developed a draft mercury TMDL report, and it is scheduled to issue a proposed TMDL in September, 2012.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: $0 was projected to be spent in 2012.

Project Progress Summary:
The project is expected to conclude in 2012.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Project Title: **Integrated Clean Air Compliance Plan - Hazardous Air Pollutants (HAPs) ICR Program**
Project No. 14

Project Description:

In 2009, the U.S. Environmental Protection Agency (EPA) initiated efforts to develop an Information Collection Request ("ICR"), which requires that owners/operators of all coal- and oil-fired electric utility steam generating units provide information that will allow the EPA to assess the emissions of hazardous air pollutants from each such unit. The intention of the ICR is to assist the Administrator of the EPA in developing national emission standards for hazardous air pollutants under Section 112(d) of the Clean Air Act, 42 U.S.C. 7412. Pursuant to those efforts, by letter dated December 24, 2009, the EPA formally requested that PEF comply with certain data collection and emissions testing requirements for several of its steam electric generating units. The EPA letter states that initial submittal of existing information must be made within 90 days, and that the remaining data must be submitted within 8 months. Collection and submittal of the requested information is mandatory under Section 114 of the Clean Air Act, 42 U.S.C. 7414.

Project Accomplishments:
PEF completed and submitted the ICR to EPA during 2010. The HAPS ICR project is complete.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: No project expenditures for 2012 were incurred or budgeted.

Project Progress Summary:
PEF completed and submitted the ICR to EPA during 2010.

Project Projections:
PEF expects no expenditures for this project in 2013.

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Project Title: **Effluent Limitation Guidelines ICR Program**
Project No. 15

Project Description:
The Effluent Limitation Guidelines ICR Program was created in response to Section 304 of the federal Clean Water Act which directs the U.S. EPA to develop and periodically review regulations, called effluent guidelines, to limit the amount of pollutants that are discharged to surface waters from various point source categories. 33 U.S.C. §13 14(b). In October 2009, EPA announced that it intended to update the effluent guidelines for the steam electric power generating point source category, which were last updated in 1982. PEF is required to complete the ICR and submit responses to U.S. EPA within 90 days. Collection and submittal of the requested information is mandatory under Section 308 of the Clean Water Act.

Project Accomplishments:
PEF completed and submitted the ICR to EPA in September 2010. The Effluent Limitation Guidelines ICR Program is complete.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: No project expenditures for 2012 were incurred or budgeted.

Project Progress Summary:
PEF completed and submitted the ICR to EPA in September 2010.

Project Projections:
PEF expects no expenditures for this project in 2013.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **National Pollutant Discharge Elimination System (NPDES) - Energy**
Project No. 16

Project Description:
Pursuant to the federal Clean Water Act, 33 U.S.C. § 1342, all point source discharges to navigable waters from industrial facilities must obtain permits under the NPDES Program. The Florida Department of Environmental Protection (FDEP) administers the NPDES program in Florida. PEF's Anclote, Bartow, and Crystal River North, Crystal River South, and Suwannee NPDES permits were issued on January 19, 2011, February 14, 2011, July 21, 2011, March 9, 2012 and November 28, 2011 respectively. All facilities are required to meet new permitting conditions. In Docekt No. 110007-EI, the Commission approved recovery of costs associated with new requirements included or expected to be included in the new renewal permits, including: thermal studies, aquatic organism return studies and implementation, whole effluent toxicity testing, dissolved oxygen studies (Bartow only), and freeboard limitation related studies (Bartow only). As noted in PEF's February 8, 2012, program update, on December 14, 2011, FDEO issued a final NPDES renewal permit and associated Administrative Order for the Suwannee Plant. The Administrative Order includes a new requirement to

Project Accomplishments:
PEF has begun performing thermal studies, whole effluent toxicity testing, dissolved oxygen studies and freeboard limitation related studies and evaluations to comply with new permit requirements.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: O&M project variances for the 2012 were approximately $0.4 million due to reduced monitoring and cost, and regulatory delays.

Project Progress Summary:
PEF has begun complying with the requirements of the NPDES permits. Aquatic organism return study requirements have been postponed to align with the final EPA 316(b) rule requirements (Bartow/Anclote Plants). The aquatic organism return requirement is not a requirement in the Crystal River North plant NPDES permit.

Project Projections:
Estimated O&M and capital project expenditures for the period January 2013 through December 2013 are expected to be approximately $0.5 million in O&M costs and approximately $0.2 million in capital expenditures to ensure ongoing compliance with NPDES permits.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Integrated Clean Air Compliance Plan - Mercury & Air Toxic Standards (MATS) - Energy**
Project No. 17 **CR 4 & CR 5**

Project Description:
In Order No. PSC-11-0553-FOF-EI Docket No. 110007-EI dated 12/7/11, the Commission approved ECRC recovery of PEF's costs associated with emissions testing and related analysis necessary to develop PEF's strategy for achieving compliance with new hazardous air pollutant standards (now known as MATS) at Crystal River Units 4&5. The final Mercury and Air Toxics Rule (MATS) was issued by the EPA on 12/21/11. PEF will utilize the co-benefits of the existing FGD and SCR systems as the primary MATS compliance measure for CR4&5, but additional analyses are ongoing to determine whether more control measures will be necessary for those units.

Project Accomplishments:
PEF completed initial MATS emission testing at Crystal River Unit 4 in August 2011. PEF is conducting more detailed emissions testing to adequately assess potential mercury control strategies through the use of carbon traps that will allow continuous monitoring and trending of mercury emissions from these Units 4 and 5.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: PEF expects that total O&M project expenditure variance for the year will be approximately $0.3 million and capital investment variance of $0.1 million. This variance is primarily attributable to the change in strategy for Crystal River Units 4 and 5 as described in the May 14, 2012 program update (e.g., use of carbon traps rather than control optimization and testing, stack emissions testing, and varying unit operational parameters).

Project Progress Summary:
PEF completed initial MATS emission testing at Crystal River Unit 4 in August 2011. PEF is conducting more detailed emissions testing to adequately assess potential mercury control strategies through the use of carbon traps that will allow continuous monitoring and trending of mercury emissions from these Units 4 and 5.

Project Projections:
PEF expects to spend $10 million in capital in 2013. These costs are preliminary and PEF anticipates the installation and maintenance of continuous mercury emissions monitors on Crystal River Units 4 and 5. The costs and scope of work will be refined as PEF continues development of its compliance strategy.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2013 - DECEMBER 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Integrated Clean Air Compliance Plan - Mercury & Air Toxic Standards (MATS) - Energy**
Project No. 17.1 **Anclote Gas Conversion**

Project Description:
Convert existing Anclote Units to use 100% natural gas to be in compliance with Mercury and Air Toxics Standards (MATS) finaled by the EPA 12/16/11.

Project Accomplishments:
The project's major accomplishments to date are: finalized contract with OEM, finalized natural gas contract, and a draft air permit for public comment has been issued.

Project Fiscal Expenditures:
January 1, 2012 to December 31, 2012: PEF expects no O&M project expenditure variance for the year and capital investment variance of $22.2 million. This is a new project and therefore no projected spend amount was provided in Docket 110007-EI.

Project Progress Summary:
This project is on schedule with balance of plant engineering in progress and the development and insurance of the RFP for

Project Projections:
Estimated project expenditures for the period January 2013 through December 2013 are expected to be approximately $47.9 million.

PROGRESS ENERGY FLORIDA

Form 42-6P

Environmental Cost Recovery Clause (ECRC)

Calculation of the Energy & Demand Allocation % by Rate Class

JANUARY 2013 - DECEMBER 2013

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrsx(1))	(4) NCP Class Max Load Factor	(5) Delivery Efficiency Factor	(6) Sales at Source (Generation) (mWh) (2)/(5)	(7) Avg 12 CP at Source (MW) (3)/(5)	7(a) Sales at Source (Distrib Svc Only) (mWh)	(8) Class Max MW at Source Level (Distrib Svc) (7a)/(8760hrs/(4))	(9) mWh Sales at Source Energy Allocator (%)	(10) 12CP Demand Transmission Allocator (%)	(11) 12CP & 1/13 AD Demand Allocator (%)	(12) NCP Distribution Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	0.519	19,052,365	4,190.79	0.405	0.9406868	20,253,675	4,455.03	20,253,675	5,704.9	51.168%	61.694%	60.884%	61.181%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.652	1,231,321	215.55	0.452	0.9406868	1,308,960	229.14	1,308,960	330.8	3.307%	3.173%	3.183%	3.547%
Primary	0.652	3,357	0.59	0.452	0.9726000	3,452	0.60	3,452	0.9	0.009%	0.008%	0.008%	0.009%
Transmission	0.652	4,001	0.70	0.452	0.9826000	4,072	0.71	0	0.0	0.010%	0.010%	0.010%	0.000%
										3.326%	3.191%	3.202%	3.557%
General Service													
GS-2 Secondary	1.000	122,218	13.95	1.000	0.9406868	129,924	14.83	129,924	14.8	0.328%	0.205%	0.215%	0.159%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.774	12,089,141	1,782.97	0.611	0.9406868	12,851,399	1,895.39	12,851,399	2,399.9	32.467%	26.248%	26.726%	25.737%
Primary	0.774	2,335,710	344.48	0.611	0.9726000	2,401,511	354.19	2,401,511	448.5	6.067%	4.905%	4.994%	4.809%
Transm Del/ Primary Mtr	0.774	2,020	0.30	0.611	0.9726000	2,077	0.31	0	0.0	0.005%	0.004%	0.004%	0.000%
Transmission	0.774	0	0.00	0.611	0.9826000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.483	9	0.00	0.111	0.9726000	9	0.00	9	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.483	9,797	0.75	0.111	0.9826000	9,970	0.77	0	0.0	0.025%	0.011%	0.012%	0.000%
Transm Del/ Primary Mtr	1.483	2,571	0.20	0.111	0.9726000	2,643	0.20	0	0.0	0.007%	0.003%	0.003%	0.000%
										38.572%	31.170%	31.739%	30.546%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	1.186	0	0.00	0.465	0.9406868	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	1.186	87,952	8.46	0.465	0.9726000	90,430	8.70	90,430	22.2	0.228%	0.121%	0.129%	0.238%
SS-3 Primary	0.814	16,770	2.35	0.012	0.9726000	17,242	2.42	17,242	168.2	0.044%	0.033%	0.034%	1.804%
										0.272%	0.154%	0.163%	2.042%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.963	95,523	11.33	0.699	0.9406868	101,546	12.04	101,546	16.6	0.257%	0.167%	0.174%	0.178%
Sec Del/Primary Mtr	0.963	4,345	0.52	0.699	0.9726000	4,467	0.53	4,467	0.7	0.011%	0.007%	0.008%	0.008%
Primary Del / Primary Mtr	0.963	1,207,091	143.12	0.699	0.9726000	1,241,097	147.15	1,241,097	202.7	3.135%	2.038%	2.122%	2.173%
Primary Del / Transm Mtr	0.963	13,492	1.60	0.699	0.9826000	13,731	1.63	13,731	2.2	0.035%	0.023%	0.023%	0.024%
Transm Del/ Transm Mtr	0.963	297,859	35.32	0.699	0.9826000	303,134	35.94	0	0.0	0.766%	0.498%	0.518%	0.000%
Transm Del/ Primary Mtr	0.963	279,244	33.11	0.699	0.9726000	287,111	34.04	0	0.0	0.725%	0.471%	0.491%	0.000%
SS-2 Primary	0.859	13,454	1.79	0.331	0.9726000	13,833	1.84	13,833	4.8	0.035%	0.025%	0.026%	0.051%
Transm Del/ Transm Mtr	0.859	74,361	9.89	0.331	0.9826000	75,678	10.06	0	0.0	0.191%	0.139%	0.143%	0.000%
Transm Del/ Primary Mtr	0.859	59,627	7.93	0.331	0.9726000	61,307	8.15	0	0.0	0.155%	0.113%	0.116%	0.000%
										5.310%	3.481%	3.622%	2.434%
Lighting													
LS-1 (Secondary)	6.141	381,146	7.09	6.141	0.9406868	405,178	7.53	405,178	7.5	1.024%	0.104%	0.175%	0.081%
		37,383,374	6,812.77			39,582,447	7,221.21	38,836,455	9,324.6	100.000%	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2012
(2) Projected kWh sales for the period January 2013 to December 2013
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2009
(5) Based on system average line loss analysis for 2011
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,760 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class

January 2013 - December 2013

Form 42-7P - REVISED 10/18/12

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Demand Allocator (%)	(3) 12CP & 1/13th AD Demand Allocator (%)	(4) NCP Distribution Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	(11) Environmental Cost Recovery Factors (cents/kWh)
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1											
Secondary	51.168%	61.694%	60.884%	61.181%	$90,109,954	$622,165	$436,097	$2,877,593	$94,045,809	19,052,365	0.494
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,231,321	0.490
Primary										3,323	0.485
Transmission										3,921	0.480
TOTAL GS	3.326%	3.191%	3.202%	3.557%	$5,857,121	$32,185	$25,352	$151,328	$6,065,986	1,238,565	
General Service											
GS-2 Secondary	0.328%	0.205%	0.215%	0.159%	$578,042	$2,071	$1,134	$10,154	$591,401	122,218	0.484
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										12,089,141	0.485
Primary										2,314,907	0.480
Transmission										9,601	0.475
TOTAL GSD	38.572%	31.170%	31.739%	30.546%	$67,926,617	$314,342	$217,733	$1,500,116	$69,958,808	14,413,649	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	0.485
Primary										103,675	0.480
Transmission										-	0.475
TOTAL CS	0.272%	0.154%	0.163%	2.042%	$479,041	$1,553	$14,554	$7,706	$502,854	103,675	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										95,523	0.474
Primary										1,548,123	0.469
Transmission										377,998	0.465
TOTAL IS	5.310%	3.481%	3.622%	2.434%	$9,351,509	$35,107	$17,351	$171,183	$9,575,150	2,021,644	
Lighting											
LS-1 Secondary	1.024%	0.104%	0.175%	0.081%	$1,802,666	$1,052	$576	$8,272	$1,812,566	381,146	0.476
	100.000%	100.000%	100.000%	100.000%	$176,104,949	$1,008,475	$712,797	$4,726,353	$182,552,573	37,333,263	0.489

Notes:

(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 10
(3) From Form 42-6P, Column 11
(4) From Form 42-6P, Column 12
(5) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(6) Column 2 x Total Transmission Demand Jurisdictional Dollars from Form 42-1P, line 5
(7) Column 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 3 x Total Production Demand Jurisdictional Dollars from Form 42-1P, line 5
(9) Column 5 + Column 6 + Column 7 + Column 8
(10) Projected kWh sales at secondary voltage level for the period January 2013 to December 2013
(11) (Column 9/ Column 10)/10

PROGRESS ENERGY FLORIDA

Form 42-8P

Environmental Cost Recovery Clause (ECRC)

Calculation of the Current Period Estimated/Actual Amount

January 2013 through December 2013

Progress Energy Florida Capital Structure and Cost Rates

(In Thousands)

Class of Capital	Retail Amount	Ratio	Cost Rate	Weighted Cost Rate	Pretax Weighted Cost Rate
CE	$ 3,384,964	45.48%	0.10500	4.7800%	7.78%
PS	23,017	0.31%	0.04513	0.0100%	0.02%
LTD	3,010,543	40.45%	0.05730	2.3200%	2.32%
STD	20,229	0.27%	0.00650	0.0000%	0.00%
CD-Active	168,807	2.27%	0.06270	0.1400%	0.14%
CD-Inactive	882	0.01%	0.00000	0.0000%	0.00%
ADIT	976,720	13.12%	0.00000	0.0000%	0.00%
FAS 109	(145,373)	-1.95%	0.00000	0.0000%	0.00%
ITC- Debt	1,354	0.02%	0.04726	0.0000%	0.00%
ITC - Equity	1,533	0.02%	0.08630	0.0000%	0.00%
Total	$ 7,442,678	100.00%		7.25%	10.26%
			Total Debt	2.46%	2.46%
			Total Equity	4.79%	7.80%

Source: Per 13-Month Average Rate of Return - Capital Structure worksheet - - PEF's May 2012 Earning Surveillance Report

Rationale: The Company is using its May 2012 Earnings Surveillance Report in accordance with the 2012 WACC Stipulation & Settlement PAA Order No. PSC-12-0425-PAA-EU, August 16, 2012, in Docket Nos. 120001-EI, 120002-EI, 120007-EI.

Docket No. 120007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-3R)
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Witness: T.G. Foster
Exhibit_(TGF-4)

Progress Energy Florida, Inc.
Environmental Cost Recovery
Capital Program Detail

January 2013 - December 2013

Docket No. 120007-EI

FLORIDA PUBLIC SERVICE COMMISSION			
DOCKET NO.	120007-EI	**EXHIBIT**	31
PARTY	Progress Energy Florida		
DESCRIPTION	Thomas Foster (TGF-4) Capital Program Detail		
DATE	January 2013 through Dec. 2013		

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3	Less: Accumulated Depreciation		(7,441)	(7,495)	(7,549)	(7,603)	(7,657)	(7,711)	(7,765)	(7,819)	(7,873)	(7,927)	(7,981)	(8,035)	(8,089)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		26,512	26,458	26,404	26,350	26,296	26,242	26,188	26,134	26,080	26,026	25,972	25,918	25,864	
6	Average Net Investment			26,485	26,431	26,377	26,323	26,269	26,215	26,161	26,107	26,053	25,999	25,945	25,891	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		54	54	54	54	54	54	54	54	53	53	53	53	644
	b. Equity Component Grossed Up For Taxes	7.80%		172	172	171	171	171	170	170	170	169	169	169	168	2,042
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.90%		54	54	54	54	54	54	54	54	54	54	54	54	648
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009939		28	28	28	28	28	28	28	28	28	28	28	28	336
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			308	308	307	307	307	306	306	306	304	304	304	303	3,670
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			308	308	307	307	307	306	306	306	304	304	304	303	3,670

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	
3	Less: Accumulated Depreciation		(727,631)	(733,352)	(739,073)	(744,794)	(750,515)	(756,236)	(761,957)	(767,678)	(773,399)	(779,120)	(784,841)	(790,562)	(796,283)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,913,005	1,907,284	1,901,563	1,895,842	1,890,121	1,884,400	1,878,679	1,872,958	1,867,237	1,861,516	1,855,795	1,850,074	1,844,353	
6	Average Net Investment			1,910,145	1,904,424	1,898,703	1,892,982	1,887,261	1,881,540	1,875,819	1,870,098	1,864,377	1,858,656	1,852,935	1,847,214	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		3,916	3,904	3,892	3,881	3,869	3,857	3,845	3,834	3,822	3,810	3,799	3,787	46,216
	b. Equity Component Grossed Up For Taxes	7.80%		12,413	12,376	12,339	12,301	12,264	12,227	12,190	12,153	12,116	12,078	12,041	12,004	146,502
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	68,652
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009939		2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	26,244
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			24,237	24,188	24,139	24,090	24,041	23,992	23,943	23,895	23,846	23,796	23,748	23,699	287,614
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			24,237	24,188	24,139	24,090	24,041	23,992	23,943	23,895	23,846	23,796	23,748	23,699	287,614

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	
3	Less: Accumulated Depreciation		(109,012)	(110,982)	(112,952)	(114,922)	(116,892)	(118,862)	(120,832)	(122,802)	(124,772)	(126,742)	(128,712)	(130,682)	(132,652)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		800,394	798,424	796,454	794,484	792,514	790,544	788,574	786,604	784,634	782,664	780,694	778,724	776,754	
6	Average Net Investment			799,409	797,439	795,469	793,499	791,529	789,559	787,589	785,619	783,649	781,679	779,709	777,739	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		1,639	1,635	1,631	1,627	1,623	1,619	1,615	1,611	1,606	1,602	1,598	1,594	19,400
	b. Equity Component Grossed Up For Taxes	7.80%		5,195	5,182	5,169	5,157	5,144	5,131	5,118	5,105	5,092	5,080	5,067	5,054	61,494
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	23,640
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009939		753	753	753	753	753	753	753	753	753	753	753	753	9,036
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,557	9,540	9,523	9,507	9,490	9,473	9,456	9,439	9,421	9,405	9,388	9,371	113,570
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			9,557	9,540	9,523	9,507	9,490	9,473	9,456	9,439	9,421	9,405	9,388	9,371	113,570

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	135,074	
3	Less: Accumulated Depreciation		(4,788)	(5,171)	(5,554)	(5,937)	(6,320)	(6,703)	(7,086)	(7,469)	(7,852)	(8,235)	(8,618)	(9,001)	(9,384)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		130,286	129,903	129,520	129,137	128,754	128,371	127,988	127,605	127,222	126,839	126,456	126,073	125,690	
6	Average Net Investment			130,095	129,712	129,329	128,946	128,563	128,180	127,797	127,414	127,031	126,648	126,265	125,882	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		267	266	265	264	264	263	262	261	260	259	258	3,149	
	b. Equity Component Grossed Up For Taxes	7.80%		845	843	840	838	835	833	830	828	826	823	821	818	9,980
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.40%		383	383	383	383	383	383	383	383	383	383	383	383	4,596
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009939		112	112	112	112	112	112	112	112	112	112	112	112	1,344
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,607	1,604	1,600	1,597	1,594	1,591	1,587	1,584	1,581	1,578	1,575	1,571	19,069
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,607	1,604	1,600	1,597	1,594	1,591	1,587	1,584	1,581	1,578	1,575	1,571	19,069

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	
3	Less: Accumulated Depreciation		(219,555)	(224,678)	(229,801)	(234,924)	(240,047)	(245,170)	(250,293)	(255,416)	(260,539)	(265,662)	(270,785)	(275,908)	(281,031)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,847,044	1,841,921	1,836,798	1,831,675	1,826,552	1,821,429	1,816,306	1,811,183	1,806,060	1,800,937	1,795,814	1,790,691	1,785,568	
6	Average Net Investment			1,844,483	1,839,360	1,834,237	1,829,114	1,823,991	1,818,868	1,813,745	1,808,622	1,803,499	1,798,376	1,793,253	1,788,130	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		3,781	3,771	3,760	3,750	3,739	3,729	3,718	3,708	3,697	3,687	3,676	3,666	44,682
	b. Equity Component Grossed Up For Taxes	7.80%		11,988	11,953	11,920	11,886	11,853	11,820	11,787	11,753	11,720	11,687	11,653	11,620	141,638
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.98%		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.012430		2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	2,141	25,692
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			23,031	22,988	22,944	22,900	22,856	22,813	22,769	22,725	22,681	22,638	22,593	22,550	273,488
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			23,031	22,988	22,944	22,900	22,856	22,813	22,769	22,725	22,681	22,638	22,593	22,550	273,488

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,601	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	
3	Less: Accumulated Depreciation		(159,891)	(163,576)	(167,261)	(170,946)	(174,631)	(178,316)	(182,001)	(185,686)	(189,371)	(193,056)	(196,741)	(200,426)	(204,111)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,313,910	1,310,225	1,306,540	1,302,855	1,299,170	1,295,485	1,291,800	1,288,115	1,284,430	1,280,745	1,277,060	1,273,375	1,269,690	
6	Average Net Investment			1,312,068	1,308,383	1,304,698	1,301,013	1,297,328	1,293,643	1,289,958	1,286,273	1,282,588	1,278,903	1,275,218	1,271,533	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		2,690	2,682	2,675	2,667	2,660	2,652	2,644	2,637	2,629	2,622	2,614	2,607	31,779
	b. Equity Component Grossed Up For Taxes	7.80%		8,526	8,502	8,479	8,455	8,431	8,407	8,383	8,359	8,335	8,311	8,287	8,263	100,738
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	14,940
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			16,146	16,114	16,084	16,052	16,021	15,989	15,957	15,926	15,894	15,863	15,831	15,800	191,677
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			16,146	16,114	16,084	16,052	16,021	15,989	15,957	15,926	15,894	15,863	15,831	15,800	191,677

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,684	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation		(505,127)	(514,266)	(523,405)	(532,544)	(541,683)	(550,822)	(559,961)	(569,100)	(578,239)	(587,378)	(596,517)	(605,656)	(614,795)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,156,537	1,147,398	1,138,259	1,129,120	1,119,981	1,110,642	1,101,703	1,092,564	1,083,425	1,074,286	1,065,147	1,056,008	1,046,869	
6	Average Net Investment			1,151,968	1,142,829	1,133,690	1,124,551	1,115,412	1,106,273	1,097,134	1,087,995	1,078,856	1,069,717	1,060,578	1,051,439	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		2,362	2,343	2,324	2,305	2,287	2,266	2,249	2,230	2,212	2,193	2,174	2,155	27,102
	b. Equity Component Grossed Up For Taxes	7.80%		7,486	7,427	7,367	7,308	7,248	7,189	7,130	7,070	7,011	6,951	6,892	6,833	85,912
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.60%		9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008990		1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	14,940
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			20,232	20,154	20,075	19,997	19,919	19,841	19,763	19,684	19,607	19,528	19,450	19,372	237,622
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			20,232	20,154	20,075	19,997	19,919	19,841	19,763	19,684	19,607	19,528	19,450	19,372	237,622

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	
3	Less: Accumulated Depreciation		(46,937)	(47,653)	(48,369)	(49,085)	(49,801)	(50,517)	(51,233)	(51,949)	(52,665)	(53,381)	(54,097)	(54,813)	(55,529)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		132,001	131,285	130,569	129,853	129,137	128,421	127,705	126,989	126,273	125,557	124,841	124,125	123,409	
6	Average Net Investment			131,643	130,927	130,211	129,495	128,779	128,063	127,347	126,631	125,915	125,199	124,483	123,767	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		270	268	267	265	264	263	261	260	258	257	255	254	3,142
	b. Equity Component Grossed Up For Taxes	7.80%		855	851	846	842	837	832	828	823	818	814	809	804	9,959
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.80%		716	716	716	716	716	716	716	716	716	716	716	716	8,592
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930		148	148	148	148	148	148	148	148	148	148	148	148	1,776
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,989	1,983	1,977	1,971	1,965	1,959	1,953	1,947	1,940	1,935	1,928	1,922	23,469
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,989	1,983	1,977	1,971	1,965	1,959	1,953	1,947	1,940	1,935	1,928	1,922	23,469

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2013 through December 2013
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3	Less: Accumulated Depreciation		(111,332)	(113,156)	(114,984)	(116,810)	(118,636)	(120,462)	(122,288)	(124,114)	(125,940)	(127,768)	(129,592)	(131,418)	(133,244)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		618,963	617,137	615,311	613,485	611,659	609,833	606,007	606,181	604,355	602,529	600,703	598,877	597,051	
6	Average Net Investment			618,050	616,224	614,398	612,572	610,746	608,920	607,094	605,268	603,442	601,616	599,790	597,964	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		1,267	1,263	1,260	1,256	1,252	1,248	1,245	1,241	1,237	1,233	1,230	1,226	14,958
	b. Equity Component Grossed Up For Taxes	7.80%		4,016	4,004	3,993	3,981	3,969	3,957	3,945	3,933	3,921	3,910	3,898	3,886	47,413
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	21,912
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		617	617	617	617	617	617	617	617	617	617	617	617	7,404
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			7,726	7,710	7,696	7,680	7,664	7,648	7,633	7,617	7,601	7,586	7,571	7,555	91,687
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			7,726	7,710	7,696	7,680	7,664	7,648	7,633	7,617	7,601	7,586	7,571	7,555	91,687

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(187,032)	(189,884)	(192,736)	(195,588)	(198,440)	(201,292)	(204,144)	(206,996)	(209,848)	(212,700)	(215,552)	(218,404)	(221,256)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		850,167	847,315	844,463	841,611	838,759	835,907	833,055	830,203	827,351	824,499	821,647	818,795	815,943	
6	Average Net Investment			848,741	845,889	843,037	840,185	837,333	834,481	831,629	828,777	825,925	823,073	820,221	817,369	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		1,740	1,734	1,728	1,722	1,717	1,711	1,705	1,699	1,693	1,687	1,681	1,676	20,493
	b. Equity Component Grossed Up For Taxes	7.80%		5,515	5,497	5,478	5,460	5,441	5,423	5,404	5,386	5,367	5,349	5,330	5,312	64,962
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.30%		2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008590		742	742	742	742	742	742	742	742	742	742	742	742	8,904
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,849	10,825	10,600	10,776	10,752	10,726	10,703	10,679	10,654	10,630	10,605	10,582	128,583
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			10,849	10,825	10,800	10,776	10,752	10,728	10,703	10,679	10,654	10,630	10,605	10,582	128,583

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2013 through December 2013
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	
3	Less: Accumulated Depreciation		(257,870)	(265,707)	(273,544)	(281,381)	(289,218)	(297,055)	(304,892)	(312,729)	(320,566)	(328,403)	(336,240)	(344,077)	(351,914)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		3,359,034	3,351,197	3,343,360	3,335,523	3,327,686	3,319,849	3,312,012	3,304,175	3,296,338	3,288,501	3,280,664	3,272,827	3,264,990	
6	Average Net Investment			3,355,115	3,347,278	3,339,441	3,331,604	3,323,767	3,315,930	3,308,093	3,300,256	3,292,419	3,284,582	3,276,745	3,268,908	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		6,878	6,862	6,846	6,830	6,814	6,798	6,782	6,766	6,749	6,733	6,717	6,701	81,476
	b. Equity Component Grossed Up For Taxes	7.80%		21,803	21,752	21,701	21,650	21,599	21,548	21,497	21,447	21,396	21,345	21,294	21,243	258,275
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	94,044
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.012430		3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	44,964
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			40,265	40,196	40,131	40,064	39,997	39,930	39,863	39,797	39,729	39,662	39,595	39,528	478,759
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			40,265	40,198	40,131	40,064	39,997	39,930	39,863	39,797	39,729	39,662	39,595	39,528	478,759

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation		(45,822)	(48,058)	(46,294)	(46,530)	(46,766)	(47,002)	(47,238)	(47,474)	(47,710)	(47,946)	(48,182)	(48,418)	(48,654)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		95,612	95,376	95,140	94,904	94,668	94,432	94,196	93,960	93,724	93,488	93,252	93,016	92,780	
6	Average Net Investment			95,494	95,258	95,022	94,786	94,550	94,314	94,078	93,842	93,606	93,370	93,134	92,898	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		196	195	195	194	194	193	193	192	192	191	191	190	2,316
	b. Equity Component Grossed Up For Taxes	7.80%		621	619	617	618	614	613	611	610	608	607	605	604	7,345
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.00%		236	236	236	238	236	236	236	236	236	236	236	236	2,832
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.014450		170	170	170	170	170	170	170	170	170	170	170	170	2,040
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,223	1,220	1,218	1,216	1,214	1,212	1,210	1,208	1,206	1,204	1,202	1,200	14,533
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,223	1,220	1,218	1,216	1,214	1,212	1,210	1,208	1,206	1,204	1,202	1,200	14,533

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	
3	Less: Accumulated Depreciation		(76,768)	(77,545)	(79,322)	(81,099)	(82,876)	(84,653)	(86,430)	(88,207)	(89,984)	(91,761)	(93,538)	(95,315)	(97,092)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		319,200	317,423	315,646	313,869	312,092	310,315	308,538	306,761	304,984	303,207	301,430	299,653	297,876	
6	Average Net Investment			318,311	316,534	314,757	312,980	311,203	309,426	307,649	305,872	304,095	302,318	300,541	298,764	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		653	649	645	642	638	634	631	627	623	620	616	612	7,590
	b. Equity Component Grossed Up For Taxes	7.80%		2,069	2,057	2,045	2,034	2,022	2,011	1,999	1,988	1,976	1,965	1,953	1,941	24,060
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.40%		1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	21,324
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		334	334	334	334	334	334	334	334	334	334	334	334	4,008
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,833	4,817	4,801	4,787	4,771	4,756	4,741	4,726	4,710	4,696	4,680	4,664	56,982
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,833	4,817	4,801	4,787	4,771	4,756	4,741	4,726	4,710	4,696	4,680	4,664	56,982

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation		(12,219)	(12,321)	(12,423)	(12,525)	(12,627)	(12,729)	(12,831)	(12,933)	(13,035)	(13,137)	(13,239)	(13,341)	(13,443)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		20,873	20,771	20,669	20,567	20,465	20,363	20,261	20,159	20,057	19,955	19,853	19,751	19,649	
6	Average Net Investment			20,822	20,720	20,618	20,516	20,414	20,312	20,210	20,108	20,006	19,904	19,802	19,700	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		43	42	42	42	42	42	41	41	41	41	41	40	498
	b. Equity Component Grossed Up For Taxes	7.80%		135	135	134	133	133	132	131	131	130	129	129	128	1,580
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.70%		102	102	102	102	102	102	102	102	102	102	102	102	1,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		22	22	22	22	22	22	22	22	22	22	22	22	264
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			302	301	300	299	299	298	296	296	295	294	294	292	3,566
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			302	301	300	299	299	298	296	296	295	294	294	292	3,566

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	
3	Less: Accumulated Depreciation		(276,191)	(282,135)	(288,079)	(294,023)	(299,967)	(305,911)	(311,855)	(317,799)	(323,743)	(329,687)	(335,631)	(341,575)	(347,519)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		2,576,988	2,571,044	2,565,100	2,559,156	2,553,212	2,547,268	2,541,324	2,535,380	2,529,436	2,523,492	2,517,548	2,511,604	2,505,660	
6	Average Net Investment			2,574,016	2,568,072	2,562,128	2,556,184	2,550,240	2,544,296	2,538,352	2,532,406	2,526,464	2,520,520	2,514,576	2,508,632	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		5,277	5,265	5,252	5,240	5,228	5,216	5,204	5,191	5,179	5,167	5,155	5,143	62,517
	b. Equity Component Grossed Up For Taxes	7.80%		16,727	16,688	16,650	16,611	16,573	16,534	16,495	16,457	16,418	16,379	16,341	16,302	198,175
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	71,328
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		1,874	1,874	1,874	1,874	1,874	1,874	1,874	1,674	1,874	1,874	1,874	1,874	22,488
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			29,822	29,771	29,720	29,689	29,819	29,568	29,517	29,466	29,415	29,364	29,314	29,263	354,508
	e. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			29,822	29,771	29,720	29,669	29,619	29,568	29,517	29,466	29,415	29,364	29,314	29,263	354,508

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(41,370)	(41,902)	(42,434)	(42,966)	(43,498)	(44,030)	(44,562)	(45,094)	(45,626)	(46,158)	(46,690)	(47,222)	(47,754)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		248,928	248,396	247,864	247,332	246,800	246,268	245,736	245,204	244,672	244,140	243,608	243,076	242,544	
6	Average Net Investment			248,662	248,130	247,598	247,066	246,534	246,002	245,470	244,938	244,406	243,874	243,342	242,810	
7	Return on Averege Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		510	509	508	506	505	504	503	502	501	500	499	498	6,045
	b. Equity Component Grossed Up For Taxes	7.80%		1,616	1,612	1,609	1,606	1,602	1,599	1,595	1,592	1,588	1,585	1,581	1,578	19,163
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.20%		532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008310		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,859	2,854	2,850	2,845	2,840	2,836	2,831	2,827	2,822	2,818	2,813	2,809	34,004
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,859	2,854	2,850	2,845	2,840	2,836	2,831	2,827	2,822	2,818	2,813	2,809	34,004

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3	Less: Accumulated Depreciation		(19,097)	(19,501)	(19,905)	(20,309)	(20,713)	(21,117)	(21,521)	(21,925)	(22,329)	(22,733)	(23,137)	(23,541)	(23,945)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		142,657	142,253	141,849	141,445	141,041	140,637	140,233	139,829	139,425	139,021	138,617	138,213	137,809	
6	Average Net Investment			142,455	142,051	141,647	141,243	140,839	140,435	140,031	139,627	139,223	138,819	138,415	138,011	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.48% x 1/12)	2.46%		292	291	290	290	289	288	287	286	285	285	284	283	3,450
	b. Equity Component Grossed Up For Taxes	7.80%		926	923	920	918	915	913	910	907	905	902	899	897	10,935
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		404	404	404	404	404	404	404	404	404	404	404	404	4,848
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930		134	134	134	134	134	134	134	134	134	134	134	134	1,608
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,756	1,752	1,746	1,746	1,742	1,739	1,735	1,731	1,728	1,725	1,721	1,716	20,841
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,756	1,752	1,746	1,746	1,742	1,739	1,735	1,731	1,728	1,725	1,721	1,716	20,841

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3	Less: Accumulated Depreciation		(32,485)	(32,852)	(33,219)	(33,586)	(33,953)	(34,320)	(34,687)	(35,054)	(35,421)	(35,788)	(36,155)	(36,522)	(36,889)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		242,862	242,495	242,128	241,761	241,394	241,027	240,660	240,293	239,926	239,559	239,192	238,825	238,458	
6	Average Net Investment			242,679	242,312	241,945	241,578	241,211	240,844	240,477	240,110	239,743	239,378	239,009	238,642	
7	Return on Averege Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		497	497	496	495	494	494	493	492	491	491	490	489	5,919
	b. Equity Component Grossed Up For Taxes	7.80%		1,577	1,575	1,572	1,570	1,567	1,565	1,563	1,560	1,558	1,556	1,553	1,551	18,767
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.60%		367	367	367	367	367	367	367	367	367	367	367	367	4,404
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		233	233	233	233	233	233	233	233	233	233	233	233	2,796
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,674	2,672	2,668	2,665	2,661	2,659	2,656	2,652	2,649	2,647	2,643	2,640	31,886
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,674	2,672	2,668	2,665	2,661	2,659	2,656	2,652	2,649	2,647	2,643	2,640	31,886

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation		(24,795)	(25,176)	(25,557)	(25,938)	(26,319)	(26,700)	(27,081)	(27,462)	(27,843)	(28,224)	(28,605)	(28,986)	(29,367)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		174,193	173,812	173,431	173,050	172,669	172,288	171,907	171,526	171,145	170,764	170,383	170,002	169,621	
6	Average Net Investment			174,003	173,622	173,241	172,860	172,479	172,098	171,717	171,336	170,955	170,574	170,193	169,812	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		357	356	355	354	354	353	352	351	350	350	349	348	4,229
	b. Equity Component Grossed Up For Taxes	7.80%		1,131	1,128	1,126	1,123	1,121	1,118	1,116	1,113	1,111	1,108	1,106	1,104	13,405
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.30%		381	381	381	381	381	381	381	381	381	381	381	381	4,572
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		166	168	168	168	168	168	168	168	168	168	168	168	2,016
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,037	2,033	2,030	2,026	2,024	2,020	2,017	2,013	2,010	2,007	2,004	2,001	24,222
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,037	2,033	2,030	2,026	2,024	2,020	2,017	2,013	2,010	2,007	2,004	2,001	24,222

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation		(14,259)	(14,478)	(14,697)	(14,916)	(15,135)	(15,354)	(15,573)	(15,792)	(16,011)	(16,230)	(16,449)	(16,668)	(16,887)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		73,408	73,189	72,970	72,751	72,532	72,313	72,094	71,875	71,656	71,437	71,218	70,999	70,780	
6	Average Net Investment			73,298	73,079	72,860	72,641	72,422	72,203	71,984	71,765	71,546	71,327	71,108	70,889	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		150	150	149	149	148	148	148	147	147	146	146	145	1,773
	b. Equity Component Grossed Up For Taxes	7.80%		476	475	473	472	471	469	466	466	465	464	462	461	5,622
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismentlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.012430		91	91	91	91	91	91	91	91	91	91	91	91	1,092
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			936	935	932	931	929	927	926	923	922	920	918	916	11,115
	e. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			936	935	932	931	929	927	926	923	922	920	918	916	11,115

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	
3	Less: Accumulated Depreciation		(36,837)	(37,676)	(38,515)	(39,354)	(40,193)	(41,032)	(41,871)	(42,710)	(43,549)	(44,388)	(45,227)	(46,066)	(46,905)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		310,361	309,522	308,683	307,844	307,005	306,166	305,327	304,488	303,649	302,810	301,971	301,132	300,293	
6	Average Net Investment			309,941	309,102	308,263	307,424	306,585	305,746	304,907	304,068	303,229	302,390	301,551	300,712	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		635	634	632	630	628	627	625	623	622	620	618	616	7,510
	b. Equity Component Grossed Up For Taxes	7.80%		2,014	2,009	2,003	1,998	1,992	1,987	1,981	1,976	1,971	1,965	1,960	1,954	23,810
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.90%		839	839	839	839	839	839	839	839	839	839	839	839	10,068
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010140		293	293	293	293	293	293	293	293	293	293	293	293	3,516
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,761	3,775	3,767	3,760	3,752	3,746	3,738	3,731	3,725	3,717	3,710	3,702	44,904
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,761	3,775	3,767	3,760	3,752	3,746	3,738	3,731	3,725	3,717	3,710	3,702	44,904

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation		(47,791)	(48,578)	(49,365)	(50,152)	(50,939)	(51,726)	(52,513)	(53,300)	(54,087)	(54,874)	(55,661)	(56,448)	(57,235)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		301,793	301,006	300,219	299,432	298,645	297,858	297,071	296,284	295,497	294,710	293,923	293,136	292,349	
6	Average Net Investment			301,399	300,612	299,825	299,038	298,251	297,464	296,677	295,890	295,103	294,316	293,529	292,742	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		616	616	615	613	611	610	608	607	605	603	602	600	7,306
	b. Equity Component Grossed Up For Taxes	7.80%		1,959	1,954	1,948	1,943	1,938	1,933	1,928	1,923	1,918	1,913	1,907	1,902	23,166
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.70%		787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.006990		262	262	262	262	262	262	262	262	262	262	262	262	3,144
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,626	3,619	3,612	3,605	3,598	3,592	3,585	3,579	3,572	3,565	3,558	3,551	43,062
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,626	3,619	3,612	3,605	3,598	3,592	3,585	3,579	3,572	3,565	3,558	3,551	43,062

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3	Less: Accumulated Depreciation		(12,591)	(12,725)	(12,859)	(12,993)	(13,127)	(13,261)	(13,395)	(13,529)	(13,663)	(13,797)	(13,931)	(14,065)	(14,199)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		121,421	121,287	121,153	121,019	120,885	120,751	120,617	120,483	120,349	120,215	120,081	119,947	119,813	
6	Average Net Investment			121,354	121,220	121,086	120,952	120,818	120,684	120,550	120,416	120,282	120,148	120,014	119,880	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		249	249	248	248	248	247	247	247	247	246	246	246	2,968
	b. Equity Component Grossed Up For Taxes	7.80%		789	788	787	786	785	784	783	783	782	781	780	779	9,407
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.20%		134	134	134	134	134	134	134	134	134	134	134	134	1,608
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.012430		139	139	139	139	139	139	139	139	139	139	139	139	1,668
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,311	1,310	1,308	1,307	1,306	1,304	1,303	1,303	1,302	1,300	1,299	1,298	15,651
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,311	1,310	1,308	1,307	1,306	1,304	1,303	1,303	1,302	1,300	1,299	1,298	15,651

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation		(30,690)	(31,103)	(31,516)	(31,929)	(32,342)	(32,755)	(33,168)	(33,581)	(33,994)	(34,407)	(34,820)	(35,233)	(35,646)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		350,870	350,457	350,044	349,631	349,218	348,805	348,392	347,979	347,566	347,153	346,740	346,327	345,914	
6	Average Net Investment			350,663	350,250	349,837	349,424	349,011	348,598	348,185	347,772	347,359	346,946	346,533	346,120	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		719	716	717	716	715	715	714	713	712	711	710	710	8,570
	b. Equity Component Grossed Up For Taxes	7.80%		2,279	2,276	2,273	2,271	2,268	2,265	2,263	2,260	2,257	2,255	2,252	2,249	27,168
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.30%		413	413	413	413	413	413	413	413	413	413	413	413	4,956
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008590		273	273	273	273	273	273	273	273	273	273	273	273	3,276
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,684	3,680	3,676	3,673	3,669	3,666	3,663	3,659	3,655	3,652	3,648	3,645	43,970
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,684	3,680	3,676	3,673	3,669	3,666	3,663	3,659	3,655	3,652	3,648	3,645	43,970

For Project: CAIR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	18,065,027	
3	Less: Accumulated Depreciation		(1,599,883)	(1,622,464)	(1,645,045)	(1,667,626)	(1,690,207)	(1,712,788)	(1,735,369)	(1,757,950)	(1,780,531)	(1,803,112)	(1,825,693)	(1,848,274)	(1,870,855)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		16,465,144	18,442,563	16,419,982	16,397,401	16,374,820	16,352,239	16,329,658	16,307,077	16,284,496	16,261,915	16,239,334	16,216,753	16,194,172	
6	Average Net Investment			16,453,854	16,431,273	16,408,692	16,386,111	16,363,530	16,340,949	16,318,368	16,295,787	16,273,206	16,250,625	16,228,044	16,205,463	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	**2.95%** (Note 1)		40,482	40,426	40,371	40,315	40,259	40,204	40,148	40,093	40,037	39,982	39,926	39,871	482,114
	b. Equity Component Grossed Up For Taxes	**8.02%** (Note 1)		110,013	109,862	109,711	109,561	109,410	109,259	109,108	108,957	108,806	108,655	108,504	108,353	1,310,199
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	**1.50%**		22,581	22,581	22,581	22,581	22,581	22,581	22,581	22,581	22,581	22,581	22,581	22,581	270,972
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	**0.007680**		11,863	11,863	11,863	11,863	11,863	11,863	11,863	11,863	11,863	11,863	11,863	11,863	142,356
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			184,939	184,732	184,526	184,320	184,113	183,907	183,700	183,494	183,287	183,081	182,874	182,668	2,205,641
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			184,939	184,732	184,526	184,320	184,113	183,907	183,700	183,494	183,287	183,081	182,874	182,668	2,205,641

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

For Project: CAIR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	
3	Less: Accumulated Depreciation		(1,165,757)	(1,191,537)	(1,217,317)	(1,243,097)	(1,268,877)	(1,294,657)	(1,320,437)	(1,346,217)	(1,371,997)	(1,397,777)	(1,423,557)	(1,449,337)	(1,475,117)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		11,208,626	11,182,846	11,157,066	11,131,286	11,105,506	11,079,726	11,053,946	11,028,166	11,002,386	10,976,606	10,950,826	10,925,046	10,899,266	
6	Average Net Investment			11,195,736	11,169,956	11,144,176	11,118,396	11,092,616	11,066,836	11,041,056	11,015,276	10,989,496	10,963,716	10,937,936	10,912,156	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	**2.95%** (Note 1)		27,545	27,482	27,418	27,355	27,291	27,226	27,184	27,101	27,038	26,974	26,911	26,847	326,354
	b. Equity Component Grossed Up For Taxes	**8.02%** (Note 1)		74,857	74,684	74,512	74,340	74,167	73,995	73,822	73,650	73,478	73,305	73,133	72,961	886,904
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	**2.50%**		25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	309,360
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	**0.007680**		8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	8,126	97,512
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			136,308	136,072	135,836	135,601	135,364	135,129	134,892	134,657	134,422	134,185	133,950	133,714	1,620,130
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			136,308	135,072	135,836	135,601	135,364	135,129	134,892	134,657	134,422	134,185	133,950	133,714	1,620,130

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

For Project: CAIR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	96,642,017	
3	Less: Accumulated Depreciation		(8,460,987)	(8,659,908)	(8,858,829)	(9,057,750)	(9,256,671)	(9,455,592)	(9,654,513)	(9,853,434)	(10,052,355)	(10,251,276)	(10,450,197)	(10,649,118)	(10,846,039)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		88,181,030	87,982,109	87,783,188	87,584,267	87,385,346	87,186,425	86,987,504	86,788,583	86,589,662	86,390,741	86,191,820	85,992,899	85,793,978	
6	Average Net Investment			88,081,569	87,882,648	87,683,727	87,484,806	87,285,885	87,086,964	86,888,043	86,689,122	86,490,201	86,291,280	86,092,359	85,893,438	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.86% x 1/12)	**2.86%** (Note 1)		216,708	216,219	215,729	215,240	214,751	214,261	213,772	213,282	212,793	212,304	211,814	211,325	2,566,198
	b. Equity Component Grossed Up For Taxes	**8.02%** (Note 1)		588,929	587,599	586,269	584,938	583,609	582,279	580,949	579,619	578,289	576,959	575,629	574,299	6,979,368
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.47%	(Note 2)	198,921	198,921	198,921	198,921	198,921	198,921	198,921	198,921	198,921	198,921	198,921	198,921	2,387,052
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007680		63,462	63,462	63,462	63,462	63,462	63,462	63,462	63,462	63,462	63,462	63,462	63,462	761,544
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,066,020	1,066,201	1,064,381	1,062,562	1,060,743	1,058,923	1,057,104	1,055,284	1,053,465	1,051,646	1,049,826	1,048,007	12,696,162
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,066,020	1,066,201	1,064,381	1,062,562	1,060,743	1,058,923	1,057,104	1,055,284	1,053,465	1,051,646	1,049,826	1,048,007	12,696,162

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Note 2: The depreciation rate for project 7.4C is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result the blended rate shown above is based on approximately 98% of the investment in FERC account 312 at an approved depreciation rate of 2.50% and 2% of the investment in FERC account 315 at an approved depreciation rate of 1.0%.

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	626,073,323	
3	Less: Accumulated Depreciation		(45,235,834)	(46,336,480)	(47,437,326)	(48,538,172)	(49,639,018)	(50,739,864)	(51,840,710)	(52,941,556)	(54,042,402)	(55,143,248)	(56,244,094)	(57,344,940)	(58,445,786)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		580,837,489	579,736,843	578,635,997	577,535,151	576,434,305	575,333,459	574,232,613	573,131,767	572,030,921	570,930,075	569,829,229	568,728,383	567,627,537	
6	Average Net Investment			580,287,266	579,186,420	578,085,574	576,984,728	575,883,882	574,783,036	573,682,190	572,581,344	571,480,498	570,379,652	569,278,806	568,177,960	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	**2.95%** (Note 1)		1,427,688	1,424,980	1,422,271	1,419,563	1,416,854	1,414,146	1,411,437	1,408,729	1,406,021	1,403,312	1,400,604	1,397,895	16,953,500
	b. Equity Component Grossed Up For Taxes	**8.02%** (Note 1)		3,879,906	3,872,545	3,865,185	3,857,824	3,850,464	3,843,103	3,835,743	3,828,383	3,821,022	3,813,662	3,806,301	3,798,941	46,073,079
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.11% (Note 2)		1,100,846	1,100,846	1,100,846	1,100,846	1,100,846	1,100,846	1,100,846	1,100,846	1,100,846	1,100,846	1,100,846	1,100,846	13,210,152
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007680		411,121	411,121	411,121	411,121	411,121	411,121	411,121	411,121	411,121	411,121	411,121	411,121	4,933,452
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			6,819,561	6,809,492	6,799,423	6,789,354	6,779,285	6,769,216	6,759,147	6,749,079	6,739,010	6,728,941	6,718,872	6,708,803	81,170,183
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			6,819,561	6,809,492	6,799,423	6,789,354	6,779,285	6,769,216	6,759,147	6,749,079	6,739,010	6,728,941	6,718,872	6,708,803	81,170,183

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Note 2: The Depr. rate for 2013 is based on approximately 66% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, approximately 20% of the investment in FERC account 311 at an approved depreciation rate of 1.5%, approximately 12% of the investment in FERC account 315 at an approved depreciation rate of 1.0% and approximately 2% of the investment in FERC account 316 at an approved depreciation rate of 2.10%.

For Project: CAIR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	
3	Less: Accumulated Depreciation	(Note 3)	(5,323,105)	(5,445,116)	(5,567,127)	(5,689,138)	(5,811,149)	(5,933,160)	(6,055,171)	(6,177,182)	(6,299,193)	(6,421,204)	(6,543,215)	(6,665,226)	(6,787,237)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		55,937,597	55,815,586	55,693,575	55,571,564	55,449,553	55,327,542	55,205,531	55,083,520	54,961,509	54,839,498	54,717,487	54,595,476	54,473,465	
6	Average Net Investment			55,876,592	55,754,581	55,632,570	55,510,559	55,388,548	55,266,537	55,144,526	55,022,515	54,900,504	54,778,493	54,656,482	54,534,471	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		137,474	137,174	136,874	136,573	136,273	135,973	135,673	135,373	135,072	134,772	134,472	134,172	1,829,875
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		373,601	372,785	371,969	371,154	370,338	369,522	368,706	367,890	367,075	366,259	365,443	364,627	4,429,369
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.39% (Note 2)		122,011	122,011	122,011	122,011	122,011	122,011	122,011	122,011	122,011	122,011	122,011	122,011	1,464,132
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	40,228	482,736
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			673,314	672,198	671,082	669,966	668,850	667,734	666,618	665,502	664,386	663,270	662,154	661,038	8,006,112
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			673,314	672,198	671,082	669,966	668,850	667,734	666,618	665,502	664,386	663,270	662,154	661,038	8,006,112

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Note 2: The Depr. rate for 2013 is based on approximately 90% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, approximately 8% of the investment in FERC account 311 at an approved depreciation rate of 1.5%, and approximately 2% of the investment in FERC account 315 at an approved depreciation rate of 1.0%.

Note 3: Beginning Balance differs from CPD ending balance in the 2012 Estimated / Actual filing in Exhibit_(TGF-2) due to a correction to the depreciation expense. PEF has placed a credit in Line 1. Project 7.4 (January 2013) in schedule 42 3P in Exhibit_(TGF-3) to adjust for this revenue requirement.

For Project: CAIR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	129,727,926	
3	Less: Accumulated Depreciation		(9,903,206)	(10,161,581)	(10,419,956)	(10,678,331)	(10,936,706)	(11,195,081)	(11,453,456)	(11,711,831)	(11,970,206)	(12,228,581)	(12,486,956)	(12,745,331)	(13,003,706)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		119,824,720	119,566,345	119,307,970	119,049,595	118,791,220	118,532,845	118,274,470	118,016,095	117,757,720	117,499,345	117,240,970	116,982,595	116,724,220	
6	Average Net Investment			119,695,533	119,437,158	119,178,783	118,920,408	118,662,033	118,403,658	118,145,283	117,886,908	117,628,533	117,370,158	117,111,783	116,853,408	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		294,488	293,853	293,217	292,581	291,946	291,310	290,674	290,039	289,403	288,767	288,132	287,496	3,491,906
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		800,306	796,578	796,851	795,123	793,396	791,668	789,941	788,213	786,486	784,758	783,031	781,303	9,489,654
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.39% (Note 2)		258,375	258,375	258,375	258,375	258,375	258,375	258,375	258,375	258,375	258,375	258,375	258,375	3,100,500
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		85,188	85,188	85,188	85,188	85,188	85,188	85,188	85,188	85,188	85,188	85,188	85,188	1,022,256
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,438,357	1,435,994	1,433,631	1,431,267	1,428,905	1,426,541	1,424,178	1,421,815	1,419,452	1,417,088	1,414,726	1,412,362	17,104,316
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,438,357	1,435,994	1,433,631	1,431,267	1,428,905	1,426,541	1,424,178	1,421,815	1,419,452	1,417,088	1,414,726	1,412,362	17,104,316

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Note 2: The depreciation rate for project 7.4F is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result the blended rate shown above is based on approximately 92.5% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, 7.5% of the investment in FERC account 315 at an approved depreciation rate of 1.0%.

For Project: CAIR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing Controls (Project 7.4g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	
3	Less: Accumulated Depreciation		(56,147)	(57,918)	(59,689)	(61,460)	(63,231)	(65,002)	(66,773)	(68,544)	(70,315)	(72,086)	(73,857)	(75,628)	(77,399)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		794,051	792,280	790,509	788,738	786,967	785,196	783,425	781,654	779,883	778,112	776,341	774,570	772,799	
6	Average Net Investment			793,165	791,394	789,623	787,852	786,081	784,310	782,539	780,768	778,997	777,226	775,455	773,684	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		1,951	1,947	1,943	1,938	1,934	1,930	1,925	1,921	1,917	1,912	1,908	1,904	23,130
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		5,303	5,291	5,280	5,268	5,256	5,244	5,232	5,220	5,209	5,197	5,185	5,173	62,858
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	21,252
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		558	558	558	558	558	558	558	558	558	558	558	558	6,696
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,583	9,567	9,552	9,535	9,519	9,503	9,486	9,470	9,455	9,438	9,422	9,406	113,936
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			9,583	9,567	9,552	9,535	9,519	9,503	9,486	9,470	9,455	9,438	9,422	9,406	113,936

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

For Project: CAIR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing Controls (Project 7.4h)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	
3	Less: Accumulated Depreciation		(56,271)	(58,182)	(60,093)	(62,004)	(63,915)	(65,826)	(67,737)	(69,648)	(71,559)	(73,470)	(75,381)	(77,292)	(79,203)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		861,127	859,216	857,305	855,394	853,483	851,572	849,661	847,750	845,839	843,928	842,017	840,106	838,195	
6	Average Net Investment			860,171	858,260	856,349	854,438	852,527	850,616	848,705	846,794	844,883	842,972	841,061	839,150	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		2,116	2,112	2,107	2,102	2,097	2,093	2,088	2,083	2,079	2,074	2,069	2,065	25,085
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		5,751	5,738	5,726	5,713	5,700	5,687	5,675	5,662	5,649	5,636	5,623	5,611	68,171
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	22,932
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		602	602	602	602	602	602	602	602	602	602	602	602	7,224
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,380	10,363	10,346	10,328	10,310	10,293	10,276	10,258	10,241	10,223	10,205	10,189	123,412
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			10,380	10,363	10,346	10,328	10,310	10,293	10,276	10,258	10,241	10,223	10,205	10,189	123,412

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

For Project: CAIR Crystal River AFUDC - CR4 SCR (Project 7.4i)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	700,000	406,568	0	0	0	0	0	0	0	0	0	1,106,568
	b. Clearings to Plant			0	0	1,906,568	0	0	0	0	0	0	0	0	0	
	c. Retirements			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	
2	Plant-in-Service/Depreciation Base		108,798,396	108,798,396	108,798,396	110,704,964	110,704,964	110,704,964	110,704,964	110,704,964	110,704,964	110,704,964	110,704,964	110,704,964	110,704,964	
3	Less: Accumulated Depreciation		(7,053,046)	(7,276,969)	(7,500,932)	(7,726,837)	(7,954,705)	(8,182,573)	(8,410,441)	(8,638,309)	(8,866,177)	(9,094,045)	(9,321,913)	(9,549,781)	(9,777,649)	
4	CWIP - Non-Interest Bearing		800,000	800,000	1,500,000	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		102,545,350	102,321,407	102,797,464	102,978,127	102,750,259	102,522,391	102,294,523	102,066,655	101,838,787	101,610,919	101,383,051	101,155,183	100,927,315	
6	Average Net Investment			102,433,379	102,559,436	102,887,796	102,864,193	102,636,325	102,408,457	102,180,589	101,952,721	101,724,853	101,496,985	101,269,117	101,041,249	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		252,018	252,328	253,136	253,078	252,517	251,957	251,396	250,836	250,275	249,714	249,154	248,593	3,015,002
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		684,886	685,731	687,926	687,769	686,245	684,721	683,198	681,674	680,151	678,627	677,104	675,580	8,193,614
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.47% (Note 2)		223,943	223,943	225,905	227,868	227,868	227,868	227,868	227,868	227,868	227,868	227,868	227,868	2,724,603
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		71,444	71,444	72,896	72,896	72,696	72,696	72,696	72,696	72,696	72,696	72,696	72,896	869,848
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,232,293	1,233,446	1,239,863	1,241,411	1,239,326	1,237,242	1,235,158	1,233,074	1,230,990	1,228,905	1,226,822	1,224,737	14,803,067
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,232,293	1,233,446	1,239,863	1,241,411	1,239,326	1,237,242	1,235,158	1,233,074	1,230,990	1,228,905	1,226,822	1,224,737	14,803,067

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Note 2: The depreciation rate for project 7.4i is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result the blended rate shown above is based on approximately 98% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, 2% of the investment in FERC account 315 at an approved depreciation rate of 1.0%.

For Project: CAIR Crystal River AFUDC - CR4 FGD (Project 7.4j)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	139,574,596	
3	Less: Accumulated Depreciation		(9,062,449)	(9,350,903)	(9,639,357)	(9,927,811)	(10,216,265)	(10,504,719)	(10,793,173)	(11,081,627)	(11,370,081)	(11,658,535)	(11,946,989)	(12,235,443)	(12,523,897)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		130,512,147	130,223,693	129,935,239	129,646,785	129,358,331	129,069,877	128,781,423	128,492,969	128,204,515	127,916,061	127,627,607	127,339,153	127,050,699	
6	Average Net Investment			130,367,920	130,079,466	129,791,012	129,502,558	129,214,104	128,925,650	128,637,196	128,348,742	128,060,288	127,771,834	127,483,380	127,194,926	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		320,746	320,036	319,326	318,617	317,907	317,197	316,488	315,778	315,068	314,359	313,649	312,939	3,802,110
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		871,664	869,735	867,806	865,878	863,949	862,020	860,092	858,163	856,234	854,306	852,377	850,448	10,332,872
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.48% (Note 2)		288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	288,454	3,461,448
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	91,654	1,099,848
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,572,518	1,569,879	1,567,240	1,564,603	1,561,964	1,559,325	1,556,688	1,554,049	1,551,410	1,548,773	1,546,134	1,543,495	18,696,078
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,572,518	1,569,879	1,567,240	1,564,603	1,561,964	1,559,325	1,556,688	1,554,049	1,551,410	1,548,773	1,546,134	1,543,495	18,696,078

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Note 2: The depreciation rate for project 7.4j is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result the blended rate shown above is based on approximately 98.75% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, 1.10% of the investment in FERC account 315 at an approved depreciation rate of 1.0% and 0.15% of the investment in FERC account 311 at an approved depreciation rate of 1.50%.

For Project: CAIR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	
3	Less: Accumulated Depreciation	(Note 3)	(1,582,742)	(1,625,068)	(1,667,394)	(1,709,720)	(1,752,046)	(1,794,372)	(1,836,698)	(1,879,024)	(1,921,350)	(1,963,676)	(2,006,002)	(2,048,328)	(2,090,654)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		19,405,454	19,363,128	19,320,802	19,278,476	19,236,150	19,193,824	19,151,498	19,109,172	19,066,846	19,024,520	18,982,194	18,939,868	18,897,542	
6	Average Net Investment			19,384,291	19,341,965	19,299,639	19,257,313	19,214,987	19,172,661	19,130,335	19,088,009	19,045,683	19,003,357	18,961,031	18,918,705	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		47,691	47,587	47,483	47,379	47,275	47,171	47,067	46,962	46,858	46,754	46,650	46,548	565,423
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		129,607	129,324	129,041	128,758	128,475	128,192	127,909	127,626	127,343	127,060	126,777	126,494	1,536,606
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.42% (Note 2)		42,326	42,326	42,326	42,326	42,326	42,326	42,326	42,326	42,326	42,326	42,326	42,326	507,912
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	13,782	165,384
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			233,406	233,019	232,632	232,245	231,858	231,471	231,084	230,696	230,309	229,922	229,535	229,148	2,775,325
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			233,406	233,019	232,632	232,245	231,858	231,471	231,084	230,696	230,309	229,922	229,535	229,148	2,775,325

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Note 2: The depreciation rate for project 7.4k is a blended rate of the approved depreciation rates associated with the appropriate FERC accounts. PEF submitted new property units in 2012 and completed the unitization process for the CAIR projects. As a result the blended rate shown above is based on approximately 94.5% of the investment in FERC account 312 at an approved depreciation rate of 2.50%, 5% of the investment in FERC account 315 at an approved depreciation rate of 1.0% and 0.5% of the investment in FERC account 311 at an approved depreciation rate of 2.10%.

Note 3: Beginning Balance differs from CPD ending balance in the 2012 Estimated / Actual filing in Exhibit_(TGF-2) due to a correction to the depreciation expense. PEF has placed a credit in Line 1. Project 7.4 (January 2013) in schedule 42 3P in Exhibit_(TGF-3) to adjust for this revenue requirement.

For Project: CAIR Crystal River AFUDC - CR5 Acid Mist Mitigation Controls (Project 7.4l)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	
3	Less: Accumulated Depreciation		(617,254)	(636,851)	(656,448)	(676,045)	(695,642)	(715,239)	(734,836)	(754,433)	(774,030)	(793,627)	(813,224)	(832,821)	(852,418)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		8,789,451	8,769,854	8,750,257	8,730,660	8,711,063	8,691,466	8,671,869	8,652,272	8,632,675	8,613,078	8,593,481	8,573,884	8,554,287	
6	Average Net Investment			8,779,653	8,760,056	8,740,459	8,720,862	8,701,265	8,681,668	8,662,071	8,642,474	8,622,877	8,603,280	8,583,683	8,564,086	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		21,601	21,552	21,504	21,456	21,408	21,360	21,311	21,263	21,215	21,167	21,119	21,070	256,026
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		58,702	58,571	58,440	58,309	58,178	58,047	57,918	57,785	57,654	57,523	57,392	57,261	695,778
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	235,164
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	74,124
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			106,077	105,897	105,718	105,539	105,360	105,181	105,001	104,822	104,643	104,464	104,285	104,105	1,261,092
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			106,077	105,897	105,718	105,539	105,360	105,181	105,001	104,822	104,643	104,464	104,285	104,105	1,261,092

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

For Project: CAIR Crystal River AFUDC - FGD Settling Pond (Project 7.4m)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,318	
3	Less: Accumulated Depreciation		(315,924)	(325,521)	(335,118)	(344,715)	(354,312)	(383,909)	(373,506)	(383,103)	(392,700)	(402,297)	(411,894)	(421,491)	(431,088)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		7,361,392	7,351,795	7,342,198	7,332,601	7,323,004	7,313,407	7,303,810	7,294,213	7,284,616	7,275,019	7,265,422	7,255,825	7,246,228	
6	Average Net Investment			7,356,593	7,346,996	7,337,399	7,327,802	7,318,205	7,308,608	7,299,011	7,289,414	7,279,617	7,270,220	7,260,623	7,251,028	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	**2.95%** (Note 1)		18,100	18,078	18,052	18,029	18,005	17,961	17,958	17,934	17,911	17,687	17,863	17,840	215,636
	b. Equity Component Grossed Up For Taxes	**8.02%** (Note 1)		49,188	49,123	49,059	48,995	48,931	48,867	48,803	48,738	48,674	48,610	48,546	48,482	586,016
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	**1.50%**		9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	115,164
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	**0.007880**		5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041	60,492
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			81,926	81,837	81,749	81,662	81,574	81,486	81,399	81,310	81,223	81,135	81,047	80,960	977,308
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			81,926	81,837	81,749	81,662	81,574	81,486	81,399	81,310	81,223	81,135	81,047	80,960	977,308

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

For Project: CAIR Crystal River AFUDC - Coal Pile Runoff Treatment System (Project 7.4n)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	
3	Less: Accumulated Depreciation		(688,568)	(708,529)	(728,490)	(748,451)	(768,412)	(788,373)	(808,334)	(828,295)	(848,256)	(868,217)	(888,178)	(908,139)	(928,100)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		15,280,538	15,260,577	15,240,616	15,220,655	15,200,694	15,180,733	15,160,772	15,140,811	15,120,850	15,100,889	15,080,928	15,060,967	15,041,006	
6	Average Net Investment			15,270,558	15,250,597	15,230,636	15,210,675	15,190,714	15,170,753	15,150,792	15,130,831	15,110,870	15,090,909	15,070,948	15,050,987	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	**2.95%** (Note 1)		37,570	37,521	37,472	37,423	37,374	37,325	37,276	37,227	37,177	37,126	37,079	37,030	447,802
	b. Equity Component Grossed Up For Taxes	**8.02%** (Note 1)		102,102	101,968	101,835	101,701	101,566	101,434	101,301	101,167	101,034	100,901	100,767	100,834	1,216,412
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	**1.50%**		19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	239,532
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	**0.007880**		10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	10,486	125,832
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			170,119	169,936	169,754	169,571	169,389	169,206	169,024	168,841	168,656	168,476	168,293	168,111	2,029,378
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			170,119	169,936	169,754	169,571	169,389	169,206	169,024	168,841	168,656	168,476	168,293	168,111	2,029,378

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

For Project: CAIR Crystal River AFUDC - Dibasic Acid Additive System (Project 7.4o)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	
3	Less: Accumulated Depreciation		(63,472)	(65,752)	(68,032)	(70,312)	(72,592)	(74,872)	(77,152)	(79,432)	(81,712)	(83,992)	(86,272)	(88,552)	(90,832)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,030,947	1,028,667	1,026,387	1,024,107	1,021,827	1,019,547	1,017,267	1,014,987	1,012,707	1,010,427	1,008,147	1,005,867	1,003,587	
6	Average Net Investment			1,029,807	1,027,527	1,025,247	1,022,967	1,020,687	1,018,407	1,016,127	1,013,847	1,011,567	1,009,287	1,007,007	1,004,727	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		2,534	2,528	2,522	2,517	2,511	2,506	2,500	2,494	2,489	2,483	2,478	2,472	30,034
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		6,885	6,870	6,855	6,840	6,824	6,809	6,794	6,779	6,764	6,748	6,733	6,718	81,819
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	27,360
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		719	719	719	719	719	719	719	719	719	719	719	719	6,628
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			12,418	12,397	12,376	12,356	12,334	12,314	12,293	12,272	12,252	12,230	12,210	12,189	147,641
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			12,418	12,397	12,376	12,356	12,334	12,314	12,293	12,272	12,252	12,230	12,210	12,189	147,641

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

For Project: CAIR Crystal River AFUDC - Bottom Ash (PH)/Fly Ash (Ammonia) (Project 7.4p)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	18,241,238	
3	Less: Accumulated Depreciation		(31,555)	(63,477)	(95,399)	(127,321)	(159,243)	(191,165)	(223,087)	(255,009)	(286,931)	(318,853)	(350,775)	(382,697)	(414,619)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		18,209,884	18,177,762	18,145,840	18,113,918	18,081,996	18,050,074	18,018,152	17,986,230	17,954,308	17,922,386	17,890,464	17,858,542	17,826,620	
6	Average Net Investment			18,193,723	18,161,801	18,129,879	18,097,957	18,066,035	18,034,113	18,002,191	17,970,269	17,938,347	17,906,425	17,874,503	17,842,581	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95% (Note 1)		44,782	44,684	44,605	44,527	44,448	44,370	44,291	44,212	44,134	44,055	43,977	43,898	531,963
	b. Equity Component Grossed Up For Taxes	8.02% (Note 1)		121,647	121,433	121,220	121,006	120,793	120,579	120,366	120,152	119,939	119,726	119,512	119,299	1,445,672
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.10%		31,922	31,922	31,922	31,922	31,922	31,922	31,922	31,922	31,922	31,922	31,922	31,922	383,064
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978	143,736
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			210,309	210,017	209,725	209,433	209,141	208,849	208,557	208,264	207,973	207,681	207,389	207,097	2,504,435
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			210,309	210,017	209,725	209,433	209,141	208,849	208,557	208,264	207,973	207,681	207,389	207,097	2,504,435

Note 1: Consistent with Order No.PSC-12-0425-PAA-EU, in 2013 PEF will calculate the allowable return on CAIR investments using the approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

PROGRESS EN[redacted]RIDA
Environmental C[redacted]covery Clause (ECRC)
Capital Programs Detail Support - January 2013 through December 2013
CAIR/CAMR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	Period Total
1	Investments															
	a. Expenditures/Additions			150,000	286,364	286,364	286,364	286,364	286,364	336,364	336,364	336,364	336,364	336,364	294,364	3,558,000
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		519,751	669,751	956,115	1,242,478	1,528,842	1,815,206	2,101,569	2,437,933	2,774,297	3,110,660	3,447,024	3,783,387	4,077,751	
5	Net Investment (Lines 2 + 3 + 4)		519,751	669,751	956,115	1,242,478	1,528,842	1,815,206	2,101,569	2,437,933	2,774,297	3,110,660	3,447,024	3,783,387	4,077,751	
6	Average Net Investment			594,751	812,933	1,099,297	1,385,660	1,672,024	1,958,387	2,269,751	2,606,115	2,942,478	3,278,842	3,615,206	3,930,569	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.46%		1,219	1,667	2,254	2,841	3,426	4,015	4,653	5,343	6,032	6,722	7,411	8,058	53,643
	b. Equity Component Grossed Up For Taxes	7.80%		3,865	5,283	7,144	9,005	10,868	12,726	14,750	16,936	19,122	21,307	23,493	25,543	170,040
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.11%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007880		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,084	6,950	9,398	11,846	14,294	16,741	19,403	22,279	25,154	28,029	30,904	33,601	223,683
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			5,084	6,950	9,398	11,846	14,294	16,741	19,403	22,279	25,154	28,029	30,904	33,601	223,683

Note 1: Consistent with the Stipulation and Settlement Order No. PSC-12-0104-FOF-EI in Docket 120022-EI these assets are not projected to be in-service by year end 2013 and accordingly will not be moved to base rates in 2014.

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes	7.80%		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
8	Investment Expenses															
	a. Depreciation	2.50%		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. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009280		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-13	Projected Feb-13	Projected Mar-13	Projected Apr-13	Projected May-13	Projected Jun-13	Projected Jul-13	Projected Aug-13	Projected Sep-13	Projected Oct-13	Projected Nov-13	Projected Dec-13	End of Period Total
1	Investments															
	a. Expenditures/Additions			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant			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	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation		(20,866)	(21,378)	(21,890)	(22,402)	(22,914)	(23,426)	(23,938)	(24,450)	(24,962)	(25,474)	(25,986)	(26,498)	(27,010)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		340,870	340,358	339,846	339,334	338,822	336,310	337,798	337,288	336,774	336,262	335,750	335,238	334,726	
6	Average Net Investment			340,614	340,102	339,590	339,076	338,566	338,054	337,542	337,030	336,516	336,006	335,494	334,982	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.46% x 1/12)	2.46%		696	697	696	695	694	693	692	691	690	689	688	687	8,310
	b. Equity Component Grossed Up For Taxes	7.80%		2,213	2,210	2,207	2,203	2,200	2,197	2,193	2,190	2,187	2,184	2,180	2,177	26,341
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
6	Investment Expenses															
	a. Depreciation	1.70%		512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009280		280	280	280	260	280	280	280	280	280	280	280	280	3,360
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,703	3,699	3,695	3,690	3,688	3,682	3,677	3,673	3,669	3,665	3,660	3,656	44,155
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,703	3,699	3,695	3,690	3,688	3,682	3,677	3,673	3,669	3,665	3,660	3,656	44,155

DOCKET NO. 120007-EI
FINAL ECRC 2011 TRUE-UP
EXHIBIT HTB-1

INDEX

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2011 THROUGH DECEMBER 2011

FORMS 42-1A THROUGH 42-9A

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 32
PARTY Tampa Electric Company
DESCRIPTION Howard T. Bryant (HTB-1), Final Env. Cost Rec
DATE Forms 42-1A through 42-9A for 1/11-12/11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011
(in Dollars)

Form 42 - 1A

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2011 to December 2011 (Form 42-2A, Lines 5 + 6 + 10)	($3,696,541)
2.	Estimated/Actual True-Up Amount Approved for the Period January 2011 to December 2011 (Order No. PSC-11-0553 FOF-EI)	(464,090)
3	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2013 to December 2013 (Lines 1 - 2)	($3,232,451)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Form 42 - 2A

Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	ECRC Revenues (net of Revenue Taxes)	$6,513,784	$5,431,604	$5,013,741	$5,428,243	$6,375,391	$7,008,986	$7,206,392	$7,448,255	$7,422,081	$6,299,691	$5,202,358	$5,271,980	$74,622,506
2.	True-Up Provision	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,262	3,987,122
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)[1]	6,846,044	5,763,864	5,346,001	5,760,503	6,707,651	7,341,246	7,538,652	7,780,515	7,754,341	6,631,951	5,534,618	5,604,242	78,609,628
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	1,635,285	1,985,917	2,431,264	1,700,762	2,788,262	1,185,237	1,846,955	1,914,178	1,880,908	1,906,368	1,401,326	1,575,962	22,252,424
	b. Capital Investment Projects (Form 42-7A, Line 9)	5,000,601	4,994,088	5,015,263	4,998,322	4,998,525	4,993,023	4,988,082	4,993,438	5,001,881	5,016,877	5,018,625	5,031,178	60,049,903
	c. Total Jurisdictional ECRC Costs	6,635,886	6,980,005	7,446,527	6,699,084	7,786,787	6,178,260	6,835,037	6,907,616	6,882,789	6,923,245	6,419,951	6,607,140	82,302,327
5.	Over/Under Recovery (Line 3 - Line 4c)[1]	210,158	(1,216,141)	(2,100,526)	(938,581)	(1,079,136)	1,162,986	703,615	872,899	871,552	(291,294)	(885,333)	(1,002,898)	(3,692,699)
6.	Interest Provision (Form 42-3A, Line 10)	275	100	(288)	(539)	(706)	(650)	(528)	(395)	(238)	(241)	(350)	(282)	(3,842)
7.	Beginning Balance True-Up & Interest Provision	3,987,122	3,865,295	2,316,994	(116,080)	(1,387,460)	(2,799,562)	(1,969,486)	(1,598,659)	(1,058,415)	(519,361)	(1,143,156)	(2,361,099)	3,987,122
	a. Deferred True-Up from January to December 2010	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)
8.	True-Up Collected/(Refunded) (see Line 2)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,262)	(3,987,122)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)[1]	1,248,487	(299,814)	(2,732,888)	(4,004,268)	(5,416,370)	(4,586,294)	(4,215,467)	(3,675,223)	(3,136,169)	(3,759,964)	(4,977,907)	(6,313,349)	(6,313,349)
10.	Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11.	End of Period Total True-Up (Lines 9 + 10)[1]	$1,248,487	($299,814)	($2,732,888)	($4,004,268)	($5,416,370)	($4,586,294)	($4,215,467)	($3,675,223)	($3,136,169)	($3,759,964)	($4,977,907)	($6,313,349)	($6,313,349)

[1] Subject to Baseline Analytics

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Form 42 - 3A

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$1,370,314	$1,248,487	($299,814)	($2,732,888)	($4,004,268)	($5,416,370)	($4,586,294)	($4,215,467)	($3,675,223)	($3,136,169)	($3,759,964)	($4,977,907)	
2.	Ending True-Up Amount Before Interest	1,248,212	(299,914)	(2,732,600)	(4,003,729)	(5,415,664)	(4,585,644)	(4,214,939)	(3,674,828)	(3,135,931)	(3,759,723)	(4,977,557)	(6,313,067)	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	2,618,526	948,573	(3,032,414)	(6,736,617)	(9,419,932)	(10,002,014)	(8,801,233)	(7,890,295)	(6,811,154)	(6,895,892)	(8,737,521)	(11,290,974)	
4.	Average True-Up Amount (Line 3 x 1/2)	1,309,263	474,287	(1,516,207)	(3,368,309)	(4,709,966)	(5,001,007)	(4,400,617)	(3,945,148)	(3,405,577)	(3,447,946)	(4,368,761)	(5,645,487)	
5.	Interest Rate (First Day of Reporting Business Month)	0.25%	0.25%	0.25%	0.20%	0.19%	0.16%	0.16%	0.12%	0.11%	0.06%	0.11%	0.08%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.25%	0.25%	0.20%	0.19%	0.16%	0.16%	0.12%	0.11%	0.06%	0.11%	0.08%	0.03%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.50%	0.50%	0.45%	0.39%	0.35%	0.32%	0.28%	0.23%	0.17%	0.17%	0.19%	0.11%	
8.	Average Interest Rate (Line 7 x 1/2)	0.250%	0.250%	0.225%	0.195%	0.175%	0.160%	0.140%	0.115%	0.085%	0.085%	0.095%	0.055%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.021%	0.021%	0.019%	0.016%	0.015%	0.013%	0.012%	0.010%	0.007%	0.007%	0.008%	0.005%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$275	$100	($288)	($539)	($706)	($650)	($528)	($395)	($238)	($241)	($350)	($282)	($3,842)

[1] Subject to Baseline Analytics

Tampa Electric Company Form 42 - 4A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual/Estimated	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$5,932,439	$5,544,173	$388,266	7.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	17,174	26,956	(9,782)	-36.3%
	d. Big Bend Units 1 & 2 FGD	8,153,964	7,629,441	524,523	6.9%
	e. Big Bend PM Minimization and Monitoring	441,560	279,413	162,147	58.0%
	f. Big Bend NO_x Emissions Reduction	328,802	379,930	(51,128)	-13.5%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	7,525	73,495	(65,970)	-89.8%
	i. Polk NO_x Emissions Reduction	(19,672)	(20,284)	612	-3.0%
	j. Bayside SCR Consumables	134,727	102,108	32,619	31.9%
	k. Big Bend Unit 4 SOFA	0	0	0	0.0%
	l. Big Bend Unit 1 Pre-SCR	249	249	0	0.0%
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0.0%
	n. Big Bend Unit 3 Pre-SCR	200	200	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	72,883	54,260	18,623	34.3%
	p. Arsenic Groundwater Standard Program	116,826	119,369	(2,543)	-2.1%
	q. Big Bend 1 SCR	2,143,465	1,992,957	150,508	7.6%
	r. Big Bend 2 SCR	1,501,661	1,280,394	221,267	17.3%
	s. Big Bend 3 SCR	1,850,833	1,856,640	(5,807)	-0.3%
	t. Big Bend 4 SCR	1,535,119	1,441,134	93,985	6.5%
	u. Clean Air Mercury Rule	24,267	26,839	(2,572)	-9.6%
	v. Greenhouse Gas Reduction Program	92,541	42,958	49,583	115.4%
2.	Total Investment Projects - Recoverable Costs	$22,369,063	$20,864,732	$1,504,331	7.2%
3.	Recoverable Costs Allocated to Energy	22,137,329	20,583,107	$1,554,221	7.6%
4.	Recoverable Costs Allocated to Demand	$231,734	$281,625	($49,890)	-17.7%

Notes:

Column (1) is the End of Period Totals on Form 42-5A.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42 - 5A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integratio	$478,812	$508,795	$705,148	$556,426	$463,472	$571,584	$394,582	$497,936	$554,685	$414,529	$408,132	$378,338	$5,932,439		$5,932,439
	b. Big Bend Units 1 & 2 Flue Gas Conditioning													0		0
	c. SO_2 Emissions Allowances	1,750	328	2,030	1,191	4,640	3,328	2,821	1,124	326	(119)	(140)	(105)	17,174		17,174
	d. Big Bend Units 1 & 2 FGD	564,431	1,061,495	687,720	637,459	974,592	751,225	625,916	707,401	528,310	621,549	443,388	550,478	8,153,964		8,153,964
	e. Big Bend PM Minimization and Monitoring	12,796	39,264	26,228	27,530	27,135	27,942	31,924	27,713	49,511	71,445	71,053	29,019	441,560		441,560
	f. Big Bend NO_x Emissions Reduction	263	57,228	39,710	37,302	22,960	(3,881)	2,396	538	35,712	55,326	46,261	34,988	328,802		328,802
	g. NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
	h. Gannon Thermal Discharge Study	0	0	0	1,480	840	3,675	0	0	0	250	1,280	0	7,525	7,525	
	i. Polk NO_x Reduction	747	(36,480)	897	206	26	320	5	1,433	1,442	1,811	8,132	1,789	(19,672)		(19,672)
	j. Bayside SCR and Ammonia	23,455	0	0	12,121	0	13,330	14,065	15,102	26,767	14,680	0	15,206	134,727		134,727
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	249	0	0	0	0	0	0	0	0	0	0	0	249		249
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	n. Big Bend Unit 3 Pre-SCR	200	0	0	0	0	0	0	0	0	0	0	0	200		200
	o. Clean Water Act Section 316(b) Phase II Study	0	0	960	4,800	7,560	13,440	8,080	6,440	3,320	715	9,790	17,778	72,883	72,883	
	p. Arsenic Groundwater Standard Program	0	19,362	5,817	0	22,191	0	20,371	16,650	0	19,700	9,471	3,265	116,826	116,826	
	q. Big Bend 1 SCR	176,235	125,027	148,707	116,980	447,715	(96,579)	273,569	197,958	208,975	220,091	146,289	178,499	2,143,465		2,143,465
	r. Big Bend 2 SCR	155,491	45,189	83,516	117,010	288,343	(75,002)	166,811	151,508	220,286	109,248	81,497	157,765	1,501,661		1,501,661
	s. Big Bend 3 SCR	112,727	133,826	119,310	96,454	391,580	10,033	156,516	184,073	168,550	236,175	106,422	135,155	1,850,833		1,850,833
	t. Big Bend 4 SCR	77,789	48,479	603,554	50,535	147,556	(27,175)	159,127	109,474	88,363	137,252	62,385	77,781	1,535,119		1,535,119
	u. Clean Air Mercury Rule	0	0	0	332	6,071	436	1,816	4,826	929	1,509	8,348	0	24,267		24,267
	v. Greenhouse Gas Reduction Program	10,009	0	17,265	53,172	2,513	0	563	1,211	287	4,973	2,550	0	92,541		92,541
2.	Total of O&M Activities[1]	1,649,456	2,002,512	2,440,862	1,713,007	2,807,192	1,192,676	1,858,563	1,923,387	1,887,462	1,909,133	1,404,857	1,579,956	22,369,063	$231,734	$22,137,330
3.	Recoverable Costs Allocated to Energy	1,614,956	1,983,150	2,434,085	1,706,727	2,776,601	1,175,561	1,830,112	1,900,297	1,884,142	1,888,468	1,384,317	1,558,913	22,137,329		
4.	Recoverable Costs Allocated to Demand	34,500	19,362	6,777	6,280	30,591	17,115	28,451	23,090	3,320	20,665	20,540	21,043	231,734		
5.	Retail Energy Jurisdictional Factor	0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769			
6.	Retail Demand Jurisdictional Factor	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819			
7.	Jurisdictional Energy Recoverable Costs (A)	1,601,907	1,967,185	2,424,707	1,694,686	2,758,666	1,168,679	1,819,429	1,891,839	1,877,696	1,886,375	1,381,454	1,555,603	22,028,226		
8.	Jurisdictional Demand Recoverable Costs (B)	33,378	18,732	6,557	6,076	29,596	16,558	27,526	22,339	3,212	19,993	19,872	20,359	224,198		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,635,285	$1,985,917	$2,431,264	$1,700,762	$2,788,262	$1,185,237	$1,846,955	$1,914,178	$1,880,908	$1,906,368	$1,401,326	$1,575,962	$22,252,424		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

[1] Subject to Baseline Analytics

Tampa Electric Company Form 42 - 6A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Percent
1.	Description of Investment Projects				
a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$742,882	$742,259	$623	0.1%
b.	Big Bend Units 1 & 2 Flue Gas Conditioning	403,377	403,377	0	0.0%
c.	Big Bend Unit 4 Continuous Emissions Monitors	76,381	76,381	0	0.0%
d.	Big Bend Fuel Oil Tank # 1 Upgrade	51,572	51,572	0	0.0%
e.	Big Bend Fuel Oil Tank # 2 Upgrade	84,824	84,824	0	0.0%
f.	Phillips Upgrade Tank # 1 for FDEP	5,461	5,461	0	0.0%
g.	Phillips Upgrade Tank # 4 for FDEP	8,584	8,584	0	0.0%
h.	Big Bend Unit 1 Classifier Replacement	128,734	128,734	0	0.0%
i.	Big Bend Unit 2 Classifier Replacement	93,421	93,421	0	0.0%
j.	Big Bend Section 114 Mercury Testing Platform	13,022	13,022	0	0.0%
k.	Big Bend Units 1 & 2 FGD	8,654,904	8,682,949	(28,045)	-0.3%
l.	Big Bend FGD Optimization and Utilization	2,417,303	2,417,303	0	0.0%
m.	Big Bend NO_x Emissions Reduction	781,211	781,211	0	0.0%
n.	Big Bend PM Minimization and Monitoring	1,066,060	1,062,080	3,980	0.4%
o.	Polk NO_x Emissions Reduction	189,422	189,422	0	0.0%
p.	Big Bend Unit 4 SOFA	310,809	310,809	0	0.0%
q.	Big Bend Unit 1 Pre-SCR	218,293	218,293	0	0.0%
r.	Big Bend Unit 2 Pre-SCR	207,873	207,873	0	0.0%
s.	Big Bend Unit 3 Pre-SCR	358,814	358,814	0	0.0%
t.	Big Bend Unit 1 SCR	11,720,715	11,720,715	0	0.0%
u.	Big Bend Unit 2 SCR	12,562,237	12,562,769	(532)	0.0%
v.	Big Bend Unit 3 SCR	10,430,515	10,430,446	69	0.0%
w.	Big Bend Unit 4 SCR	7,950,899	7,950,899	0	0.0%
x.	Big Bend FGD System Reliability	1,710,188	1,732,791	(22,603)	-1.3%
y.	Clean Air Mercury Rule	164,667	164,511	156	0.1%
z.	SO_2 Emissions Allowances	(4,559)	(4,556)	(3)	0.1%
2.	Total Investment Projects - Recoverable Costs	$60,347,609	$60,393,964	($46,355)	-0.1%
3.	Recoverable Costs Allocated to Energy	$60,197,168	$60,243,523	($46,355)	-0.1%
4.	Recoverable Costs Allocated to Demand	$150,441	$150,441	$0	0.0%

Notes:

Column (1) is the End of Period Totals on Form 42-7A
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Form 42-7A

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line	Description (A)	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1. a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$62,698	$62,545	$62,392	$62,238	$62,085	$61,931	$61,779	$61,625	$61,471	$61,318	$61,168	$61,632	$742,882		$742,882
b.	Big Bend Units 1 and 2 Flue Gas Conditioning	34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377		403,377
c.	Big Bend Unit 4 Continuous Emissions Monitors	6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381		76,381
d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572	$ 51,572	
e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824	84,824	
f.	Phillips Upgrade Tank # 1 for FDEP	463	461	460	458	457	456	454	453	452	450	449	448	5,461	5,461	
g.	Phillips Upgrade Tank # 4 for FDEP	727	726	723	721	719	716	714	712	710	707	706	703	8,584	8,584	
h.	Big Bend Unit 1 Classifier Replacement	10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734		128,734
i.	Big Bend Unit 2 Classifier Replacement	7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421		93,421
j.	Big Bend Section 114 Mercury Testing Platform	1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022		13,022
k.	Big Bend Units 1 & 2 FGD	723,838	722,116	722,809	724,293	724,399	722,532	720,663	718,899	717,955	717,644	720,001	719,755	8,654,904		8,654,904
l.	Big Bend FGD Optimization and Utilization	203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303		2,417,303
m.	Big Bend NO_x Emissions Reduction	65,546	65,466	65,384	65,303	65,223	65,141	65,061	64,979	64,898	64,818	64,736	64,656	781,211		781,211
n.	Big Bend PM Minimization and Monitoring	89,638	89,437	89,230	89,023	88,817	88,611	88,404	88,269	88,171	88,547	88,957	88,956	1,066,060		1,066,060
o.	Polk NO_x Emissions Reduction	16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422		189,422
p.	Big Bend Unit 4 SOFA	26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809		310,809
q.	Big Bend Unit 1 Pre-SCR	18,433	18,389	18,345	18,301	18,257	18,214	18,169	18,125	18,081	18,037	17,993	17,949	218,293		218,293
r.	Big Bend Unit 2 Pre-SCR	17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873		207,873
s.	Big Bend Unit 3 Pre-SCR	30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814		358,814
t.	Big Bend Unit 1 SCR	985,104	983,452	981,692	979,901	978,444	977,009	977,044	975,233	973,424	971,614	969,804	967,994	11,720,715		11,720,715
u.	Big Bend Unit 2 SCR	1,054,833	1,053,014	1,051,128	1,049,230	1,047,648	1,045,741	1,044,105	1,042,469	1,041,496	1,042,215	1,043,731	1,046,627	12,562,237		12,562,237
v.	Big Bend Unit 3 SCR	866,391	867,478	870,987	872,230	874,164	872,744	871,318	869,887	868,457	867,047	865,626	864,186	10,430,515		10,430,515
w.	Big Bend Unit 4 SCR	668,375	667,320	666,266	665,211	664,156	663,102	662,047	660,993	659,939	658,884	657,830	656,776	7,950,899		7,950,899
x.	Big Bend FGD System Reliability	126,436	126,219	128,153	130,541	131,022	131,458	133,694	141,075	151,815	159,862	167,568	182,345	1,710,188		1,710,188
y.	Clean Air Mercury Rule	13,703	13,674	13,646	13,727	13,807	13,779	13,750	13,722	13,694	13,666	13,637	13,862	164,667		164,667
z.	SO_2 Emissions Allowances (B)	(386)	(385)	(384)	(382)	(382)	(381)	(379)	(378)	(377)	(376)	(375)	(374)	(4,559)		(4,559)
2.	Total Investment Projects - Recoverable Costs	5,041,649	5,034,930	5,035,023	5,034,160	5,031,352	5,022,762	5,017,705	5,016,115	5,019,415	5,022,835	5,029,404	5,042,259	60,347,609	$ 150,441	$ 60,197,168
3.	Recoverable Costs Allocated to Energy	5,028,940	5,022,252	5,022,376	5,021,545	5,018,769	5,010,210	5,005,185	5,003,626	5,006,955	5,010,408	5,017,008	5,029,894	60,197,168		
4.	Recoverable Costs Allocated to Demand	12,709	12,678	12,647	12,615	12,583	12,552	12,520	12,489	12,460	12,427	12,396	12,365	150,441		
5.	Retail Energy Jurisdictional Factor	0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9956490	0.9965789	0.9988915	0.9979319	0.9978769			
6.	Retail Demand Jurisdictional Factor	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819			
7.	Jurisdictional Energy Recoverable Costs (C)	4,988,305	4,981,822	5,003,027	4,986,117	4,986,351	4,980,879	4,975,969	4,981,355	4,989,826	5,004,854	5,006,632	5,019,215	59,904,352		
8.	Jurisdictional Demand Recoverable Costs (D)	12,296	12,266	12,236	12,205	12,174	12,144	12,113	12,083	12,055	12,023	11,993	11,963	145,551		
9.	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$5,000,601	$4,994,088	$5,015,263	$4,998,322	$4,998,525	$4,993,023	$4,988,082	$4,993,438	$5,001,881	$5,016,877	$5,018,625	$5,031,178	$60,049,903		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Project's Total Return Component on Form 42-8A, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

[1] Subject to Baseline Analytics

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ECRC 2011 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$680	$126,330	$127,010
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	
3.	Less: Accumulated Depreciation	(3,400,809)	(3,416,602)	(3,432,395)	(3,448,188)	(3,463,981)	(3,479,774)	(3,495,567)	(3,511,360)	(3,527,153)	(3,542,946)	(3,558,739)	(3,574,532)	(3,590,325)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	680	127,010	
5.	Net Investment (Lines 2 + 3 + 4)	$4,838,849	4,823,056	4,807,263	4,791,470	4,775,677	4,759,884	4,744,091	4,728,298	4,712,505	4,696,712	4,680,919	4,665,806	4,776,343	
6.	Average Net Investment		4,830,953	4,815,160	4,799,367	4,783,574	4,767,781	4,751,988	4,736,195	4,720,402	4,704,609	4,688,816	4,673,363	4,721,075	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		35,100	34,985	34,871	34,756	34,641	34,526	34,412	34,297	34,182	34,067	33,955	34,302	$414,094
	b. Debt Component Grossed Up For Taxes (C)		11,805	11,767	11,728	11,689	11,651	11,612	11,574	11,535	11,496	11,458	11,420	11,537	139,272
8.	Investment Expenses														
	a. Depreciation (D)		15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	189,516
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		62,698	62,545	62,392	62,238	62,085	61,931	61,779	61,625	61,471	61,318	61,168	61,632	742,882
	a. Recoverable Costs Allocated to Energy		62,698	62,545	62,392	62,238	62,085	61,931	61,779	61,625	61,471	61,318	61,168	61,632	742,882
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		62,191	62,042	62,152	61,799	61,684	61,568	61,418	61,351	61,261	61,250	61,041	61,501	739,258
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$62,191	$62,042	$62,152	$61,799	$61,684	$61,568	$61,418	$61,351	$61,261	$61,250	$61,041	$61,501	$739,258

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

[1] Subject to Baseline Analytics

DOCKET NO. 120007-EI
ECRC 2011 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(2,856,218)	(2,869,627)	(2,883,036)	(2,896,445)	(2,909,854)	(2,923,263)	(2,936,672)	(2,950,081)	(2,963,490)	(2,976,899)	(2,990,308)	(3,003,717)	(3,017,126)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,161,516	2,148,107	2,134,698	2,121,289	2,107,880	2,094,471	2,081,062	2,067,653	2,054,244	2,040,835	2,027,426	2,014,017	2,000,608	
6.	Average Net Investment		2,154,812	2,141,403	2,127,994	2,114,585	2,101,176	2,087,767	2,074,358	2,060,949	2,047,540	2,034,131	2,020,722	2,007,313	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,656	15,559	15,461	15,364	15,266	15,169	15,072	14,974	14,877	14,779	14,682	14,584	$181,443
	b. Debt Component Grossed Up For Taxes (C)		5,266	5,233	5,200	5,167	5,135	5,102	5,069	5,036	5,004	4,971	4,938	4,905	61,026
8.	Investment Expenses														
	a. Depreciation (D)		13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	160,908
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377
	a. Recoverable Costs Allocated to Energy		34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		34,054	33,926	33,939	33,701	33,592	33,483	33,354	33,270	33,176	33,122	32,961	32,828	401,406
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$34,054	$33,926	$33,939	$33,701	$33,592	$33,483	$33,354	$33,270	$33,176	$33,122	$32,961	$32,828	$401,406

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

[1] Subject to Baseline Analytics

DOCKET NO. 120007-EI
ECRC 2011 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(357,653)	(359,169)	(360,685)	(362,201)	(363,717)	(365,233)	(366,749)	(368,265)	(369,781)	(371,297)	(372,813)	(374,329)	(375,845)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$508,558	507,042	505,526	504,010	502,494	500,978	499,462	497,946	496,430	494,914	493,398	491,882	490,366	
6.	Average Net Investment		507,800	506,284	504,768	503,252	501,736	500,220	498,704	497,188	495,672	494,156	492,640	491,124	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,690	3,678	3,667	3,656	3,645	3,634	3,623	3,612	3,601	3,590	3,579	3,568	$43,543
	b. Debt Component Grossed Up For Taxes (C)		1,241	1,237	1,233	1,230	1,226	1,222	1,219	1,215	1,211	1,208	1,204	1,200	14,646
8.	Investment Expenses														
	a. Depreciation (D)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381
	a. Recoverable Costs Allocated to Energy		6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		6,395	6,379	6,391	6,357	6,346	6,335	6,321	6,315	6,306	6,307	6,286	6,271	76,009
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,395	$6,379	$6,391	$6,357	$6,346	$6,335	$6,321	$6,315	$6,306	$6,307	$6,286	$6,271	$76,009

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(159,496)	(160,574)	(161,652)	(162,730)	(163,808)	(164,886)	(165,964)	(167,042)	(168,120)	(169,198)	(170,276)	(171,354)	(172,432)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$338,082	337,004	335,926	334,848	333,770	332,692	331,614	330,536	329,458	328,380	327,302	326,224	325,146	
6.	Average Net Investment		337,543	336,465	335,387	334,309	333,231	332,153	331,075	329,997	328,919	327,841	326,763	325,685	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,452	2,445	2,437	2,429	2,421	2,413	2,405	2,398	2,390	2,382	2,374	2,366	$28,912
	b. Debt Component Grossed Up For Taxes (C)		825	822	820	817	814	812	809	806	804	801	798	796	9,724
8.	Investment Expenses														
	a. Depreciation (D)		1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	12,936
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,213	4,204	4,194	4,183	4,173	4,163	4,152	4,143	4,133	4,122	4,112	4,102	49,894
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,213	$4,204	$4,194	$4,183	$4,173	$4,163	$4,152	$4,143	$4,133	$4,122	$4,112	$4,102	$49,894

Notes:

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(262,348)	(264,121)	(265,894)	(267,667)	(269,440)	(271,213)	(272,986)	(274,759)	(276,532)	(278,305)	(280,078)	(281,851)	(283,624)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$556,053	554,280	552,507	550,734	548,961	547,188	545,415	543,642	541,869	540,096	538,323	536,550	534,777	
6.	Average Net Investment		555,167	553,394	551,621	549,848	548,075	546,302	544,529	542,756	540,983	539,210	537,437	535,664	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,034	4,021	4,008	3,995	3,982	3,969	3,956	3,943	3,931	3,918	3,905	3,892	$47,554
	b. Debt Component Grossed Up For Taxes (C)		1,357	1,352	1,348	1,344	1,339	1,335	1,331	1,326	1,322	1,318	1,313	1,309	15,994
8.	Investment Expenses														
	a. Depreciation (D)		1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	21,276
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		6,931	6,914	6,897	6,881	6,863	6,847	6,830	6,813	6,798	6,781	6,764	6,747	82,066
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,931	$6,914	$6,897	$6,881	$6,863	$6,847	$6,830	$6,813	$6,798	$6,781	$6,764	$6,747	$82,066

Notes:

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	
3.	Less: Accumulated Depreciation	(24,252)	(24,395)	(24,538)	(24,681)	(24,824)	(24,967)	(25,110)	(25,253)	(25,396)	(25,539)	(25,682)	(25,825)	(25,968)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$33,025	32,882	32,739	32,596	32,453	32,310	32,167	32,024	31,881	31,738	31,595	31,452	31,309	
6.	Average Net Investment		32,954	32,811	32,668	32,525	32,382	32,239	32,096	31,953	31,810	31,667	31,524	31,381	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		239	238	237	236	235	234	233	232	231	230	229	228	$2,802
	b. Debt Component Grossed Up For Taxes (C)		81	80	80	79	79	79	78	78	78	77	77	77	943
8.	Investment Expenses														
	a. Depreciation (D)		143	143	143	143	143	143	143	143	143	143	143	143	1,716
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		463	461	460	458	457	456	454	453	452	450	449	448	5,461
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		463	461	460	458	457	456	454	453	452	450	449	448	5,461
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		448	446	445	443	442	441	439	438	437	435	434	433	5,281
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$448	$446	$445	$443	$442	$441	$439	$438	$437	$435	$434	$433	$5,281

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	
3.	Less: Accumulated Depreciation	(38,723)	(38,949)	(39,175)	(39,401)	(39,627)	(39,853)	(40,079)	(40,305)	(40,531)	(40,757)	(40,983)	(41,209)	(41,435)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$51,749	51,523	51,297	51,071	50,845	50,619	50,393	50,167	49,941	49,715	49,489	49,263	49,037	
6.	Average Net Investment		51,636	51,410	51,184	50,958	50,732	50,506	50,280	50,054	49,828	49,602	49,376	49,150	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		375	374	372	370	369	367	365	364	362	360	359	357	$4,394
	b. Debt Component Grossed Up For Taxes (C)		126	126	125	125	124	123	123	122	122	121	121	120	1,478
8.	Investment Expenses														
	a. Depreciation (D)		226	226	226	226	226	226	226	226	226	226	226	226	2,712
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		727	726	723	721	719	716	714	712	710	707	706	703	8,584
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		727	726	723	721	719	716	714	712	710	707	706	703	8,584
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		703	702	699	698	696	693	691	689	687	684	683	680	8,305
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$703	$702	$699	$698	$696	$693	$691	$689	$687	$684	$683	$680	$8,305

Notes:

(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Form 42-8A
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Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(562,472)	(566,092)	(569,712)	(573,332)	(576,952)	(580,572)	(584,192)	(587,812)	(591,432)	(595,052)	(598,672)	(602,292)	(605,912)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$753,785	750,165	746,545	742,925	739,305	735,685	732,065	728,445	724,825	721,205	717,585	713,965	710,345	
6.	Average Net Investment		751,975	748,355	744,735	741,115	737,495	733,875	730,255	726,635	723,015	719,395	715,775	712,155	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,464	5,437	5,411	5,385	5,358	5,332	5,306	5,279	5,253	5,227	5,201	5,174	$63,827
	b. Debt Component Grossed Up For Taxes (C)		1,838	1,829	1,820	1,811	1,802	1,793	1,784	1,776	1,767	1,758	1,749	1,740	21,467
8.	Investment Expenses														
	a. Depreciation (D)		3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	43,440
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734
	a. Recoverable Costs Allocated to Energy		10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		10,834	10,798	10,809	10,740	10,710	10,682	10,647	10,627	10,604	10,593	10,548	10,512	128,104
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,834	$10,798	$10,809	$10,740	$10,710	$10,682	$10,647	$10,627	$10,604	$10,593	$10,548	$10,512	$128,104

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(429,750)	(432,294)	(434,838)	(437,382)	(439,926)	(442,470)	(445,014)	(447,558)	(450,102)	(452,646)	(455,190)	(457,734)	(460,278)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$555,044	552,500	549,956	547,412	544,868	542,324	539,780	537,236	534,692	532,148	529,604	527,060	524,516	
6.	Average Net Investment		553,772	551,228	548,684	546,140	543,596	541,052	538,508	535,964	533,420	530,876	528,332	525,788	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,024	4,005	3,987	3,968	3,950	3,931	3,913	3,894	3,876	3,857	3,839	3,820	$47,064
	b. Debt Component Grossed Up For Taxes (C)		1,353	1,347	1,341	1,335	1,328	1,322	1,316	1,310	1,304	1,297	1,291	1,285	15,829
8.	Investment Expenses														
	a. Depreciation (D)		2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	30,528
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421
	a. Recoverable Costs Allocated to Energy		7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		7,857	7,832	7,842	7,792	7,771	7,751	7,728	7,714	7,698	7,689	7,658	7,633	92,965
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,857	$7,832	$7,842	$7,792	$7,771	$7,751	$7,728	$7,714	$7,698	$7,689	$7,658	$7,633	$92,965

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(28,471)	(28,672)	(28,873)	(29,074)	(29,275)	(29,476)	(29,677)	(29,878)	(30,079)	(30,280)	(30,481)	(30,682)	(30,883)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$92,266	92,065	91,864	91,663	91,462	91,261	91,060	90,859	90,658	90,457	90,256	90,055	89,854	
6.	Average Net Investment		92,166	91,965	91,764	91,563	91,362	91,161	90,960	90,759	90,558	90,357	90,156	89,955	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		670	668	667	665	664	662	661	659	658	657	655	654	$7,940
	b. Debt Component Grossed Up For Taxes (C)		225	225	224	224	223	223	222	222	221	221	220	220	2,670
8.	Investment Expenses														
	a. Depreciation (D)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022
	a. Recoverable Costs Allocated to Energy		1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		1,087	1,085	1,088	1,082	1,081	1,080	1,078	1,077	1,076	1,078	1,074	1,073	12,959
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,087	$1,085	$1,088	$1,082	$1,081	$1,080	$1,078	$1,077	$1,076	$1,078	$1,074	$1,073	$12,959

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$29,866	$34,024	$527,165	$197,000	$27,737	$7,659	$28,001	$29,086	$197,283	$159,085	$99,364	$268,331	$1,604,600
	b. Clearings to Plant		0	0	0	434,699	1,173	0	0	0	0	1,307,326	17,487	44,310	1,804,995
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$86,578,841	$86,578,841	$86,578,841	$86,578,841	$87,013,540	$87,014,713	$87,014,713	$87,014,713	$87,014,713	$87,014,713	$88,322,039	$88,339,525	$88,383,835	
3.	Less: Accumulated Depreciation	(34,264,197)	(34,473,429)	(34,682,661)	(34,891,893)	(35,101,125)	(35,311,408)	(35,521,694)	(35,731,980)	(35,942,266)	(36,152,552)	(36,362,838)	(36,576,283)	(36,789,770)	
4.	CWIP - Non-Interest Bearing	776,168	806,034	840,058	1,367,223	1,129,524	1,156,088	1,163,747	1,191,748	1,220,833	1,418,116	269,875	351,752	575,773	
5.	Net Investment (Lines 2 + 3 + 4)	$53,090,812	52,911,446	52,736,237	53,054,170	53,041,938	52,859,392	52,656,765	52,474,480	52,293,280	52,280,277	52,229,076	52,114,994	52,169,838	
6.	Average Net Investment		53,001,129	52,823,842	52,895,204	53,048,054	52,950,665	52,758,079	52,565,623	52,383,880	52,286,778	52,254,676	52,172,035	52,142,416	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		385,089	383,800	384,319	385,429	384,722	383,323	381,924	380,604	379,898	379,665	379,065	378,849	$4,586,687
	b. Debt Component Grossed Up For Taxes (C)		129,517	129,084	129,258	129,632	129,394	128,923	128,453	128,009	127,771	127,693	127,491	127,419	1,542,644
8.	Investment Expenses														
	a. Depreciation (D)		209,232	209,232	209,232	209,232	210,283	210,286	210,286	210,286	210,286	210,286	213,445	213,487	2,525,573
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		723,838	722,116	722,809	724,293	724,399	722,532	720,663	718,899	717,955	717,644	720,001	719,755	8,654,904
	a. Recoverable Costs Allocated to Energy		723,838	722,116	722,809	724,293	724,399	722,532	720,663	718,899	717,955	717,644	720,001	719,755	8,654,904
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		717,989	716,303	720,024	719,183	719,720	718,302	716,456	715,699	715,499	716,848	718,512	718,227	8,612,762
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$717,989	$716,303	$720,024	$719,183	$719,720	$718,302	$716,456	$715,699	$715,499	$716,848	$718,512	$718,227	$8,612,762

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2011 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(5,031,493)	(5,073,135)	(5,114,777)	(5,156,419)	(5,198,061)	(5,239,703)	(5,281,345)	(5,322,987)	(5,364,629)	(5,406,271)	(5,447,913)	(5,489,555)	(5,531,197)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$16,708,244	16,666,602	16,624,960	16,583,318	16,541,676	16,500,034	16,458,392	16,416,750	16,375,108	16,333,466	16,291,824	16,250,182	16,208,540	
6.	Average Net Investment		16,687,423	16,645,781	16,604,139	16,562,497	16,520,855	16,479,213	16,437,571	16,395,929	16,354,287	16,312,645	16,271,003	16,229,361	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		121,245	120,943	120,640	120,338	120,035	119,732	119,430	119,127	118,825	118,522	118,220	117,917	$1,434,974
	b. Debt Component Grossed Up For Taxes (C)		40,778	40,677	40,575	40,473	40,371	40,270	40,168	40,066	39,964	39,863	39,761	39,659	482,625
8.	Investment Expenses														
	a. Depreciation (D)		41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	499,704
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303
	a. Recoverable Costs Allocated to Energy		203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941529	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		202,019	201,626	202,075	201,025	200,743	200,464	200,065	199,941	199,745	199,805	199,210	198,795	2,405,513
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$202,019	$201,626	$202,075	$201,025	$200,743	$200,464	$200,065	$199,941	$199,745	$199,805	$199,210	$198,795	$2,405,513

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.5% and 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	2,705,295	2,696,956	2,688,617	2,680,278	2,671,939	2,663,600	2,655,261	2,646,922	2,638,583	2,630,244	2,621,905	2,613,566	2,605,227	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,896,147	5,887,808	5,879,469	5,871,130	5,862,791	5,854,452	5,846,113	5,837,774	5,829,435	5,821,096	5,812,757	5,804,418	5,796,079	
6.	Average Net Investment		5,891,978	5,883,639	5,875,300	5,866,961	5,858,622	5,850,283	5,841,944	5,833,605	5,825,266	5,816,927	5,808,588	5,800,249	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		42,809	42,749	42,688	42,627	42,567	42,506	42,446	42,385	42,324	42,264	42,203	42,143	$509,711
	b. Debt Component Grossed Up For Taxes (C)		14,398	14,378	14,357	14,337	14,317	14,296	14,276	14,255	14,235	14,215	14,194	14,174	171,432
8.	Investment Expenses														
	a. Depreciation (D)		8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	100,068
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		65,546	65,466	65,384	65,303	65,223	65,141	65,061	64,979	64,898	64,818	64,736	64,656	781,211
	a. Recoverable Costs Allocated to Energy		65,546	65,466	65,384	65,303	65,223	65,141	65,061	64,979	64,898	64,818	64,736	64,656	781,211
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		65,016	64,939	65,132	64,842	64,802	64,760	64,681	64,690	64,676	64,746	64,602	64,519	777,405
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$65,016	$64,939	$65,132	$64,842	$64,802	$64,760	$64,681	$64,690	$64,676	$64,746	$64,602	$64,519	$777,405

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$824	($79)	$0	$0	$143	$0	$0	$14,686	$7,909	$112,080	$14,804	$27,746	$178,112
	b. Clearings to Plant		824	(79)	0	0	143	0	0	0	0	0	0	0	888
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$8,516,877	$8,517,701	$8,517,622	$8,517,622	$8,517,622	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	
3.	Less: Accumulated Depreciation	(1,467,265)	(1,488,555)	(1,509,847)	(1,531,139)	(1,552,431)	(1,573,723)	(1,595,015)	(1,616,307)	(1,637,599)	(1,658,891)	(1,680,183)	(1,701,475)	(1,722,767)	
4.	CWIP - Non-Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	14,686	22,594	134,674	149,478	177,224	
5.	Net Investment (Lines 2 + 3 + 4)	$7,049,612	7,029,146	7,007,775	6,986,483	6,965,191	6,944,042	6,922,750	6,901,458	6,894,852	6,881,468	6,972,256	6,965,768	6,972,222	
6.	Average Net Investment		7,039,379	7,018,460	6,997,129	6,975,837	6,954,616	6,933,396	6,912,104	6,898,155	6,888,160	6,926,862	6,969,012	6,968,995	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		51,146	50,994	50,839	50,684	50,530	50,376	50,221	50,120	50,047	50,328	50,635	50,634	$606,554
	b. Debt Component Grossed Up For Taxes (C)		17,202	17,151	17,099	17,047	16,995	16,943	16,891	16,857	16,832	16,927	17,030	17,030	204,004
8.	Investment Expenses														
	a. Depreciation (D)		21,290	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	255,502
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		89,638	89,437	89,230	89,023	88,817	88,611	88,404	88,269	88,171	88,547	88,957	88,956	1,066,060
	a. Recoverable Costs Allocated to Energy		89,638	89,437	89,230	89,023	88,817	88,611	88,404	88,269	88,171	88,547	88,957	88,956	1,066,060
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		88,914	88,717	88,886	88,395	88,243	88,092	87,888	87,876	87,869	88,449	88,773	88,767	1,060,869
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$88,914	$88,717	$88,886	$88,395	$88,243	$88,092	$87,888	$87,876	$87,869	$88,449	$88,773	$88,767	$1,060,869

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($526,713)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, 2.1%, and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 120007-EI
ECRC 2011 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(364,794)	(369,218)	(373,642)	(378,066)	(382,490)	(386,914)	(391,338)	(395,762)	(400,186)	(404,610)	(409,034)	(413,458)	(417,882)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,196,679	1,192,255	1,187,831	1,183,407	1,178,983	1,174,559	1,170,135	1,165,711	1,161,287	1,156,863	1,152,439	1,148,015	1,143,591	
6.	Average Net Investment		1,194,467	1,190,043	1,185,619	1,181,195	1,176,771	1,172,347	1,167,923	1,163,499	1,159,075	1,154,651	1,150,227	1,145,803	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,679	8,646	8,614	8,582	8,550	8,518	8,486	8,454	8,421	8,389	8,357	8,325	$102,021
	b. Debt Component Grossed Up For Taxes (C)		2,919	2,908	2,897	2,886	2,876	2,865	2,854	2,843	2,832	2,822	2,811	2,800	34,313
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422
	a. Recoverable Costs Allocated to Energy		16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		15,893	15,849	15,874	15,780	15,748	15,714	15,672	15,651	15,623	15,618	15,560	15,516	188,498
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,893	$15,849	$15,874	$15,780	$15,748	$15,714	$15,672	$15,651	$15,623	$15,618	$15,560	$15,516	$188,498

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(387,446)	(392,563)	(397,680)	(402,797)	(407,914)	(413,031)	(418,148)	(423,265)	(428,382)	(433,499)	(438,616)	(443,733)	(448,850)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,171,284	2,166,167	2,161,050	2,155,933	2,150,816	2,145,699	2,140,582	2,135,465	2,130,348	2,125,231	2,120,114	2,114,997	2,109,880	
6.	Average Net Investment		2,168,726	2,163,609	2,158,492	2,153,375	2,148,258	2,143,141	2,138,024	2,132,907	2,127,790	2,122,673	2,117,556	2,112,439	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,757	15,720	15,683	15,646	15,609	15,571	15,534	15,497	15,460	15,423	15,385	15,348	$186,633
	b. Debt Component Grossed Up For Taxes (C)		5,300	5,287	5,275	5,262	5,250	5,237	5,225	5,212	5,200	5,187	5,175	5,162	62,772
8.	Investment Expenses														
	a. Depreciation (D)		5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	61,404
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809
	a. Recoverable Costs Allocated to Energy		26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		25,963	25,914	25,975	25,841	25,808	25,773	25,725	25,711	25,689	25,698	25,624	25,573	309,294
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$25,963	$25,914	$25,975	$25,841	$25,808	$25,773	$25,725	$25,711	$25,689	$25,698	$25,624	$25,573	$309,294

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(215,425)	(219,960)	(224,495)	(229,030)	(233,565)	(238,100)	(242,635)	(247,170)	(251,705)	(256,240)	(260,775)	(265,310)	(269,845)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,433,696	1,429,161	1,424,626	1,420,091	1,415,556	1,411,021	1,406,486	1,401,951	1,397,416	1,392,881	1,388,346	1,383,811	1,379,276	
6.	Average Net Investment		1,431,429	1,426,894	1,422,359	1,417,824	1,413,289	1,408,754	1,404,219	1,399,684	1,395,149	1,390,614	1,386,079	1,381,544	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,400	10,367	10,334	10,301	10,268	10,236	10,203	10,170	10,137	10,104	10,071	10,038	$122,629
	b. Debt Component Grossed Up For Taxes (C)		3,498	3,487	3,476	3,465	3,454	3,443	3,431	3,420	3,409	3,398	3,387	3,376	41,244
8.	Investment Expenses														
	a. Depreciation (D)		4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	54,420
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,433	18,389	18,345	18,301	18,257	18,214	18,169	18,125	18,081	18,037	17,993	17,949	218,293
	a. Recoverable Costs Allocated to Energy		18,433	18,389	18,345	18,301	18,257	18,214	18,169	18,125	18,081	18,037	17,993	17,949	218,293
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		18,284	18,241	18,274	18,172	18,139	18,107	18,063	18,044	18,019	18,017	17,956	17,911	217,227
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,284	$18,241	$18,274	$18,172	$18,139	$18,107	$18,063	$18,044	$18,019	$18,017	$17,956	$17,911	$217,227

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(194,132)	(198,219)	(202,306)	(206,393)	(210,480)	(214,567)	(218,654)	(222,741)	(226,828)	(230,915)	(235,002)	(239,089)	(243,176)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,387,755	1,383,668	1,379,581	1,375,494	1,371,407	1,367,320	1,363,233	1,359,146	1,355,059	1,350,972	1,346,885	1,342,798	1,338,711	
6.	Average Net Investment		1,385,712	1,381,625	1,377,538	1,373,451	1,369,364	1,365,277	1,361,190	1,357,103	1,353,016	1,348,929	1,344,842	1,340,755	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,068	10,038	10,009	9,979	9,949	9,920	9,890	9,860	9,831	9,801	9,771	9,741	$118,857
	b. Debt Component Grossed Up For Taxes (C)		3,386	3,376	3,366	3,356	3,346	3,336	3,326	3,316	3,306	3,296	3,286	3,276	39,972
8.	Investment Expenses														
	a. Depreciation (D)		4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	49,044
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873
	a. Recoverable Costs Allocated to Energy		17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		17,399	17,360	17,395	17,299	17,270	17,241	17,202	17,186	17,165	17,165	17,109	17,068	206,859
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,399	$17,360	$17,395	$17,299	$17,270	$17,241	$17,202	$17,186	$17,165	$17,165	$17,109	$17,068	$206,859

Notes:
(A) Applicable depreciable base for Big Bend, account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(189,926)	(195,731)	(201,536)	(207,341)	(213,146)	(218,951)	(224,756)	(230,561)	(236,366)	(242,171)	(247,976)	(253,781)	(259,586)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,516,581	2,510,776	2,504,971	2,499,166	2,493,361	2,487,556	2,481,751	2,475,946	2,470,141	2,464,336	2,458,531	2,452,726	2,446,921	
6.	Average Net Investment		2,513,679	2,507,874	2,502,069	2,496,264	2,490,459	2,484,654	2,478,849	2,473,044	2,467,239	2,461,434	2,455,629	2,449,824	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,264	18,221	18,179	18,137	18,095	18,053	18,010	17,968	17,926	17,884	17,842	17,800	$216,379
	b. Debt Component Grossed Up For Taxes (C)		6,143	6,128	6,114	6,100	6,086	6,072	6,057	6,043	6,029	6,015	6,001	5,987	72,775
8.	Investment Expenses														
	a. Depreciation (D)		5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	69,660
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814
	a. Recoverable Costs Allocated to Energy		30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		29,968	29,911	29,982	29,830	29,792	29,755	29,698	29,683	29,658	29,671	29,587	29,529	357,064
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$29,968	$29,911	$29,982	$29,830	$29,792	$29,755	$29,698	$29,683	$29,658	$29,671	$29,587	$29,529	$357,064

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6% and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$20,912	$4,969	$882	($793)	$12	$74,088	$2	$0	$0	$0	$0	$0	$100,071
	b. Clearings to Plant		6,059	2,301	(19)	124,210	12	74,088	2	0	0	0	0	0	206,652
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$83,892,660	$83,898,720	$83,901,021	$83,901,002	$84,025,211	$84,025,223	$84,099,311	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	
3.	Less: Accumulated Depreciation	(1,467,937)	(1,652,512)	(1,837,101)	(2,021,694)	(2,206,287)	(2,391,222)	(2,576,157)	(2,762,570)	(2,948,983)	(3,135,396)	(3,321,809)	(3,508,222)	(3,694,635)	
4.	CWIP - Non-Interest Bearing	106,581	121,434	124,102	125,003	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$82,531,304	82,367,642	82,188,022	82,004,311	81,818,924	81,634,001	81,523,154	81,336,744	81,150,331	80,963,918	80,777,505	80,591,092	80,404,679	
6.	Average Net Investment		82,449,473	82,277,832	82,096,167	81,911,618	81,726,463	81,578,578	81,429,949	81,243,537	81,057,124	80,870,711	80,684,298	80,497,885	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		599,050	597,803	596,483	595,143	593,797	592,723	591,643	590,288	588,934	587,580	586,225	584,871	$7,104,540
	b. Debt Component Grossed Up For Taxes (C)		201,479	201,060	200,616	200,165	199,712	199,351	198,988	198,532	198,077	197,621	197,166	196,710	2,389,477
8.	Investment Expenses														
	a. Depreciation (D)		184,575	184,589	184,593	184,593	184,935	184,935	186,413	186,413	186,413	186,413	186,413	186,413	2,226,698
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		985,104	983,452	981,692	979,901	978,444	977,009	977,044	975,233	973,424	971,614	969,804	967,994	11,720,715
	a. Recoverable Costs Allocated to Energy		985,104	983,452	981,692	979,901	978,444	977,009	977,044	975,233	973,424	971,614	969,804	967,994	11,720,715
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		977,144	975,535	977,910	972,988	972,124	971,289	971,341	970,892	970,094	970,537	967,798	965,939	11,663,591
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$977,144	$975,535	$977,910	$972,988	$972,124	$971,289	$971,341	$970,892	$970,094	$970,537	$967,798	$965,939	$11,663,591

Notes:

(A) Applicable depreciable base for Big Bend; account 311.41 ($25,152,322), 312.41 ($52,950,344), 315.41 ($5,040,181), and 316.41 ($956,467).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 1.4%, 3.3%, 2.5% and 1.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$14,853	$2,668	$901	$0	$0	$0	$55,541	$103	$192,159	$348,553	$356,447	$264,147	$1,235,371
	b. Clearings to Plant		0	0	0	125,003	0	0	0	0	0	0	696,497	8,238	829,737
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$91,495,521	$91,495,521	$91,495,521	$91,495,521	$91,620,524	$91,620,524	$91,620,524	$91,620,524	$91,620,524	$91,620,524	$91,620,524	$92,317,021	$92,325,259	
3.	Less: Accumulated Depreciation	(3,058,932)	(3,254,949)	(3,450,966)	(3,646,983)	(3,843,000)	(4,039,340)	(4,235,680)	(4,432,020)	(4,628,360)	(4,824,700)	(5,021,040)	(5,217,380)	(5,415,519)	
4.	CWIP - Non-Interest Bearing	106,581	121,434	124,102	125,003	(0)	(0)	(0)	55,541	55,643	247,802	596,355	256,306	512,215	
5.	Net Investment (Lines 2 + 3 + 4)	$88,543,170	88,362,006	88,168,657	87,973,541	87,777,524	87,581,184	87,384,844	87,244,045	87,047,807	87,043,627	87,195,839	87,355,946	87,421,955	
6.	Average Net Investment		88,452,588	88,265,332	88,071,099	87,875,533	87,679,354	87,483,014	87,314,445	87,145,926	87,045,717	87,119,733	87,275,893	87,388,951	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		642,667	641,306	639,895	638,474	637,049	635,622	634,398	633,173	632,445	632,983	634,118	634,939	$7,637,069
	b. Debt Component Grossed Up For Taxes (C)		216,149	215,691	215,216	214,739	214,259	213,779	213,367	212,956	212,711	212,892	213,273	213,549	2,568,581
8.	Investment Expenses														
	a. Depreciation (D)		196,017	196,017	196,017	196,017	196,340	196,340	196,340	196,340	196,340	196,340	196,340	198,139	2,356,587
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,054,833	1,053,014	1,051,128	1,049,230	1,047,648	1,045,741	1,044,105	1,042,469	1,041,496	1,042,215	1,043,731	1,046,627	12,562,237
	a. Recoverable Costs Allocated to Energy		1,054,833	1,053,014	1,051,128	1,049,230	1,047,648	1,045,741	1,044,105	1,042,469	1,041,496	1,042,215	1,043,731	1,046,627	12,562,237
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		1,046,310	1,044,537	1,047,078	1,041,828	1,040,881	1,039,619	1,038,010	1,037,829	1,037,933	1,041,060	1,041,572	1,044,405	12,501,062
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,046,310	$1,044,537	$1,047,078	$1,041,828	$1,040,881	$1,039,619	$1,038,010	$1,037,829	$1,037,933	$1,041,060	$1,041,572	$1,044,405	$12,501,062

Notes:

(A) Applicable depreciable base for Big Bend; account 311.42 ($25,208,869), 312.42 ($50,243,347), 315.42 ($15,914,427), and 316.42 ($958,616).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.6%, 3.1%, 2.5% and 2.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$333	$511,969	$499,292	$45,035	$1,120	$390	$0	$0	$0	$4,144	($4,144)	$4,144	$1,062,283
	b. Clearings to Plant		0	0	0	1,442,662	1,120	390	0	0	0	4,144	(4,144)	4,144	1,448,317
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$78,714,882	$78,714,882	$78,714,882	$78,714,882	$80,157,544	$80,158,664	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,163,199	$80,159,055	$80,163,199	
3.	Less: Accumulated Depreciation	(4,645,109)	(4,789,282)	(4,933,455)	(5,077,628)	(5,221,801)	(5,369,099)	(5,516,400)	(5,663,702)	(5,811,004)	(5,958,306)	(6,105,608)	(6,252,919)	(6,400,221)	
4.	CWIP - Non-Interest Bearing	386,034	386,366	898,335	1,397,627	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$74,455,806	74,311,966	74,679,762	75,034,881	74,935,743	74,789,565	74,642,655	74,495,353	74,348,051	74,200,749	74,057,591	73,906,136	73,762,978	
6.	Average Net Investment		74,383,886	74,495,864	74,857,322	74,985,312	74,862,654	74,716,110	74,569,004	74,421,702	74,274,400	74,129,170	73,981,863	73,834,557	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		540,449	541,262	543,888	544,818	543,927	542,862	541,794	540,723	539,653	538,598	537,528	536,457	$6,491,959
	b. Debt Component Grossed Up For Taxes (C)		181,769	182,043	182,926	183,239	182,939	182,581	182,222	181,862	181,502	181,147	180,787	180,427	2,183,444
8.	Investment Expenses														
	a. Depreciation (D)		144,173	144,173	144,173	144,173	147,298	147,301	147,302	147,302	147,302	147,302	147,311	147,302	1,755,112
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		866,391	867,478	870,987	872,230	874,164	872,744	871,318	869,887	868,457	867,047	865,626	864,186	10,430,515
	a. Recoverable Costs Allocated to Energy		866,391	867,478	870,987	872,230	874,164	872,744	871,318	869,887	868,457	867,047	865,626	864,186	10,430,515
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		859,390	860,495	867,631	866,076	868,518	867,635	866,232	866,015	865,486	866,086	863,836	862,351	10,379,751
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$859,390	$860,495	$867,631	$866,076	$868,518	$867,635	$866,232	$866,015	$865,486	$866,086	$863,836	$862,351	$10,379,751

Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($21,689,422), 312.43 ($43,958,139), 315.43 ($13,690,954), and 316.43 ($824,684).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.2%, 2.6%, 2.5%, and 2.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	
3.	Less: Accumulated Depreciation	(5,145,308)	(5,253,906)	(5,362,504)	(5,471,102)	(5,579,700)	(5,688,298)	(5,796,896)	(5,905,494)	(6,014,092)	(6,122,690)	(6,231,288)	(6,339,886)	(6,448,484)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$57,707,725	57,599,127	57,490,529	57,381,931	57,273,333	57,164,735	57,056,137	56,947,539	56,838,941	56,730,343	56,621,745	56,513,147	56,404,549	
6.	Average Net Investment		57,653,426	57,544,828	57,436,230	57,327,632	57,219,034	57,110,436	57,001,838	56,893,240	56,784,642	56,676,044	56,567,446	56,458,848	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		418,891	418,102	417,313	416,523	415,734	414,945	414,156	413,367	412,578	411,789	411,000	410,211	$4,974,609
	b. Debt Component Grossed Up For Taxes (C)		140,886	140,620	140,355	140,090	139,824	139,559	139,293	139,028	138,763	138,497	138,232	137,967	1,673,114
8.	Investment Expenses														
	a. Depreciation (D)		108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	1,303,176
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		668,375	667,320	666,266	665,211	664,156	663,102	662,047	660,993	659,939	658,884	657,830	656,776	7,950,899
	a. Recoverable Costs Allocated to Energy		668,375	667,320	666,266	665,211	664,156	663,102	662,047	660,993	659,939	658,884	657,830	656,776	7,950,899
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		662,974	661,948	663,699	660,518	659,866	659,220	658,183	658,051	657,681	658,154	656,470	655,382	7,912,146
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$662,974	$661,948	$663,699	$660,518	$659,866	$659,220	$658,183	$658,051	$657,681	$658,154	$656,470	$655,382	$7,912,146

Notes:
(A) Applicable depreciable base for Big Bend; account 311.44 ($16,857,250), 312.44 ($34,665,822), 315.44 ($10,642,027), and 316.44 ($687,934).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 1.4%, 2.4%, 2.1%, and 1.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$442,854	$93,805	$49,879	$84,367	$420,821	$1,144,115	$1,112,743	$589,367	$1,042,670	$2,045,769	$7,026,389
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	
3.	Less: Accumulated Depreciation	(828,433)	(850,722)	(873,011)	(895,300)	(917,589)	(939,878)	(962,167)	(984,456)	(1,006,745)	(1,029,034)	(1,051,323)	(1,073,612)	(1,095,901)	
4.	CWIP - Non-Interest Bearing	0	0	0	442,854	536,659	586,538	670,905	1,091,726	2,235,840	3,348,584	3,937,951	4,980,621	7,026,389	
5.	Net Investment (Lines 2 + 3 + 4)	$10,737,596	10,715,307	10,693,018	11,113,582	11,185,099	11,212,689	11,274,767	11,673,298	12,795,124	13,885,578	14,452,656	15,473,037	17,496,517	
6.	Average Net Investment		10,726,451	10,704,162	10,903,300	11,149,340	11,198,894	11,243,728	11,474,033	12,234,211	13,340,351	14,169,117	14,962,847	16,484,777	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		77,935	77,773	79,220	81,007	81,367	81,693	83,366	88,890	96,927	102,948	108,715	119,773	$1,079,614
	b. Debt Component Grossed Up For Taxes (C)		26,212	26,157	26,644	27,245	27,366	27,476	28,039	29,896	32,599	34,625	36,564	40,283	363,106
8.	Investment Expenses														
	a. Depreciation (D)		22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	267,468
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		126,436	126,219	128,153	130,541	131,022	131,458	133,694	141,075	151,815	159,862	167,568	182,345	1,710,188
	a. Recoverable Costs Allocated to Energy		126,436	126,219	128,153	130,541	131,022	131,458	133,694	141,075	151,815	159,862	167,568	182,345	1,710,188
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		125,414	125,203	127,659	129,620	130,176	130,688	132,914	140,447	151,296	159,685	167,221	181,958	1,702,281
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$125,414	$125,203	$127,659	$129,620	$130,176	$130,688	$132,914	$140,447	$151,296	$159,685	$167,221	$181,958	$1,702,281

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($10,109,820)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4% and 2.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$22,458	$0	$0	$0	$0	$0	$0	$0	$52,300	$74,758
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	
3.	Less: Accumulated Depreciation	(57,348)	(60,271)	(63,194)	(66,117)	(69,040)	(71,963)	(74,886)	(77,809)	(80,732)	(83,655)	(86,578)	(89,501)	(92,424)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	22,458	22,458	22,458	22,458	22,458	22,458	22,458	22,458	74,758	
5.	Net Investment (Lines 2 + 3 + 4)	$1,111,705	1,108,782	1,105,859	1,102,936	1,122,471	1,119,548	1,116,625	1,113,702	1,110,779	1,107,856	1,104,933	1,102,010	1,151,387	
6.	Average Net Investment		1,110,244	1,107,321	1,104,398	1,112,704	1,121,010	1,118,087	1,115,164	1,112,241	1,109,318	1,106,395	1,103,472	1,126,699	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,067	8,045	8,024	8,085	8,145	8,124	8,102	8,081	8,060	8,039	8,017	8,186	$96,975
	b. Debt Component Grossed Up For Taxes (C)		2,713	2,706	2,699	2,719	2,739	2,732	2,725	2,718	2,711	2,704	2,697	2,753	32,616
8.	Investment Expenses														
	a. Depreciation (D)		2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	35,076
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		13,703	13,674	13,646	13,727	13,807	13,779	13,750	13,722	13,694	13,666	13,637	13,862	164,667
	a. Recoverable Costs Allocated to Energy		13,703	13,674	13,646	13,727	13,807	13,779	13,750	13,722	13,694	13,666	13,637	13,862	164,667
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		13,592	13,564	13,593	13,630	13,718	13,698	13,670	13,661	13,647	13,651	13,609	13,833	163,866
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,592	$13,564	$13,593	$13,630	$13,718	$13,698	$13,670	$13,661	$13,647	$13,651	$13,609	$13,833	$163,866

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 345.81, and 315.40 ($1,169,053)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%, 3.3%, 2.6%, 2.4% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		$0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	3,604	0	0	0	0	0	0	0	0	3,604
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(39,823)	(39,686)	(39,577)	(39,481)	(39,348)	(39,244)	(39,126)	(39,021)	(38,882)	(38,782)	(38,677)	(38,566)	(38,451)	
3.	Total Working Capital Balance	($39,823)	(39,686)	(39,577)	(39,481)	(39,348)	(39,244)	(39,126)	(39,021)	(38,882)	(38,782)	(38,677)	(38,566)	(38,451)	
4.	Average Net Working Capital Balance		($39,754)	($39,631)	($39,529)	($39,415)	($39,296)	($39,185)	($39,074)	($38,951)	($38,832)	($38,730)	($38,622)	($38,509)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(289)	(288)	(287)	(286)	(286)	(285)	(284)	(283)	(282)	(281)	(281)	(280)	(3,412)
	b. Debt Component Grossed Up For Taxes (B)		(97)	(97)	(97)	(96)	(96)	(96)	(95)	(95)	(95)	(95)	(94)	(94)	(1,147)
6.	Total Return Component		(386)	(385)	(384)	(382)	(382)	(381)	(379)	(378)	(377)	(376)	(375)	(374)	(4,559)
7.	Expenses:														
	a. Gains		0	0	0	(3,604)	0	0	0	0	0	0	0	0	(3,604)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		1,750	328	2,030	4,795	4,640	3,328	2,821	1,124	326	(119)	(140)	(105)	20,778
8.	Net Expenses (D)		1,750	328	2,030	1,191	4,640	3,328	2,821	1,124	326	(119)	(140)	(105)	17,174
9.	Total System Recoverable Expenses (Lines 6 + 8)		1,364	(57)	1,646	809	4,258	2,947	2,442	746	(51)	(495)	(515)	(479)	12,615
	a. Recoverable Costs Allocated to Energy		1,364	(57)	1,646	809	4,258	2,947	2,442	746	(51)	(495)	(515)	(479)	12,615
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9941629	0.9955490	0.9965789	0.9988915	0.9979319	0.9978769	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		1,353	(57)	1,640	803	4,230	2,930	2,428	743	(51)	(494)	(514)	(478)	12,533
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		$1,353	($57)	$1,640	$803	$4,230	$2,930	$2,428	$743	($51)	($494)	($514)	($478)	$12,533

Notes:

(A) Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(B) Line 4 x 2.9324% x 1/12.
(C) Line 6 is reported on Schedules 6E and 7A
(D) Line 8 is reported on Schedules 4E and 5A
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

[1] Subject to Baseline Analytics

DOCKET NO. 120007-EI
ECRC 2011 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 26 OF 26

Form 42 - 9A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2011 to December 2011

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base 2009 Test Year ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,384,999	40.29%	6.80%	2.7397%
Short Term Debt	7,905	0.23%	2.75%	0.0063%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	99,502	2.89%	6.07%	0.1754%
Common Equity	1,632,612	47.49%	11.25%	5.3426%
Deferred ITC - Weighted Cost	8,964	0.26%	9.19%	0.0239%
Accumulated Deferred Income Taxes - Zero Cost ITCs	303,629	8.83%	0.00%	0.0000%
Total	$ 3,437,611	100.00%		8.2879%

ITC split between Debt and Equity:

Long Term Debt	$ 1,384,999	Long Term Debt	45.78%
Short Term Debt	7,905	Short Term Debt	0.26%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,632,612	Equity - Common	53.96%
Total	$ 3,025,516	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0239% * 46.04%	0.0110%
Equity = .0239% * 53.96%	0.0129%
Weighted Cost	0.0239%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	5.3426%
Deferred ITC - Weighted Cost	0.0129%
	5.3555%
Times Tax Multiplier	1.628002
Total Equity Component	8.7188%

Total Debt Cost Rate:

Long Term Debt	2.7397%
Short Term Debt	0.0063%
Customer Deposits	0.1754%
Deferred ITC - Weighted Cost	0.0110%
Total Debt Component	2.9324%

Notes:
Column (1) - From Order No. PSC-09-0571-FOF-EI
Column (2) - Column (1) / Total Column (1)
Column (3) - From Order No. PSC-09-0571-FOF-EI
Column (4) - Column (2) x Column (3)

INDEX

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL / ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD OF
JANUARY 2012 THROUGH DECEMBER 2012

FORMS 42-1E THROUGH 42-9E

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 33
PARTY Tampa Electric Company
DESCRIPTION Howard T. Bryant (HTB-2), ECRC Forms
DATE 42-9E for 1/12-12/12

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2012 to December 2012
(in Dollars)

Form 42 - 1E

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($11,751,882)
2.	Interest Provision (Form 42-2E, Line 6)	(21,613)
3.	Sum of Current Period Adjustments (Form 42-2E, Line 10)	18,669
4.	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2013 to December 2013 (Lines 1 + 2 + 3)	($11,754,826)

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DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 1, PAGE 1 OF 1

Form 42 - 2E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	ECRC Revenues (net of Revenue Taxes)	$6,434,215	$5,934,263	$5,990,668	$6,814,704	$6,925,467	$7,922,515	$8,476,134	$8,536,942	$8,639,291	$7,735,063	$6,636,777	$6,545,380	$86,591,418
2.	True-Up Provision	(256,742)	(256,742)	(256,742)	(256,742)	(256,742)	(256,742)	(256,742)	(256,742)	(256,742)	(256,742)	(256,742)	(256,736)	(3,080,898)
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	6,177,473	5,677,521	5,733,926	6,557,962	6,668,725	7,665,773	8,219,392	8,280,200	8,382,549	7,478,321	6,380,035	6,288,644	83,510,520
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	1,292,940	2,075,962	1,978,566	1,733,652	1,655,344	1,572,756	3,333,681	3,318,717	3,419,074	3,265,993	3,383,866	3,673,951	30,704,502
	b. Capital Investment Projects (Form 42-7E, Line 9)	5,555,377	5,474,270	5,473,360	5,409,904	5,342,611	5,340,409	5,326,611	5,338,952	5,333,122	5,325,217	5,321,458	5,316,610	64,557,901
	c. Total Jurisdictional ECRC Costs	6,848,317	7,550,232	7,451,926	7,143,556	6,997,955	6,913,165	8,660,292	8,657,669	8,752,196	8,591,210	8,705,324	8,990,561	95,262,403
5.	Over/Under Recovery (Line 3 - Line 4c)	(670,844)	(1,872,711)	(1,718,000)	(585,594)	(329,230)	752,608	(440,900)	(377,469)	(369,647)	(1,112,889)	(2,325,289)	(2,701,917)	(11,751,882)
6.	Interest Provision (Form 42-3E, Line 10)	(390)	(752)	(725)	(896)	(1,015)	(969)	(1,669)	(2,640)	(2,674)	(2,810)	(3,220)	(3,853)	(21,613)
7.	Beginning Balance True-Up & Interest Provision	(3,080,898)	(3,476,721)	(5,093,442)	(6,555,425)	(6,885,173)	(6,958,676)	(5,950,295)	(6,136,122)	(6,259,489)	(6,375,068)	(7,234,025)	(9,305,792)	(3,080,898)
	a. Deferred True-Up from January to December 2011 (Order No. PSC-xx-xxxx-FOF-EI)	**(3,232,451)**	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)	(3,232,451)
8.	True-Up Collected/(Refunded) (see Line 2)	256,742	256,742	256,742	256,742	256,742	256,742	256,742	256,742	256,742	256,742	256,742	256,736	3,080,898
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	(6,727,841)	(8,325,893)	(9,787,876)	(10,117,624)	(10,191,127)	(9,182,746)	(9,368,573)	(9,491,940)	(9,607,519)	(10,466,476)	(12,538,243)	(14,987,277)	(15,005,946)
10.	Adjustment to Period True-Up Including Interest	18,669	0	0	0	0	0	0	0	0	0	0	0	18,669
11.	End of Period Total True-Up (Lines 9 + 10)	($6,709,172)	($8,325,893)	($9,787,876)	($10,117,624)	($10,191,127)	($9,182,746)	($9,368,573)	($9,491,940)	($9,607,519)	($10,466,476)	($12,538,243)	($14,987,277)	($14,987,277)

DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 2, PAGE 1 OF 1

Form 42 - 3E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	($6,294,680)	($6,709,172)	($8,325,893)	($9,787,876)	($10,117,624)	($10,191,127)	($9,182,746)	($9,368,573)	($9,491,940)	($9,607,519)	($10,466,476)	($12,538,243)	
2.	Ending True-Up Amount Before Interest	(6,708,782)	(8,325,141)	(9,787,151)	(10,116,728)	(10,190,112)	(9,181,777)	(9,366,904)	(9,489,300)	(9,604,845)	(10,463,666)	(12,535,023)	(14,983,424)	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	(13,003,462)	(15,034,313)	(18,113,044)	(19,904,604)	(20,307,736)	(19,372,904)	(18,549,650)	(18,857,873)	(19,096,785)	(20,071,185)	(23,001,499)	(27,521,667)	
4.	Average True-Up Amount (Line 3 x 1/2)	(6,501,731)	(7,517,157)	(9,056,522)	(9,952,302)	(10,153,868)	(9,686,452)	(9,274,825)	(9,428,937)	(9,548,393)	(10,035,593)	(11,500,750)	(13,760,834)	
5.	Interest Rate (First Day of Reporting Business Month)	0.03%	0.12%	0.11%	0.09%	0.12%	0.13%	0.10%	0.33%	0.33%	0.33%	0.33%	0.33%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.12%	0.11%	0.09%	0.12%	0.13%	0.10%	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.15%	0.23%	0.20%	0.21%	0.25%	0.23%	0.43%	0.66%	0.66%	0.66%	0.66%	0.66%	
8.	Average Interest Rate (Line 7 x 1/2)	0.075%	0.115%	0.100%	0.105%	0.125%	0.115%	0.215%	0.330%	0.330%	0.330%	0.330%	0.330%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.006%	0.010%	0.008%	0.009%	0.010%	0.010%	0.018%	0.028%	0.028%	0.028%	0.028%	0.028%	
10.	Interest Provision for the Month (Line 4 x Line 9)	($390)	($752)	($725)	($896)	($1,015)	($969)	($1,669)	($2,640)	($2,674)	($2,810)	($3,220)	($3,853)	($21,613)

DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 3, PAGE 1 OF 1

Tampa Electric Company Form 42 - 4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual/Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$4,562,661	$4,490,200	$72,461	1.6%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	9,959	22,262	(12,303)	-55.3%
	d. Big Bend Units 1 & 2 FGD	17,606,161	$8,835,100	8,771,061	99.3%
	e. Big Bend PM Minimization and Monitoring	395,718	$390,400	5,318	1.4%
	f. Big Bend NO_x Emissions Reduction	380,422	$395,000	(14,578)	-3.7%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	0	20,000	(20,000)	-100.0%
	i. Polk NO_x Emissions Reduction	16,336	$35,000	(18,664)	-53.3%
	j. Bayside SCR Consumables	121,844	$106,400	15,444	14.5%
	k. Big Bend Unit 4 SOFA	0	0	0	0.0%
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0.0%
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0.0%
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	56,140	30,000	26,140	87.1%
	p. Arsenic Groundwater Standard Program	84,499	667,000	(582,501)	-87.3%
	q. Big Bend 1 SCR	2,300,371	2,466,489	(166,118)	-6.7%
	r. Big Bend 2 SCR	2,328,275	2,536,432	(208,157)	-8.2%
	s. Big Bend 3 SCR	1,868,922	1,513,033	355,889	23.5%
	t. Big Bend 4 SCR	868,068	998,269	(130,201)	-13.0%
	u. Clean Air Mercury Rule	25,401	24,000	1,401	5.8%
	v. Greenhouse Gas Reduction Program	90,788	40,000	50,788	127.0%
2.	Total Investment Projects - Recoverable Costs	$30,750,065	$22,604,085	$8,145,980	36.0%
3.	Recoverable Costs Allocated to Energy	$30,574,926	$21,852,585	$8,722,341	39.9%
4.	Recoverable Costs Allocated to Demand	$175,139	$751,500	($576,361)	-76.7%

Notes:

Column (1) is the End of Period Totals on Form 42-5E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Form 42 - 5E

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$279,997	$392,169	$497,890	$255,035	$500,709	$370,661	$362,700	$362,700	$452,700	$362,700	$362,700	$362,700	$4,562,661		$4,562,661
b.	Big Bend Units 1 & 2 Flue Gas Conditioning													0		0
c.	SO_2 Emissions Allowances	(43)	(114)	(114)	(1,051)	(45)	(60)	1,888	1,887	1,902	1,911	1,898	1,900	9,959		9,959
d.	Big Bend Units 1 & 2 FGD	540,951	787,656	731,659	769,873	696,915	704,907	2,195,700	2,195,700	2,195,700	2,195,700	2,195,700	2,395,700	17,606,161		17,606,161
e.	Big Bend PM Minimization and Monitoring	50,208	36,899	27,901	46,522	25,331	(12,932)	36,965	36,965	36,965	36,965	36,965	36,965	395,718		395,718
f.	Big Bend NO_x Emissions Reduction	24,370	1,688	(2,718)	35,148	38,520	13,365	25,048	25,000	25,000	25,000	85,000	85,000	380,422		380,422
g.	NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
h.	Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
i.	Polk NO_x Reduction	3	0	371	175	786	0	2,500	2,500	2,500	2,500	2,500	2,500	16,336		16,336
j.	Bayside SCR and Ammonia	14,436	0	10,730	12,132	12,660	14,387	11,500	11,500	11,500	11,500	0	11,500	121,844		121,844
k.	Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
l.	Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
m.	Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
n.	Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
o.	Clean Water Act Section 316(b) Phase II Study	(2,579)	0	7,168	23,711	6,840	0	3,500	3,500	3,500	3,500	3,500	3,500	56,140	56,140	
p.	Arsenic Groundwater Standard Program	0	3,867	26,506	26,895	7,232	0	10,000	0	0	10,000	0	0	84,499	84,499	
q.	Big Bend 1 SCR	192,689	261,522	253,634	50,423	12,328	123,489	229,089	231,978	253,881	208,149	234,915	248,274	2,300,371		2,300,371
r.	Big Bend 2 SCR	223,567	240,818	190,525	173,538	126,410	163,321	205,760	196,648	214,902	178,795	199,098	216,894	2,328,275		2,328,275
s.	Big Bend 3 SCR	145,796	155,541	138,730	219,455	148,941	111,544	159,393	161,319	126,288	145,435	163,281	193,200	1,868,922		1,868,922
t.	Big Bend 4 SCR	(217,727)	109,495	99,756	123,082	80,101	86,418	94,696	95,659	98,141	87,714	96,634	114,100	868,068		868,068
u.	Clean Air Mercury Rule	9,393	533	0	1,858	1,617	0	2,000	2,000	2,000	2,000	2,000	2,000	25,401		25,401
v.	Greenhouse Gas Reduction Program	0	90,000	788	0	0	0	0	0	0	0	0	0	90,788		90,788
2.	Total of O&M Activities	1,295,561	2,080,072	1,982,826	1,736,795	1,658,346	1,575,099	3,340,739	3,327,356	3,424,979	3,269,869	3,384,191	3,674,233	30,750,065	$175,139	$30,574,926
3.	Recoverable Costs Allocated to Energy	1,263,640	2,076,205	1,949,152	1,686,190	1,644,274	1,575,099	3,327,239	3,323,856	3,421,479	3,256,369	3,380,691	3,670,733	30,574,926		
4.	Recoverable Costs Allocated to Demand	31,921	3,867	33,674	50,605	14,072	0	13,500	3,500	3,500	13,500	3,500	3,500	175,139		
5.	Retail Energy Jurisdictional Factor	0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272			
6.	Retail Demand Jurisdictional Factor	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152			
7.	Jurisdictional Energy Recoverable Costs (A)	1,261,153	2,072,111	1,945,033	1,683,259	1,641,331	1,572,756	3,320,237	3,315,232	3,415,589	3,252,549	3,380,381	3,670,466	30,530,097		
8.	Jurisdictional Demand Recoverable Costs (B)	31,787	3,851	33,533	50,393	14,013	0	13,444	3,485	3,485	13,444	3,485	3,485	174,405		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,292,940	$2,075,962	$1,978,566	$1,733,652	$1,655,344	$1,572,756	$3,333,681	$3,318,717	$3,419,074	$3,265,993	$3,383,866	$3,673,951	$30,704,502		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 5, PAGE 1 OF 1

Tampa Electric Company Form 42 - 6E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line		(1) Actual/Estimated	(2) Original Projection	(3) Variance Amount	(4) Percent
1.	Description of Investment Projects				
a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$735,696	$768,402	($32,706)	-4.3%
b.	Big Bend Units 1 & 2 Flue Gas Conditioning	415,503	384,629	30,874	8.0%
c.	Big Bend Unit 4 Continuous Emissions Monitors	83,239	74,263	8,976	12.1%
d.	Big Bend Fuel Oil Tank # 1 Upgrade	53,818	50,065	3,753	7.5%
e.	Big Bend Fuel Oil Tank # 2 Upgrade	88,515	82,344	6,171	7.5%
f.	Phillips Upgrade Tank # 1 for FDEP	31,318	5,267	26,051	494.6%
g.	Phillips Upgrade Tank # 4 for FDEP	49,049	8,267	40,782	493.3%
h.	Big Bend Unit 1 Classifier Replacement	132,351	123,674	8,677	7.0%
i.	Big Bend Unit 2 Classifier Replacement	95,423	89,861	5,562	6.2%
j.	Big Bend Section 114 Mercury Testing Platform	13,770	12,739	1,031	8.1%
k.	Big Bend Units 1 & 2 FGD	8,843,462	8,815,500	27,962	0.3%
l.	Big Bend FGD Optimization and Utilization	2,400,129	2,359,083	41,046	1.7%
m.	Big Bend NO_x Emissions Reduction	790,395	769,550	20,845	2.7%
n.	Big Bend PM Minimization and Monitoring	1,101,472	1,076,352	25,120	2.3%
o.	Polk NO_x Emissions Reduction	183,237	183,237	0	0.0%
p.	Big Bend Unit 4 SOFA	318,119	303,655	14,464	4.8%
q.	Big Bend Unit 1 Pre-SCR	222,824	211,950	10,874	5.1%
r.	Big Bend Unit 2 Pre-SCR	211,090	202,159	8,931	4.4%
s.	Big Bend Unit 3 Pre-SCR	374,972	350,697	24,275	6.9%
t.	Big Bend Unit 1 SCR	12,544,301	11,474,749	1,069,552	9.3%
u.	Big Bend Unit 2 SCR	13,355,306	12,505,318	849,988	6.8%
v.	Big Bend Unit 3 SCR	11,105,329	10,258,438	846,891	8.3%
w.	Big Bend Unit 4 SCR	8,363,075	7,799,065	564,010	7.2%
x.	Big Bend FGD System Reliability	2,977,349	3,473,539	(496,190)	-14.3%
y.	Clean Air Mercury Rule	174,891	166,916	7,975	4.8%
z.	SO_2 Emissions Allowances	(4,419)	(4,391)	(28)	0.6%
2.	Total Investment Projects - Recoverable Costs	$64,660,214	$61,545,328	$3,114,886	5.1%
3.	Recoverable Costs Allocated to Energy	$64,437,514	$61,399,385	$3,038,129	4.9%
4.	Recoverable Costs Allocated to Demand	$222,700	$145,943	$76,757	52.6%

Notes:

Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Form 42-7E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$62,224	$62,057	$61,892	$61,725	$61,558	$61,392	$61,225	$61,058	$60,891	$60,725	$60,558	$60,391	$735,696		$735,696
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	35,487	35,331	35,174	35,017	34,860	34,704	34,546	34,390	34,234	34,077	33,920	33,763	415,503		415,503
	c.	Big Bend Unit 4 Continuous Emissions Monitors	7,059	7,038	7,015	6,993	6,970	6,948	6,926	6,903	6,880	6,858	6,836	6,813	83,239		83,239
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,560	4,546	4,533	4,519	4,505	4,492	4,478	4,465	4,450	4,437	4,423	4,410	53,818	$ 53,818	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,500	7,477	7,455	7,433	7,410	7,388	7,365	7,342	7,320	7,297	7,275	7,253	88,515	88,515	
	f.	Phillips Upgrade Tank # 1 for FDEP	31,318	0	0	0	0	0	0	0	0	0	0	0	31,318	31,318	
	g.	Phillips Upgrade Tank # 4 for FDEP	49,049	0	0	0	0	0	0	0	0	0	0	0	49,049	49,049	
	h.	Big Bend Unit 1 Classifier Replacement	11,263	11,221	11,178	11,136	11,094	11,051	11,008	10,965	10,923	10,880	10,837	10,795	132,351		132,351
	i.	Big Bend Unit 2 Classifier Replacement	8,114	8,085	8,055	8,026	7,996	7,967	7,938	7,908	7,878	7,848	7,819	7,789	95,423		95,423
	j.	Big Bend Section 114 Mercury Testing Platform	1,163	1,161	1,158	1,154	1,151	1,149	1,146	1,143	1,141	1,138	1,135	1,131	13,770		13,770
	k.	Big Bend Units 1 & 2 FGD	742,690	740,128	738,811	738,287	739,416	741,944	739,483	737,150	734,831	732,479	730,096	728,147	8,843,462		8,843,462
	l.	Big Bend FGD Optimization and Utilization	202,428	201,988	201,549	201,110	200,670	200,231	199,791	199,352	198,912	198,472	198,033	197,593	2,400,129		2,400,129
	m.	Big Bend NO_x Emissions Reduction	66,410	66,311	66,212	66,114	66,015	65,916	65,817	65,718	65,619	65,520	65,421	65,322	790,395		790,395
	n.	Big Bend PM Minimization and Monitoring	92,137	91,890	91,650	91,394	91,139	90,884	90,629	90,427	90,273	90,210	91,857	98,982	1,101,472		1,101,472
	o.	Polk NO_x Emissions Reduction	15,506	15,463	15,421	15,377	15,334	15,291	15,248	15,205	15,163	15,120	15,076	15,033	183,237		183,237
	p.	Big Bend Unit 4 SOFA	26,851	26,789	26,727	26,665	26,604	26,541	26,479	26,417	26,355	26,292	26,231	26,168	318,119		318,119
	q.	Big Bend Unit 1 Pre-SCR	18,862	18,808	18,756	18,702	18,649	18,596	18,542	18,489	18,435	18,382	18,328	18,275	222,824		222,824
	r.	Big Bend Unit 2 Pre-SCR	17,851	17,803	17,757	17,710	17,662	17,615	17,567	17,520	17,472	17,425	17,378	17,330	211,090		211,090
	s.	Big Bend Unit 3 Pre-SCR	31,673	31,595	31,518	31,440	31,363	31,287	31,209	31,132	31,054	30,978	30,900	30,823	374,972		374,972
	t.	Big Bend Unit 1 SCR	1,082,639	1,079,694	1,076,749	1,058,922	1,041,097	1,038,150	1,035,205	1,032,260	1,029,314	1,026,369	1,023,424	1,020,478	12,544,301		12,544,301
	u.	Big Bend Unit 2 SCR	1,145,697	1,142,804	1,143,659	1,127,987	1,108,686	1,106,047	1,103,285	1,100,389	1,097,492	1,094,595	1,093,087	1,091,578	13,355,306		13,355,306
	v.	Big Bend Unit 3 SCR	963,647	961,328	958,943	938,693	918,440	916,047	913,660	911,357	909,130	906,974	904,747	902,363	11,105,329		11,105,329
	w.	Big Bend Unit 4 SCR	726,745	724,997	723,250	707,236	691,221	689,475	687,727	685,979	684,232	682,485	680,738	678,990	8,363,075		8,363,075
	x.	Big Bend FGD System Reliability	201,270	214,239	223,188	229,421	236,123	241,059	244,407	273,135	276,227	278,859	279,823	279,600	2,977,349		2,977,349
	y.	Clean Air Mercury Rule	14,767	14,731	14,697	14,662	14,627	14,592	14,556	14,522	14,487	14,452	14,417	14,381	174,891		174,891
	z.	SO_2 Emissions Allowances (B)	(373)	(372)	(371)	(370)	(370)	(369)	(368)	(367)	(366)	(365)	(365)	(363)	(4,419)		(4,419)
2.		Total Investment Projects - Recoverable Costs	5,566,537	5,485,112	5,484,974	5,419,353	5,352,220	5,348,397	5,337,869	5,352,859	5,342,347	5,331,507	5,321,994	5,317,045	64,680,214	$ 222,700	$ 64,437,514
3.		Recoverable Costs Allocated to Energy	5,474,110	5,473,089	5,472,986	5,407,401	5,340,305	5,336,517	5,326,026	5,341,052	5,330,577	5,319,773	5,310,296	5,305,382	64,437,514		64,437,514
4.		Recoverable Costs Allocated to Demand	92,427	12,023	11,988	11,952	11,915	11,880	11,843	11,807	11,770	11,734	11,698	11,663	222,700	222,700	
5.		Retail Energy Jurisdictional Factor	0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272			
6.		Retail Demand Jurisdictional Factor	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152			
7.		Jurisdictional Energy Recoverable Costs (C)	5,463,337	5,462,297	5,461,422	5,398,002	5,330,746	5,328,579	5,314,818	5,327,194	5,321,401	5,313,532	5,309,809	5,304,996	64,336,133		
8.		Jurisdictional Demand Recoverable Costs (D)	92,040	11,973	11,938	11,902	11,865	11,830	11,793	11,758	11,721	11,685	11,649	11,614	221,768		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$5,555,377	$5,474,270	$5,473,360	$5,409,904	$5,342,611	$5,340,409	$5,326,611	$5,338,952	$5,333,122	$5,325,217	$5,321,458	$5,316,610	$64,557,901		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Project's Total Return Component on Form 42-8E, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other - (G)		47,957	34,499	74,851	104,389	78,220	37,817	149,247	268,020	475,442	294,608	252,518	255,894	$2,073,461
2.	Plant-in-Service/Depreciation Base (A)	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	
3.	Less: Accumulated Depreciation	(3,590,325)	(3,607,491)	(3,624,657)	(3,641,823)	(3,658,989)	(3,676,155)	(3,693,321)	(3,710,487)	(3,727,653)	(3,744,819)	(3,761,985)	(3,779,151)	(3,796,317)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,649,333	4,632,167	4,615,001	4,597,835	4,580,669	4,563,503	4,546,337	4,529,171	4,512,005	4,494,839	4,477,673	4,460,507	4,443,341	
6.	Average Net Investment		4,640,750	4,623,584	4,606,418	4,589,252	4,572,086	4,554,920	4,537,754	4,520,588	4,503,422	4,486,256	4,469,090	4,451,924	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		33,718	33,593	33,469	33,344	33,219	33,095	32,970	32,845	32,720	32,596	32,471	32,346	$396,386
	b. Debt Component Grossed Up For Taxes (C)		11,340	11,298	11,257	11,215	11,173	11,131	11,089	11,047	11,005	10,963	10,921	10,879	133,318
8.	Investment Expenses														
	a. Depreciation (D)		17,166	17,166	17,166	17,166	17,166	17,166	17,166	17,166	17,166	17,166	17,166	17,166	205,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		62,224	62,057	61,892	61,725	61,558	61,392	61,225	61,058	60,891	60,725	60,558	60,391	735,696
	a. Recoverable Costs Allocated to Energy		62,224	62,057	61,892	61,725	61,558	61,392	61,225	61,058	60,891	60,725	60,558	60,391	735,696
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		62,102	61,935	61,761	61,618	61,448	61,301	61,096	60,900	60,786	60,654	60,552	60,387	734,540
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$62,102	$61,935	$61,761	$61,618	$61,448	$61,301	$61,096	$60,900	$60,786	$60,654	$60,552	$60,387	$734,540

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Line 1d - Expenditures include AFUDC and are for tracking purposes only. Depreciation and Return are not calculated until the project goes in-service.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(3,017,126)	(3,033,267)	(3,049,408)	(3,065,549)	(3,081,690)	(3,097,831)	(3,113,972)	(3,130,113)	(3,146,254)	(3,162,395)	(3,178,536)	(3,194,677)	(3,210,818)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,000,608	1,984,467	1,968,326	1,952,185	1,936,044	1,919,903	1,903,762	1,887,621	1,871,480	1,855,339	1,839,198	1,823,057	1,806,916	
6.	Average Net Investment		1,992,538	1,976,397	1,960,256	1,944,115	1,927,974	1,911,833	1,895,692	1,879,551	1,863,410	1,847,269	1,831,128	1,814,987	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,477	14,360	14,243	14,125	14,008	13,891	13,773	13,656	13,539	13,422	13,304	13,187	$165,985
	b. Debt Component Grossed Up For Taxes (C)		4,869	4,830	4,790	4,751	4,711	4,672	4,632	4,593	4,554	4,514	4,475	4,435	55,826
8.	Investment Expenses														
	a. Depreciation (D)		16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	193,692
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		35,487	35,331	35,174	35,017	34,860	34,704	34,546	34,390	34,234	34,077	33,920	33,763	415,503
	a. Recoverable Costs Allocated to Energy		35,487	35,331	35,174	35,017	34,860	34,704	34,546	34,390	34,234	34,077	33,920	33,763	415,503
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		35,417	35,261	35,100	34,956	34,798	34,652	34,473	34,301	34,175	34,037	33,917	33,761	414,848
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$35,417	$35,261	$35,100	$34,956	$34,798	$34,652	$34,473	$34,301	$34,175	$34,037	$33,917	$33,761	$414,848

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(375,845)	(378,155)	(380,465)	(382,775)	(385,085)	(387,395)	(389,705)	(392,015)	(394,325)	(396,635)	(398,945)	(401,255)	(403,565)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$490,366	488,056	485,746	483,436	481,126	478,816	476,506	474,196	471,886	469,576	467,266	464,956	462,646	
6.	Average Net Investment		489,211	486,901	484,591	482,281	479,971	477,661	475,351	473,041	470,731	468,421	466,111	463,801	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,554	3,538	3,521	3,504	3,487	3,471	3,454	3,437	3,420	3,403	3,387	3,370	$41,546
	b. Debt Component Grossed Up For Taxes (C)		1,195	1,190	1,184	1,179	1,173	1,167	1,162	1,156	1,150	1,145	1,139	1,133	13,973
8.	Investment Expenses														
	a. Depreciation (D)		2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,059	7,038	7,015	6,993	6,970	6,948	6,926	6,903	6,880	6,858	6,836	6,813	83,239
	a. Recoverable Costs Allocated to Energy		7,059	7,038	7,015	6,993	6,970	6,948	6,926	6,903	6,880	6,858	6,836	6,813	83,239
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		7,045	7,024	7,000	6,981	6,958	6,938	6,911	6,885	6,868	6,850	6,835	6,813	83,108
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,045	$7,024	$7,000	$6,981	$6,958	$6,938	$6,911	$6,885	$6,868	$6,850	$6,835	$6,813	$83,108

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(172,432)	(173,842)	(175,252)	(176,662)	(178,072)	(179,482)	(180,892)	(182,302)	(183,712)	(185,122)	(186,532)	(187,942)	(189,352)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$325,146	323,736	322,326	320,916	319,506	318,096	316,686	315,276	313,866	312,456	311,046	309,636	308,226	
6.	Average Net Investment		324,441	323,031	321,621	320,211	318,801	317,391	315,981	314,571	313,161	311,751	310,341	308,931	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,357	2,347	2,337	2,327	2,316	2,306	2,296	2,286	2,275	2,265	2,255	2,245	$27,612
	b. Debt Component Grossed Up For Taxes (C)		793	789	786	782	779	776	772	769	765	762	758	755	9,286
8.	Investment Expenses														
	a. Depreciation (D)		1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	16,920
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,560	4,546	4,533	4,519	4,505	4,492	4,478	4,465	4,450	4,437	4,423	4,410	53,818
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,560	4,546	4,533	4,519	4,505	4,492	4,478	4,465	4,450	4,437	4,423	4,410	53,818
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,541	4,527	4,514	4,500	4,486	4,473	4,459	4,446	4,431	4,418	4,404	4,392	53,591
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,541	$4,527	$4,514	$4,500	$4,486	$4,473	$4,459	$4,446	$4,431	$4,418	$4,404	$4,392	$53,591

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(283,624)	(285,943)	(288,262)	(290,581)	(292,900)	(295,219)	(297,538)	(299,857)	(302,176)	(304,495)	(306,814)	(309,133)	(311,452)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$534,777	532,458	530,139	527,820	525,501	523,182	520,863	518,544	516,225	513,906	511,587	509,268	506,949	
6.	Average Net Investment		533,618	531,299	528,980	526,661	524,342	522,023	519,704	517,385	515,066	512,747	510,428	508,109	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,877	3,860	3,843	3,827	3,810	3,793	3,776	3,759	3,742	3,725	3,709	3,692	$45,413
	b. Debt Component Grossed Up For Taxes (C)		1,304	1,298	1,293	1,287	1,281	1,276	1,270	1,264	1,259	1,253	1,247	1,242	15,274
8.	Investment Expenses														
	a. Depreciation (D)		2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	27,828
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,500	7,477	7,455	7,433	7,410	7,388	7,365	7,342	7,320	7,297	7,275	7,253	88,515
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,500	7,477	7,455	7,433	7,410	7,388	7,365	7,342	7,320	7,297	7,275	7,253	88,515
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		7,469	7,446	7,424	7,402	7,379	7,357	7,334	7,311	7,289	7,266	7,245	7,223	88,145
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,469	$7,446	$7,424	$7,402	$7,379	$7,357	$7,334	$7,311	$7,289	$7,266	$7,245	$7,223	$88,145

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		57,277	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	
2.	Plant-in-Service/Depreciation Base (A)	$57,277	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	(25,968)	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$31,309	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		15,655	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		114	0	0	0	0	0	0	0	0	0	0	0	$114
	b. Debt Component Grossed Up For Taxes (C)		38	0	0	0	0	0	0	0	0	0	0	0	38
8.	Investment Expenses														
	a. Depreciation (D)		31,166	0	0	0	0	0	0	0	0	0	0	0	31,166
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		31,318	0	0	0	0	0	0	0	0	0	0	0	31,318
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		31,318	0	0	0	0	0	0	0	0	0	0	0	31,318
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		31,187	0	0	0	0	0	0	0	0	0	0	0	31,187
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$31,187	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$31,187

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 0.0% in accordance with FPSC Order No. PSC-12-0175-PAA-EI.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		90,472	0	0	0	0	0	0	0	0	0	0	0	$90,472
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	$0
2.	Plant-in-Service/Depreciation Base (A)	$90,472	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	(41,435)	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$49,037	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		24,519	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		178	0	0	0	0	0	0	0	0	0	0	0	$178
	b. Debt Component Grossed Up For Taxes (C)		60	0	0	0	0	0	0	0	0	0	0	0	60
8.	Investment Expenses														
	a. Depreciation (D)		48,811	0	0	0	0	0	0	0	0	0	0	0	48,811
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		49,049	0	0	0	0	0	0	0	0	0	0	0	49,049
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		49,049	0	0	0	0	0	0	0	0	0	0	0	49,049
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		48,844	0	0	0	0	0	0	0	0	0	0	0	48,844
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$48,844	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$48,844

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 0.0% in accordance with FPSC Order No. PSC-12-0175-PAA-EI.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 7 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(605,912)	(610,300)	(614,688)	(619,076)	(623,464)	(627,852)	(632,240)	(636,628)	(641,016)	(645,404)	(649,792)	(654,180)	(658,568)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$710,345	705,957	701,569	697,181	692,793	688,405	684,017	679,629	675,241	670,853	666,465	662,077	657,689	
6.	Average Net Investment		708,151	703,763	699,375	694,987	690,599	686,211	681,823	677,435	673,047	668,659	664,271	659,883	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,145	5,113	5,081	5,050	5,018	4,986	4,954	4,922	4,890	4,858	4,826	4,794	$59,637
	b. Debt Component Grossed Up For Taxes (C)		1,730	1,720	1,709	1,698	1,688	1,677	1,666	1,655	1,645	1,634	1,623	1,613	20,058
8.	Investment Expenses														
	a. Depreciation (D)		4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		11,263	11,221	11,178	11,136	11,094	11,051	11,008	10,965	10,923	10,880	10,837	10,795	132,351
	a. Recoverable Costs Allocated to Energy		11,263	11,221	11,178	11,136	11,094	11,051	11,008	10,965	10,923	10,880	10,837	10,795	132,351
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		11,241	11,199	11,154	11,117	11,074	11,035	10,985	10,937	10,904	10,867	10,836	10,794	132,143
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,241	$11,199	$11,154	$11,117	$11,074	$11,035	$10,985	$10,937	$10,904	$10,867	$10,836	$10,794	$132,143

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(460,278)	(463,314)	(466,350)	(469,386)	(472,422)	(475,458)	(478,494)	(481,530)	(484,566)	(487,602)	(490,638)	(493,674)	(496,710)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$524,516	521,480	518,444	515,408	512,372	509,336	506,300	503,264	500,228	497,192	494,156	491,120	488,084	
6.	Average Net Investment		522,998	519,962	516,926	513,890	510,854	507,818	504,782	501,746	498,710	495,674	492,638	489,602	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,800	3,778	3,756	3,734	3,712	3,690	3,668	3,646	3,623	3,601	3,579	3,557	$44,144
	b. Debt Component Grossed Up For Taxes (C)		1,278	1,271	1,263	1,256	1,248	1,241	1,234	1,226	1,219	1,211	1,204	1,196	14,847
8.	Investment Expenses														
	a. Depreciation (D)		3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	36,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,114	8,085	8,055	8,026	7,996	7,967	7,938	7,908	7,878	7,848	7,819	7,789	95,423
	a. Recoverable Costs Allocated to Energy		8,114	8,085	8,055	8,026	7,996	7,967	7,938	7,908	7,878	7,848	7,819	7,789	95,423
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		8,098	8,069	8,038	8,012	7,982	7,955	7,921	7,887	7,864	7,839	7,818	7,788	95,271
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,098	$8,069	$8,038	$8,012	$7,982	$7,955	$7,921	$7,887	$7,864	$7,839	$7,818	$7,788	$95,271

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(30,883)	(31,175)	(31,467)	(31,759)	(32,051)	(32,343)	(32,635)	(32,927)	(33,219)	(33,511)	(33,803)	(34,095)	(34,387)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$89,854	89,562	89,270	88,978	88,686	88,394	88,102	87,810	87,518	87,226	86,934	86,642	86,350	
6.	Average Net Investment		89,708	89,416	89,124	88,832	88,540	88,248	87,956	87,664	87,372	87,080	86,788	86,496	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		652	650	648	645	643	641	639	637	635	633	631	628	$7,682
	b. Debt Component Grossed Up For Taxes (C)		219	219	218	217	216	216	215	214	214	213	212	211	2,584
8.	Investment Expenses														
	a. Depreciation (D)		292	292	292	292	292	292	292	292	292	292	292	292	3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,163	1,161	1,158	1,154	1,151	1,149	1,146	1,143	1,141	1,138	1,135	1,131	13,770
	a. Recoverable Costs Allocated to Energy		1,163	1,161	1,158	1,154	1,151	1,149	1,146	1,143	1,141	1,138	1,135	1,131	13,770
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		1,161	1,159	1,156	1,152	1,149	1,147	1,144	1,140	1,139	1,137	1,135	1,131	13,750
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,161	$1,159	$1,156	$1,152	$1,149	$1,147	$1,144	$1,140	$1,139	$1,137	$1,135	$1,131	$13,750

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		($26,750)	$298	$106,835	$43,064	$18,764	($11,932)	$2,664	$5,983	$4,092	$0	$0	$1,798	$144,817
	b. Clearings to Plant		(26,750)	298	214,237	43,064	652,334	(11,932)	2,664	5,983	4,092	0	0	89,410	973,400
	c. Retirements		0	0	0	0	0	0	0	0	0	0		0	
	d. Other - (G)		$84,105	$129,676	$22,752	$30,377	$9,108	$1,462	$118,184	$22,052	$27,150	$318,151	$89,990	$41,090	894,097
2.	Plant-in-Service/Depreciation Base (A)	$88,383,835	$88,357,086	$88,357,384	$88,571,622	$88,614,685	$89,267,018	$89,255,086	$89,257,750	$89,263,733	$89,267,825	$89,267,825	$89,267,825	$89,357,235	
3.	Less: Accumulated Depreciation	(36,789,770)	(37,032,826)	(37,275,808)	(37,518,791)	(37,762,363)	(38,006,053)	(38,251,537)	(38,496,988)	(38,742,447)	(38,987,922)	(39,233,409)	(39,478,896)	(39,724,383)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5.	Net Investment (Lines 2 + 3 + 4)	$51,594,065	51,324,260	51,081,576	51,052,831	50,852,323	51,260,965	51,003,549	50,760,762	50,521,286	50,279,903	50,034,416	49,788,929	49,632,852	
6.	Average Net Investment		51,459,163	51,202,918	51,067,203	50,952,577	51,056,644	51,132,257	50,882,156	50,641,024	50,400,595	50,157,160	49,911,673	49,710,891	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		373,885	372,023	371,037	370,204	370,961	371,510	369,693	367,941	366,194	364,425	362,642	361,183	$4,421,698
	b. Debt Component Grossed Up For Taxes (C)		125,749	125,123	124,791	124,511	124,765	124,950	124,339	123,750	123,162	122,567	121,967	121,477	1,487,151
8.	Investment Expenses														
	a. Depreciation (D)		243,056	242,982	242,983	243,572	243,690	245,484	245,451	245,459	245,475	245,487	245,487	245,487	2,934,613
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		742,690	740,128	738,811	738,287	739,416	741,944	739,483	737,150	734,831	732,479	730,096	728,147	8,843,462
	a. Recoverable Costs Allocated to Energy		742,690	740,128	738,811	738,287	739,416	741,944	739,483	737,150	734,831	732,479	730,096	728,147	8,843,462
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		741,228	738,669	737,250	737,004	738,093	740,840	737,927	735,237	733,566	731,620	730,029	728,094	8,829,557
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$741,228	$738,669	$737,250	$737,004	$738,093	$740,840	$737,927	$735,237	$733,566	$731,620	$730,029	$728,094	$8,829,557

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Line 1d - Expenditures include AFUDC and are for tracking purposes only. Depreciation and Return are not calculated until the project goes in-service.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(5,531,197)	(5,576,471)	(5,621,745)	(5,667,019)	(5,712,293)	(5,757,567)	(5,802,841)	(5,848,115)	(5,893,389)	(5,938,663)	(5,983,937)	(6,029,211)	(6,074,485)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$16,208,540	16,163,266	16,117,992	16,072,718	16,027,444	15,982,170	15,936,896	15,891,622	15,846,348	15,801,074	15,755,800	15,710,526	15,665,252	
6.	Average Net Investment		16,185,903	16,140,629	16,095,355	16,050,081	16,004,807	15,959,533	15,914,259	15,868,985	15,823,711	15,778,437	15,733,163	15,687,889	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		117,601	117,272	116,943	116,615	116,286	115,957	115,628	115,299	114,970	114,641	114,312	113,983	$1,389,507
	b. Debt Component Grossed Up For Taxes (C)		39,553	39,442	39,332	39,221	39,110	39,000	38,889	38,779	38,668	38,557	38,447	38,336	467,334
8.	Investment Expenses														
	a. Depreciation (D)		45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	543,288
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		202,428	201,988	201,549	201,110	200,670	200,231	199,791	199,352	198,912	198,472	198,033	197,593	2,400,129
	a. Recoverable Costs Allocated to Energy		202,428	201,988	201,549	201,110	200,670	200,231	199,791	199,352	198,912	198,472	198,033	197,593	2,400,129
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		202,030	201,590	201,123	200,760	200,311	199,933	199,371	198,835	198,570	198,239	198,015	197,579	2,396,356
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$202,030	$201,590	$201,123	$200,760	$200,311	$199,933	$199,371	$198,835	$198,570	$198,239	$198,015	$197,579	$2,396,356

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 2.0% and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Actual November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	2,605,227	2,595,043	2,584,859	2,574,675	2,564,491	2,554,307	2,544,123	2,533,939	2,523,755	2,513,571	2,503,387	2,493,203	2,483,019	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,796,079	5,785,895	5,775,711	5,765,527	5,755,343	5,745,159	5,734,975	5,724,791	5,714,607	5,704,423	5,694,239	5,684,055	5,673,871	
6.	Average Net Investment		5,790,987	5,780,803	5,770,619	5,760,435	5,750,251	5,740,067	5,729,883	5,719,699	5,709,515	5,699,331	5,689,147	5,678,963	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		42,075	42,001	41,927	41,853	41,779	41,705	41,631	41,557	41,483	41,409	41,335	41,261	$500,016
	b. Debt Component Grossed Up For Taxes (C)		14,151	14,126	14,101	14,077	14,052	14,027	14,002	13,977	13,952	13,927	13,902	13,877	168,171
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,410	66,311	66,212	66,114	66,015	65,916	65,817	65,718	65,619	65,520	65,421	65,322	790,395
	a. Recoverable Costs Allocated to Energy		66,410	66,311	66,212	66,114	66,015	65,916	65,817	65,718	65,619	65,520	65,421	65,322	790,395
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		66,279	66,180	66,072	65,999	65,897	65,818	65,679	65,547	65,506	65,443	65,415	65,317	789,152
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,279	$66,180	$66,072	$65,999	$65,897	$65,818	$65,679	$65,547	$65,506	$65,443	$65,415	$65,317	$789,152

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 4.0%, 3.7%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$1,841	$0	$0	$0	$0	$0	$11,000	$10,000	$29,751	$362,000	$1,158,149	$1,572,741
	b. Clearings to Plant		0	1,841	0	0	0	0	0	0	0	0	0	0	$1,841
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$8,517,765	$8,517,765	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$8,519,606	
3.	Less: Accumulated Depreciation	(1,722,767)	(1,749,056)	(1,775,345)	(1,801,640)	(1,827,935)	(1,854,230)	(1,880,525)	(1,906,820)	(1,933,115)	(1,959,410)	(1,985,705)	(2,012,000)	(2,038,295)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	11,000	21,000	50,751	412,751	1,570,900	
5.	Net Investment (Lines 2 + 3 + 4)	$6,794,998	6,768,709	6,744,261	6,717,966	6,691,671	6,665,376	6,639,081	6,612,786	6,597,491	6,581,196	6,584,652	6,920,357	8,052,211	
6.	Average Net Investment		6,781,854	6,756,485	6,731,114	6,704,819	6,678,524	6,652,229	6,625,934	6,605,139	6,589,344	6,582,924	6,752,505	7,486,284	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		49,275	49,090	48,906	48,715	48,524	48,333	48,142	47,991	47,876	47,829	49,061	54,393	$588,135
	b. Debt Component Grossed Up For Taxes (C)		16,573	16,511	16,449	16,384	16,320	16,256	16,192	16,141	16,102	16,086	16,501	18,294	197,809
8.	Investment Expenses														
	a. Depreciation (D)		26,289	26,289	26,295	26,295	26,295	26,295	26,295	26,295	26,295	26,295	26,295	26,295	315,528
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		92,137	91,890	91,650	91,394	91,139	90,884	90,629	90,427	90,273	90,210	91,857	98,982	1,101,472
	a. Recoverable Costs Allocated to Energy		92,137	91,890	91,650	91,394	91,139	90,884	90,629	90,427	90,273	90,210	91,857	98,982	1,101,472
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		91,956	91,709	91,456	91,235	90,976	90,749	90,438	90,192	90,118	90,104	91,849	98,975	1,099,757
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$91,956	$91,709	$91,456	$91,235	$90,976	$90,749	$90,438	$90,192	$90,118	$90,104	$91,849	$98,975	$1,099,757

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 4.0%, 3.7%, 3.5%, 3.5%, 3.2%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(417,882)	(422,306)	(426,730)	(431,154)	(435,578)	(440,002)	(444,426)	(448,850)	(453,274)	(457,698)	(462,122)	(466,546)	(470,970)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,143,591	1,139,167	1,134,743	1,130,319	1,125,895	1,121,471	1,117,047	1,112,623	1,108,199	1,103,775	1,099,351	1,094,927	1,090,503	
6.	Average Net Investment		1,141,379	1,136,955	1,132,531	1,128,107	1,123,683	1,119,259	1,114,835	1,110,411	1,105,987	1,101,563	1,097,139	1,092,715	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,293	8,261	8,229	8,196	8,164	8,132	8,100	8,068	8,036	8,004	7,971	7,939	$97,393
	b. Debt Component Grossed Up For Taxes (C)		2,789	2,778	2,768	2,757	2,746	2,735	2,724	2,713	2,703	2,692	2,681	2,670	32,756
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,506	15,463	15,421	15,377	15,334	15,291	15,248	15,205	15,163	15,120	15,076	15,033	183,237
	a. Recoverable Costs Allocated to Energy		15,506	15,463	15,421	15,377	15,334	15,291	15,248	15,205	15,163	15,120	15,076	15,033	183,237
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		15,475	15,433	15,388	15,350	15,307	15,268	15,216	15,166	15,137	15,102	15,075	15,032	182,949
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,475	$15,433	$15,388	$15,350	$15,307	$15,268	$15,216	$15,166	$15,137	$15,102	$15,075	$15,032	$182,949

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(448,850)	(455,247)	(461,644)	(468,041)	(474,438)	(480,835)	(487,232)	(493,629)	(500,026)	(506,423)	(512,820)	(519,217)	(525,614)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,109,880	2,103,483	2,097,086	2,090,689	2,084,292	2,077,895	2,071,498	2,065,101	2,058,704	2,052,307	2,045,910	2,039,513	2,033,116	
6.	Average Net Investment		2,106,682	2,100,285	2,093,888	2,087,491	2,081,094	2,074,697	2,068,300	2,061,903	2,055,506	2,049,109	2,042,712	2,036,315	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,306	15,260	15,213	15,167	15,121	15,074	15,028	14,981	14,935	14,888	14,842	14,795	$180,610
	b. Debt Component Grossed Up For Taxes (C)		5,148	5,132	5,117	5,101	5,086	5,070	5,054	5,039	5,023	5,007	4,992	4,976	60,745
8.	Investment Expenses														
	a. Depreciation (D)		6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		26,851	26,789	26,727	26,665	26,604	26,541	26,479	26,417	26,355	26,292	26,231	26,168	318,119
	a. Recoverable Costs Allocated to Energy		26,851	26,789	26,727	26,665	26,604	26,541	26,479	26,417	26,355	26,292	26,231	26,168	318,119
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		26,798	26,736	26,671	26,619	26,556	26,502	26,423	26,348	26,310	26,261	26,229	26,166	317,619
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$26,798	$26,736	$26,671	$26,619	$26,556	$26,502	$26,423	$26,348	$26,310	$26,261	$26,229	$26,166	$317,619

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(269,845)	(275,342)	(280,839)	(286,336)	(291,833)	(297,330)	(302,827)	(308,324)	(313,821)	(319,318)	(324,815)	(330,312)	(335,809)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,379,276	1,373,779	1,368,282	1,362,785	1,357,288	1,351,791	1,346,294	1,340,797	1,335,300	1,329,803	1,324,306	1,318,809	1,313,312	
6.	Average Net Investment		1,376,528	1,371,031	1,365,534	1,360,037	1,354,540	1,349,043	1,343,546	1,338,049	1,332,552	1,327,055	1,321,558	1,316,061	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,001	9,961	9,922	9,882	9,842	9,802	9,762	9,722	9,682	9,642	9,602	9,562	$117,382
	b. Debt Component Grossed Up For Taxes (C)		3,364	3,350	3,337	3,323	3,310	3,297	3,283	3,270	3,256	3,243	3,229	3,216	39,478
8.	Investment Expenses														
	a. Depreciation (D)		5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,862	18,808	18,756	18,702	18,649	18,596	18,542	18,489	18,435	18,382	18,328	18,275	222,824
	a. Recoverable Costs Allocated to Energy		18,862	18,808	18,756	18,702	18,649	18,596	18,542	18,489	18,435	18,382	18,328	18,275	222,824
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		18,825	18,771	18,716	18,669	18,616	18,568	18,503	18,441	18,403	18,360	18,326	18,274	222,472
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,825	$18,771	$18,716	$18,669	$18,616	$18,568	$18,503	$18,441	$18,403	$18,360	$18,326	$18,274	$222,472

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(243,176)	(248,053)	(252,930)	(257,807)	(262,684)	(267,561)	(272,438)	(277,315)	(282,192)	(287,069)	(291,946)	(296,823)	(301,700)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,338,711	1,333,834	1,328,957	1,324,080	1,319,203	1,314,326	1,309,449	1,304,572	1,299,695	1,294,818	1,289,941	1,285,064	1,280,187	
6.	Average Net Investment		1,336,273	1,331,396	1,326,519	1,321,642	1,316,765	1,311,888	1,307,011	1,302,134	1,297,257	1,292,380	1,287,503	1,282,626	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,709	9,673	9,638	9,603	9,567	9,532	9,496	9,461	9,425	9,390	9,355	9,319	$114,168
	b. Debt Component Grossed Up For Taxes (C)		3,265	3,253	3,242	3,230	3,218	3,206	3,194	3,182	3,170	3,158	3,146	3,134	38,398
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,851	17,803	17,757	17,710	17,662	17,615	17,567	17,520	17,472	17,425	17,378	17,330	211,090
	a. Recoverable Costs Allocated to Energy		17,851	17,803	17,757	17,710	17,662	17,615	17,567	17,520	17,472	17,425	17,378	17,330	211,090
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		17,816	17,768	17,719	17,679	17,630	17,589	17,530	17,475	17,442	17,405	17,376	17,329	210,758
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,816	$17,768	$17,719	$17,679	$17,630	$17,589	$17,530	$17,475	$17,442	$17,405	$17,376	$17,329	$210,758

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(259,586)	(267,539)	(275,492)	(283,445)	(291,398)	(299,351)	(307,304)	(315,257)	(323,210)	(331,163)	(339,116)	(347,069)	(355,022)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,446,921	2,438,968	2,431,015	2,423,062	2,415,109	2,407,156	2,399,203	2,391,250	2,383,297	2,375,344	2,367,391	2,359,438	2,351,485	
6.	Average Net Investment		2,442,945	2,434,992	2,427,039	2,419,086	2,411,133	2,403,180	2,395,227	2,387,274	2,379,321	2,371,368	2,363,415	2,355,462	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		17,750	17,692	17,634	17,576	17,518	17,461	17,403	17,345	17,287	17,230	17,172	17,114	$209,182
	b. Debt Component Grossed Up For Taxes (C)		5,970	5,950	5,931	5,911	5,892	5,873	5,853	5,834	5,814	5,795	5,775	5,756	70,354
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		31,673	31,595	31,518	31,440	31,363	31,287	31,209	31,132	31,054	30,978	30,900	30,823	374,972
	a. Recoverable Costs Allocated to Energy		31,673	31,595	31,518	31,440	31,363	31,287	31,209	31,132	31,054	30,978	30,900	30,823	374,972
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		31,611	31,533	31,451	31,385	31,307	31,240	31,143	31,051	31,001	30,942	30,897	30,821	374,382
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$31,611	$31,533	$31,451	$31,385	$31,307	$31,240	$31,143	$31,051	$31,001	$30,942	$30,897	$30,821	$374,382

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	**$84,099,314**	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	
3.	Less: Accumulated Depreciation	**(3,686,991)**	(3,990,353)	(4,293,715)	(4,597,077)	(7,965,677)	(8,269,039)	(8,572,401)	(8,875,763)	(9,179,125)	(9,482,487)	(9,785,849)	(10,089,211)	(10,392,573)	
4.	CWIP - Non-Interest Bearing	**0**	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$80,412,323	80,108,961	79,805,599	79,502,237	76,133,637	75,830,275	75,526,913	75,223,551	74,920,189	74,616,827	74,313,465	74,010,103	73,706,741	
6.	Average Net Investment		80,260,642	79,957,280	79,653,918	77,817,937	75,981,956	75,678,594	75,375,232	75,071,870	74,768,508	74,465,146	74,161,784	73,858,422	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		583,147	580,943	578,739	565,399	552,060	549,855	547,651	545,447	543,243	541,039	538,835	536,631	$6,662,989
	b. Debt Component Grossed Up For Taxes (C)		196,130	195,389	194,648	190,161	185,675	184,933	184,192	183,451	182,709	181,968	181,227	180,485	2,240,968
8.	Investment Expenses														
	a. Depreciation (D)		303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	3,640,344
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,082,639	1,079,694	1,076,749	1,058,922	1,041,097	1,038,150	1,035,205	1,032,260	1,029,314	1,026,369	1,023,424	1,020,478	12,544,301
	a. Recoverable Costs Allocated to Energy		1,082,639	1,079,694	1,076,749	1,058,922	1,041,097	1,038,150	1,035,205	1,032,260	1,029,314	1,026,369	1,023,424	1,020,478	12,544,301
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		1,080,508	1,077,565	1,074,474	1,057,081	1,039,234	1,036,606	1,033,027	1,029,582	1,027,542	1,025,165	1,023,330	1,020,404	12,524,518
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,080,508	$1,077,565	$1,074,474	$1,057,081	$1,039,234	$1,036,606	$1,033,027	$1,029,582	$1,027,542	$1,025,165	$1,023,330	$1,020,404	$12,524,518

Notes:
(A) Applicable depreciable base for Big Bend; account 311.51 ($22,278,982), 312.51 ($46,909,884), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8% and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$436	$0	$772,962	$98,362	$25,341	$27,734	$0	$0	$0	$0	$285,969	$0	$1,210,804
	b. Clearings to Plant		436	0	0	0	0	0	0	0	0	0	0	1,722,583	$1,723,019
	c. Retirements		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	
2.	*Plant-in-Service/Depreciation Base (A)*	*$92,325,259*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$92,325,695*	*$94,048,278*	
3.	Less: Accumulated Depreciation	(5,415,519)	(5,713,853)	(6,012,188)	(6,310,523)	(10,111,715)	(10,410,050)	(10,708,385)	(11,006,720)	(11,305,055)	(11,603,390)	(11,901,725)	(12,200,060)	(12,498,395)	
4.	CWIP - Non-Interest Bearing	512,215	512,215	512,215	1,285,177	1,383,539	1,408,880	1,436,614	1,436,614	1,436,614	1,436,614	1,436,614	1,722,583	(0)	
5.	Net Investment (Lines 2 + 3 + 4)	$87,421,955	87,124,057	86,825,722	87,300,349	83,597,519	83,324,525	83,053,924	82,755,589	82,457,254	82,158,919	81,860,584	81,848,218	81,549,883	
6.	Average Net Investment		87,273,006	86,974,890	87,063,035	85,448,934	83,461,022	83,189,224	82,904,756	82,606,421	82,308,086	82,009,751	81,854,401	81,699,050	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		634,097	631,931	632,571	620,843	606,400	604,425	602,358	600,191	598,023	595,856	594,727	593,598	$7,315,020
	b. Debt Component Grossed Up For Taxes (C)		213,266	212,538	212,753	208,809	203,951	203,287	202,592	201,863	201,134	200,404	200,025	199,645	2,460,267
8.	Investment Expenses														
	a. Depreciation (D)		298,334	298,335	298,335	298,335	298,335	298,335	298,335	298,335	298,335	298,335	298,335	298,335	3,580,019
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,145,697	1,142,804	1,143,659	1,127,987	1,108,686	1,106,047	1,103,285	1,100,389	1,097,492	1,094,595	1,093,087	1,091,578	13,355,306
	a. Recoverable Costs Allocated to Energy		1,145,697	1,142,804	1,143,659	1,127,987	1,108,686	1,106,047	1,103,285	1,100,389	1,097,492	1,094,595	1,093,087	1,091,578	13,355,306
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		1,143,442	1,140,551	1,141,242	1,126,026	1,106,702	1,104,402	1,100,963	1,097,534	1,095,603	1,093,311	1,092,987	1,091,499	13,334,262
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,143,442	$1,140,551	$1,141,242	$1,126,026	$1,106,702	$1,104,402	$1,100,963	$1,097,534	$1,095,603	$1,093,311	$1,092,987	$1,091,499	$13,334,262

Notes:
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52($51,966,366), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$13,642	$1,371	$857	$4,769	($22)	$949	$1,190	$18,250	$16,650	$33,100	$1,638	$1,162	$93,556
	b. Clearings to Plant		1,888	0	0	0	0	0	0	0	0	0	0	268,892	270,780
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$80,163,199	$80,165,087	$80,165,087	$80,165,087	$80,165,087	$80,165,087	$80,165,087	$80,165,087	$80,165,087	$80,165,087	$80,165,087	$80,165,087	$80,433,979	
3.	Less: Accumulated Depreciation	(6,400,221)	(6,647,090)	(6,893,965)	(7,140,840)	(11,070,725)	(11,317,600)	(11,564,475)	(11,811,350)	(12,058,225)	(12,305,100)	(12,551,975)	(12,798,850)	(13,045,725)	
4.	CWIP - Non-Interest Bearing	177,224	188,978	190,348	191,206	195,975	195,953	196,902	198,092	216,342	232,992	266,092	267,730	0	
5.	Net Investment (Lines 2 + 3 + 4)	$73,940,202	73,706,975	73,461,470	73,215,453	69,290,337	69,043,440	68,797,514	68,551,829	68,323,204	68,092,979	67,879,204	67,633,967	67,388,254	
6.	Average Net Investment		73,823,588	73,584,223	73,338,461	71,252,895	69,166,889	68,920,477	68,674,671	68,437,516	68,208,091	67,986,091	67,756,585	67,511,110	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		536,378	534,638	532,853	517,700	502,544	500,753	498,967	497,244	495,577	493,964	492,297	490,513	$6,093,428
	b. Debt Component Grossed Up For Taxes (C)		180,400	179,815	179,215	174,118	169,021	168,419	167,818	167,238	166,678	166,135	165,575	164,975	2,049,407
8.	Investment Expenses														
	a. Depreciation (D)		246,869	246,875	246,875	246,875	246,875	246,875	246,875	246,875	246,875	246,875	246,875	246,875	2,962,494
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		963,647	961,328	958,943	938,693	918,440	916,047	913,660	911,357	909,130	906,974	904,747	902,363	11,105,329
	a. Recoverable Costs Allocated to Energy		963,647	961,328	958,943	938,693	918,440	916,047	913,660	911,357	909,130	906,974	904,747	902,363	11,105,329
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		961,751	959,432	956,917	937,061	916,796	914,684	911,737	908,992	907,565	905,910	904,664	902,297	11,087,806
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$961,751	$959,432	$956,917	$937,061	$916,796	$914,684	$911,737	$908,992	$907,565	$905,910	$904,664	$902,297	$11,087,806

Notes:
(A) Applicable depreciable base for Big Bend; account 311.53 ($21,689,422), 312.53 ($44,228,920), 315.53 ($13,690,954), and 316.53 ($824,683).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.1%, 3.9%, 4.0%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	
3.	Less: Accumulated Depreciation	(6,448,484)	(6,628,452)	(6,808,420)	(6,988,388)	(10,107,159)	(10,287,127)	(10,467,095)	(10,647,063)	(10,827,031)	(11,006,999)	(11,186,967)	(11,366,935)	(11,546,903)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$56,404,549	56,224,581	56,044,613	55,864,645	52,745,874	52,565,906	52,385,938	52,205,970	52,026,002	51,846,034	51,666,066	51,486,098	51,306,130	
6.	Average Net Investment		56,314,565	56,134,597	55,954,629	54,305,260	52,655,890	52,475,922	52,295,954	52,115,986	51,936,018	51,756,050	51,576,082	51,396,114	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		409,163	407,855	406,548	394,564	382,580	381,273	379,965	378,657	377,350	376,042	374,735	373,427	$4,642,159
	b. Debt Component Grossed Up For Taxes (C)		137,614	137,174	136,734	132,704	128,673	128,234	127,794	127,354	126,914	126,475	126,035	125,595	1,561,300
8.	Investment Expenses														
	a. Depreciation (D)		179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	2,159,616
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		726,745	724,997	723,250	707,236	691,221	689,475	687,727	685,979	684,232	682,485	680,738	678,990	8,363,075
	a. Recoverable Costs Allocated to Energy		726,745	724,997	723,250	707,236	691,221	689,475	687,727	685,979	684,232	682,485	680,738	678,990	8,363,075
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		725,315	723,567	721,722	706,007	689,984	688,449	686,280	684,199	683,054	681,684	680,676	678,941	8,349,878
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$725,315	$723,567	$721,722	$706,007	$689,984	$688,449	$686,280	$684,199	$683,054	$681,684	$680,676	$678,941	$8,349,878

Notes:
(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($34,665,822), 315.54 ($10,642,027), and 316.54 ($687,934).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4%, 3.8%. 3.9%, and 3.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$1,402,139	$1,318,903	$573,415	$760,272	$669,701	$396,532	$342,417	$290,831	$323,400	$183,188	$41,182	$0	$6,301,979
	b. Clearings to Plant		0	0	0	0	0	0	$12,489,768	$290,831	$323,400	$183,188	$41,182	0	13,328,369
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$24,055,794	$24,346,625	$24,670,025	$24,853,213	$24,894,395	$24,894,395	
3.	Less: Accumulated Depreciation	(1,095,901)	(1,120,604)	(1,145,307)	(1,170,010)	(1,194,713)	(1,219,416)	(1,244,119)	(1,268,822)	(1,319,545)	(1,370,874)	(1,422,877)	(1,475,262)	(1,527,733)	
4.	CWIP - Non-Interest Bearing	7,026,389	8,428,528	9,747,431	10,320,846	11,081,118	11,750,819	12,147,351	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,496,517	18,873,953	20,168,153	20,716,865	21,452,434	22,097,431	22,469,260	22,786,972	23,027,080	23,299,151	23,430,336	23,419,133	23,366,662	
6.	Average Net Investment		18,185,235	19,521,053	20,442,509	21,084,649	21,774,933	22,283,346	22,628,116	22,907,026	23,163,115	23,364,743	23,424,734	23,392,897	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		132,128	141,833	148,528	153,194	158,209	161,903	164,408	166,435	168,295	169,760	170,196	169,965	$1,904,854
	b. Debt Component Grossed Up For Taxes (C)		44,439	47,703	49,955	51,524	53,211	54,453	55,296	55,977	56,603	57,096	57,242	57,164	640,663
8.	Investment Expenses														
	a. Depreciation (D)		24,703	24,703	24,703	24,703	24,703	24,703	24,703	50,723	51,329	52,003	52,385	52,471	431,832
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		201,270	214,239	223,186	229,421	236,123	241,059	244,407	273,135	276,227	278,859	279,823	279,600	2,977,349
	a. Recoverable Costs Allocated to Energy		201,270	214,239	223,186	229,421	236,123	241,059	244,407	273,135	276,227	278,859	279,823	279,600	2,977,349
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		200,874	213,817	222,714	229,022	235,700	240,700	243,893	272,426	275,752	278,532	279,797	279,580	2,972,807
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$200,874	$213,817	$222,714	$229,022	$235,700	$240,700	$243,893	$272,426	$275,752	$278,532	$279,797	$279,580	$2,972,807

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($23,438,186)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0% and 2.5%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	
3.	Less: Accumulated Depreciation	(92,424)	(96,029)	(99,634)	(103,239)	(106,844)	(110,449)	(114,054)	(117,659)	(121,264)	(124,869)	(128,474)	(132,079)	(135,684)	
4.	CWIP - Non-Interest Bearing	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	
5.	Net Investment (Lines 2 + 3 + 4)	$1,151,387	1,147,782	1,144,177	1,140,572	1,136,967	1,133,362	1,129,757	1,126,152	1,122,547	1,118,942	1,115,337	1,111,732	1,108,127	
6.	Average Net Investment		1,149,585	1,145,980	1,142,375	1,138,770	1,135,165	1,131,560	1,127,955	1,124,350	1,120,745	1,117,140	1,113,535	1,109,930	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,353	8,326	8,300	8,274	8,248	8,222	8,195	8,169	8,143	8,117	8,091	8,064	$98,502
	b. Debt Component Grossed Up For Taxes (C)		2,809	2,800	2,792	2,783	2,774	2,765	2,756	2,748	2,739	2,730	2,721	2,712	33,129
8.	Investment Expenses														
	a. Depreciation (D)		3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	43,260
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		14,767	14,731	14,697	14,662	14,627	14,592	14,556	14,522	14,487	14,452	14,417	14,381	174,891
	a. Recoverable Costs Allocated to Energy		14,767	14,731	14,697	14,662	14,627	14,592	14,556	14,522	14,487	14,452	14,417	14,381	174,891
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		14,738	14,702	14,666	14,637	14,601	14,570	14,525	14,484	14,462	14,435	14,416	14,380	174,616
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$14,738	$14,702	$14,666	$14,637	$14,601	$14,570	$14,525	$14,484	$14,462	$14,435	$14,416	$14,380	$174,616

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 345.81, and 315.40 ($1,169,053)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 4.0%, 3.5%, 3.0%, 3.3% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 25 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	*Investments*														
	a. 0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	970	0	0	0	0	0	0	0	0	970
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(38,451)	(38,373)	(38,283)	(38,181)	(38,105)	(38,045)	(37,970)	(37,858)	(37,744)	(37,647)	(37,558)	(37,456)	(37,356)	
3.	Total Working Capital Balance	($38,451)	(38,373)	(38,283)	(38,181)	(38,105)	(38,045)	(37,970)	(37,858)	(37,744)	(37,647)	(37,558)	(37,456)	(37,356)	
4.	Average Net Working Capital Balance		($38,412)	($38,328)	($38,232)	($38,143)	($38,075)	($38,008)	($37,914)	($37,801)	($37,696)	($37,603)	($37,507)	($37,406)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(279)	(278)	(278)	(277)	(277)	(276)	(275)	(275)	(274)	(273)	(273)	(272)	(3,307)
	b. Debt Component Grossed Up For Taxes (B)		(94)	(94)	(93)	(93)	(93)	(93)	(93)	(92)	(92)	(92)	(92)	(91)	(1,112)
6.	Total Return Component		(373)	(372)	(371)	(370)	(370)	(369)	(368)	(367)	(366)	(365)	(365)	(363)	(4,419)
7.	Expenses:														
	a. Gains		0	0	0	(970)	0	0	0	0	0	0	0	0	(970)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(43)	(114)	(114)	(81)	(45)	(60)	1,888	1,887	1,902	1,911	1,898	1,900	10,929
8.	Net Expenses (D)		(43)	(114)	(114)	(1,051)	(45)	(60)	1,888	1,887	1,902	1,911	1,898	1,900	9,959
9.	Total System Recoverable Expenses (Lines 6 + 8)		(416)	(486)	(485)	(1,421)	(415)	(429)	1,520	1,520	1,536	1,546	1,533	1,537	5,540
	a. Recoverable Costs Allocated to Energy		(416)	(486)	(485)	(1,421)	(415)	(429)	1,520	1,520	1,536	1,546	1,533	1,537	5,540
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9980321	0.9980282	0.9978870	0.9982619	0.9982101	0.9985125	0.9978957	0.9974053	0.9982786	0.9988268	0.9999083	0.9999272	
11.	*Demand Jurisdictional Factor*		*0.9958152*	*0.9958152*	*0.9958152*	*0.9958152*	*0.9958152*	*0.9958152*	*0.9958152*	*0.9958152*	*0.9958152*	*0.9958152*	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		(415)	(485)	(484)	(1,419)	(414)	(428)	1,517	1,516	1,533	1,544	1,533	1,537	5,535
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($415)	($485)	($484)	($1,419)	($414)	($428)	$1,517	$1,516	$1,533	$1,544	$1,533	$1,537	$5,535

Notes:

(A) Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(B) Line 4 x 2.9324% x 1/12.
(C) Line 6 is reported on Schedules 6E and 7E
(D) Line 8 is reported on Schedules 4E and 5E
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

DOCKET NO. 120007-EI
ECRC 2012 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 26 OF 26

Form 42 - 9E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2012 to December 2012

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base 2009 Test Year ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,384,999	40.29%	6.80%	2.7397%
Short Term Debt	7,905	0.23%	2.75%	0.0063%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	99,502	2.89%	6.07%	0.1754%
Common Equity	1,632,612	47.49%	11.25%	5.3426%
Deferred ITC - Weighted Cost	8,964	0.26%	9.19%	0.0239%
Accumulated Deferred Income Taxes (	303,629	8.83%	0.00%	0.0000%
Zero Cost ITCs				
Total	$ 3,437,611	100.00%		8.2879%

ITC split between Debt and Equity:

Long Term Debt	$ 1,384,999	Long Term Debt	45.78%
Short Term Debt	7,905	Short Term Debt	0.26%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,632,612	Equity - Common	53.96%
Total	$ 3,025,516	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0239% * 46.04%	0.0110%
Equity = .0239% * 53.96%	0.0129%
Weighted Cost	0.0239%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	5.3426%
Deferred ITC - Weighted Cost	0.0129%
	5.3555%
Times Tax Multiplier	1.628002
Total Equity Component	8.7188%

Total Debt Cost Rate:

Long Term Debt	2.7397%
Short Term Debt	0.0063%
Customer Deposits	0.1754%
Deferred ITC - Weighted Cost	0.0110%
Total Debt Component	2.9324%

Notes:
Column (1) - From Order No. PSC-09-0571-FOF-EI
Column (2) - Column (1) / Total Column (1)
Column (3) - From Order No. PSC-09-0571-FOF-EI
Column (4) - Column (2) x Column (3)

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ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2013 THROUGH DECEMBER 2013

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 34
PARTY Tampa Electric Company
DESCRIPTION Howard T. Bryant (HTB-3), Forms 42-1P
DATE Through 42-8P Forms for 1/13-12/13

Form 42 - 1P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2013 to December 2013

Line	Energy ($)	Demand ($)	Total ($)
1. Total Jurisdictional Revenue Requirements for the Projected period			
a. Projected O&M Activities (Form 42-2P, Lines 7, 8 & 9)	$24,994,511	$774,000	$25,768,511
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	60,128,229	129,004	60,257,233
c. Total Jurisdictional Revenue Requirements for the Projected period (Lines 1a +	85,122,740	903,004	86,025,744
2. True-up for Estimated Over/(Under) Recovery for the current period January 2012 to December 2012 (Form 42-2E, Line 5 + 6 + 10)	(11,705,941)	(48,885)	(11,754,826)
3. Final True-up for the period January 2011 to December 2011 (Form 42-1A, Line 3)	(3,217,929)	(14,522)	(3,232,451)
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2013 to December 2013 (Line 1 - Line 2- Line 3)	100,046,610	966,411	101,013,021
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$100,118,644	$967,107	$101,085,751

Notes Allocation to energy and demand in each period is in proportion to the respective period split of costs indicated on Lines 7 and 8 of Forms 42-5 and 42-7 of the actuals and estimates.

DOCKET NO. 120007-EI
ECRC 2013 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 1

Form 42 - 2P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

O&M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$416,800	$393,800	$499,300	$557,300	$428,300	$451,300	$462,800	$462,800	$439,800	$557,300	$416,800	$439,800	$5,526,100		$5,526,100
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	1,905	1,930	1,928	1,934	1,915	1,905	1,902	1,901	1,908	1,912	1,922	1,918	22,980		22,980
	d. Big Bend Units 1 & 2 FGD	850,000	1,055,000	820,000	895,000	860,000	910,000	945,000	945,000	895,000	900,000	1,100,000	905,000	11,080,000		11,080,000
	e. Big Bend PM Minimization and Monitoring	35,000	30,000	35,000	30,000	35,000	30,000	35,000	30,000	35,000	30,000	35,000	30,000	390,000		390,000
	f. Big Bend NO_x Emissions Reduction	25,000	25,000	25,000	25,000	25,000	25,000	50,000	25,000	50,000	25,000	50,000	25,000	375,000		375,000
	g. NPDES Annual Surveillance Fees (BB+BS+PK)	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	2,500	2,500	2,500	2,500	2,500	12,500	12,500	
	i. Polk NO_x Reduction	2,000	2,000	2,000	3,500	3,500	2,000	2,000	2,000	2,000	3,500	2,000	2,000	28,500		28,500
	j. Bayside SCR and Ammonia	8,000	8,000	10,500	8,000	8,000	10,500	8,000	8,000	10,500	8,000	8,000	10,500	106,000		106,000
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	o. Clean Water Act Section 316(b) Phase II Study	0	0	0	0	0	0	0	0	0	20,000	20,000	20,000	60,000	60,000	
	p. Arsenic Groundwater Standard Program	25,000	25,000	175,000	142,000	150,000	50,000	0	80,000	10,000	0	10,000		667,000	667,000	
	q. Big Bend 1 SCR	186,390	141,267	201,219	188,107	224,386	216,314	198,776	186,300	178,769	183,979	189,783	164,528	2,259,818		2,259,818
	r. Big Bend 2 SCR	200,753	201,851	230,545	196,969	229,612	204,193	244,823	213,776	172,324	215,069	215,345	181,149	2,506,409		2,506,409
	s. Big Bend 3 SCR	124,084	117,411	84,731	83,253	116,775	150,923	153,367	151,432	144,457	123,359	156,038	142,798	1,548,628		1,548,628
	t. Big Bend 4 SCR	87,122	69,319	76,814	89,990	89,973	95,019	95,501	88,627	86,735	101,783	77,428	82,765	1,041,076		1,041,076
	u. Clean Air Mercury Rule	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,666	1,666	1,666	1,666	20,000		20,000
	v. Greenhouse Gas Reduction Program	90,000	0	0	0	0	0	0	0	0	0	0	0	90,000		90,000
2.	Total of O&M Activities [1]	2,088,221	2,072,245	2,163,704	2,222,720	2,174,128	2,148,821	2,198,836	2,199,003	2,030,659	2,174,068	2,286,482	2,009,624	25,768,511	$774,000	$24,994,511
3.	Recoverable Costs Allocated to Energy	2,028,721	2,047,245	1,988,704	2,080,720	2,024,128	2,098,821	2,198,836	2,116,503	2,018,159	2,151,568	2,253,982	1,987,124	24,994,511		
4.	Recoverable Costs Allocated to Demand	59,500	25,000	175,000	142,000	150,000	50,000	0	82,500	12,500	22,500	32,500	22,500	774,000		
5.	Retail Energy Jurisdictional 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.	Retail Demand Jurisdictional 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			
7.	Jurisdictional Energy Recoverable Costs (A) [1]	2,028,721	2,047,245	1,988,704	2,080,720	2,024,128	2,098,821	2,198,836	2,116,503	2,018,159	2,151,568	2,253,982	1,987,124	24,994,511		
8.	Jurisdictional Demand Recoverable Costs (B) [1]	59,500	25,000	175,000	142,000	150,000	50,000	0	82,500	12,500	22,500	32,500	22,500	774,000		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) [1]	$2,088,221	$2,072,245	$2,163,704	$2,222,720	$2,174,128	$2,148,821	$2,198,836	$2,199,003	$2,030,659	$2,174,068	$2,286,482	$2,009,624	$25,768,511		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DOCKET NO. 120007-EI
ECRC 2013 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 2

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Form 42-3P

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$56,441	$56,289	$56,137	$55,985	$80,001	$116,023	$117,198	$117,561	$117,303	$117,046	$116,788	$116,532	$1,123,304		$1,123,304
	b	Big Bend Units 1 and 2 Flue Gas Conditioning	32,072	31,930	31,786	31,643	31,500	31,357	31,214	31,071	30,929	30,786	30,643	30,500	375,431		375,431
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,397	6,376	6,356	6,336	6,315	6,295	6,274	6,254	6,233	6,213	6,193	6,172	75,414		75,414
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,134	4,121	4,108	4,096	4,084	4,071	4,058	4,046	4,034	4,021	4,008	3,996	48,777	$ 48,777	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	6,799	6,778	6,757	6,737	6,716	6,696	6,676	6,654	6,634	6,614	6,593	6,573	80,227	80,227	
	f.	Big Bend Unit 1 Classifier Replacement	10,194	10,155	10,115	10,076	10,037	9,999	9,960	9,921	9,882	9,844	9,805	9,766	119,754		119,754
	g.	Big Bend Unit 2 Classifier Replacement	7,345	7,318	7,291	7,264	7,237	7,210	7,184	7,157	7,131	7,104	7,077	7,050	86,368		86,368
	h.	Big Bend Section 114 Mercury Testing Platform	1,055	1,052	1,050	1,048	1,045	1,043	1,040	1,037	1,035	1,032	1,029	1,027	12,493		12,493
	i.	Big Bend Units 1 & 2 FGD	684,205	682,029	679,852	677,676	675,499	673,324	671,147	669,414	668,123	674,809	686,506	686,342	8,128,926		8,128,926
	j.	Big Bend FGD Optimization and Utilization	183,809	183,407	183,007	182,606	182,205	181,804	181,403	181,002	180,601	180,200	179,799	179,399	2,179,242		2,179,242
	k.	Big Bend NO_x Emissions Reduction	60,388	60,298	60,208	60,117	60,027	59,938	59,847	59,757	59,666	59,576	59,487	59,396	718,705		718,705
	l.	Big Bend PM Minimization and Monitoring	99,603	109,231	124,497	139,762	153,920	187,270	188,137	188,392	188,674	188,907	189,324	189,957	1,947,674		1,947,674
	m.	Polk NO_x Emissions Reduction	14,062	14,023	13,984	13,945	13,906	13,867	13,827	13,788	13,749	13,710	13,671	13,632	166,164		166,164
	n.	Big Bend Unit 4 SOFA	24,375	24,318	24,261	24,205	24,148	24,091	24,035	23,978	23,921	23,864	23,808	23,751	288,755		288,755
	o.	Big Bend Unit 1 Pre-SCR	17,103	17,055	17,006	16,957	16,909	16,860	16,812	16,763	16,714	16,666	16,617	16,568	202,030		202,030
	p.	Big Bend Unit 2 Pre-SCR	16,193	16,150	16,106	16,063	16,020	15,977	15,934	15,890	15,847	15,804	15,761	15,718	191,463		191,463
	q.	Big Bend Unit 3 Pre-SCR	28,743	28,672	28,602	28,532	28,462	28,391	28,320	28,250	28,180	28,109	28,039	27,969	340,269		340,269
	r.	Big Bend Unit 1 SCR	954,784	952,097	949,411	946,724	946,252	945,779	943,092	942,619	942,147	939,460	938,988	940,730	11,342,083		11,342,083
	s.	Big Bend Unit 2 SCR	1,024,957	1,022,264	1,019,571	1,016,878	1,014,184	1,011,491	1,008,798	1,006,105	1,003,413	1,000,720	998,027	995,334	12,121,742		12,121,742
	t	Big Bend Unit 3 SCR	843,459	841,265	839,071	836,877	834,682	832,489	830,294	828,100	825,907	823,712	821,518	819,324	9,976,698		9,976,698
	u.	Big Bend Unit 4 SCR	633,551	631,957	630,363	628,769	627,176	625,582	623,988	622,394	620,800	619,206	617,613	616,019	7,497,418		7,497,418
	v.	Big Bend FGD System Reliability	259,180	258,715	258,250	257,785	257,321	256,856	256,391	255,927	255,462	254,998	254,533	254,068	3,079,486		3,079,486
	w	Clean Air Mercury Rule	13,403	13,371	13,339	13,307	13,275	13,243	13,211	13,180	13,148	13,115	13,084	13,052	158,728		158,728
	x.	SO_2 Emissions Allowances (B)	(331)	(330)	(329)	(328)	(328)	(327)	(326)	(325)	(324)	(324)	(323)	(323)	(3,918)		(3,918)
2.		Total Investment Projects - Recoverable Costs	4,981,921	4,978,541	4,980,799	4,983,060	5,010,593	5,069,329	5,058,514	5,048,935	5,039,209	5,035,192	5,038,588	5,032,552	60,257,233	$ 129,004	$ 60,128,229
3.		Recoverable Costs Allocated to Energy	4,970,988	4,967,642	4,969,934	4,972,227	4,999,793	5,058,562	5,047,780	5,038,235	5,028,541	5,024,557	5,027,987	5,021,983	60,128,229		60,128,229
4.		Recoverable Costs Allocated to Demand	10,933	10,899	10,865	10,833	10,800	10,767	10,734	10,700	10,668	10,635	10,601	10,569	129,004	129,004	
5.		Retail Energy Jurisdictional 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.		Retail Demand Jurisdictional 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			
7.		Jurisdictional Energy Recoverable Costs (C)	4,970,988	4,967,642	4,969,934	4,972,227	4,999,793	5,058,562	5,047,780	5,038,235	5,028,541	5,024,557	5,027,987	5,021,983	60,128,229		
8.		Jurisdictional Demand Recoverable Costs (D)	10,933	10,899	10,865	10,833	10,800	10,767	10,734	10,700	10,668	10,635	10,601	10,569	129,004		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$4,981,921	$4,978,541	$4,980,799	$4,983,060	$5,010,593	$5,069,329	$5,058,514	$5,048,935	$5,039,209	$5,035,192	$5,038,588	$5,032,552	$60,257,233		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Project's Total Return Component on Form 42-4P, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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ECRC 2013 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	436,324	$155,000	$95,000	$0	$0	$0	$0	$0	$686,324
	b. Clearings to Plant		0	0	0	0	5,457,756	155,000	95,000	0	0	0	0	0	$5,707,756
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - (G)		645,960	725,000	725,000	725,000	0	0	0	0	0	0	0	0	$2,820,960
2.	Plant-in-Service/Depreciation Base (A)	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$13,697,414	$13,852,414	$13,947,414	$13,947,414	$13,947,414	$13,947,414	$13,947,414	$13,947,414	
3.	Less: Accumulated Depreciation	(3,796,317)	(3,813,483)	(3,830,649)	(3,847,815)	(3,864,981)	(3,882,147)	(3,910,683)	(3,939,542)	(3,968,599)	(3,997,656)	(4,026,713)	(4,055,770)	(4,084,827)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,443,341	4,426,175	4,409,009	4,391,843	4,374,677	9,815,267	9,941,731	10,007,872	9,978,815	9,949,758	9,920,701	9,891,644	9,862,587	
6.	Average Net Investment		4,434,758	4,417,592	4,400,426	4,383,260	7,094,972	9,878,499	9,974,802	9,993,344	9,964,287	9,935,230	9,906,173	9,877,116	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		29,082	28,969	28,857	28,744	46,527	64,781	65,412	65,534	65,343	65,153	64,962	64,772	$618,136
	b. Debt Component Grossed Up For Taxes (C)		10,193	10,154	10,114	10,075	16,308	22,706	22,927	22,970	22,903	22,836	22,769	22,703	216,658
8.	Investment Expenses														
	a. Depreciation (D)		17,166	17,166	17,166	17,166	17,166	28,536	28,859	29,057	29,057	29,057	29,057	29,057	288,510
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		56,441	56,289	56,137	55,985	80,001	116,023	117,198	117,561	117,303	117,046	116,788	116,532	1,123,304
	a. Recoverable Costs Allocated to Energy		56,441	56,289	56,137	55,985	80,001	116,023	117,198	117,561	117,303	117,046	116,788	116,532	1,123,304
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		56,441	56,289	56,137	55,985	80,001	116,023	117,198	117,561	117,303	117,046	116,788	116,532	1,123,304
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$56,441	$56,289	$56,137	$55,985	$80,001	$116,023	$117,198	$117,561	$117,303	$117,046	$116,788	$116,532	$1,123,304

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Line 1d - Expenditures include AFUDC and are for tracking purposes only. Depreciation and Return are not calculated until the project goes in-service.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(3,210,818)	(3,226,959)	(3,243,100)	(3,259,241)	(3,275,382)	(3,291,523)	(3,307,664)	(3,323,805)	(3,339,946)	(3,356,087)	(3,372,228)	(3,388,369)	(3,404,510)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,806,916	1,790,775	1,774,634	1,758,493	1,742,352	1,726,211	1,710,070	1,693,929	1,677,788	1,661,647	1,645,506	1,629,365	1,613,224	
6.	Average Net Investment		1,798,846	1,782,705	1,766,564	1,750,423	1,734,282	1,718,141	1,702,000	1,685,859	1,669,718	1,653,577	1,637,436	1,621,295	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		11,796	11,691	11,585	11,479	11,373	11,267	11,161	11,055	10,950	10,844	10,738	10,632	$134,571
	b. Debt Component Grossed Up For Taxes (C)		4,135	4,098	4,060	4,023	3,986	3,949	3,912	3,875	3,838	3,801	3,764	3,727	47,168
8.	Investment Expenses														
	a. Depreciation (D)		16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	193,692
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		32,072	31,930	31,786	31,643	31,500	31,357	31,214	31,071	30,929	30,786	30,643	30,500	375,431
	a. Recoverable Costs Allocated to Energy		32,072	31,930	31,786	31,643	31,500	31,357	31,214	31,071	30,929	30,786	30,643	30,500	375,431
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		32,072	31,930	31,786	31,643	31,500	31,357	31,214	31,071	30,929	30,786	30,643	30,500	375,431
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$32,072	$31,930	$31,786	$31,643	$31,500	$31,357	$31,214	$31,071	$30,929	$30,786	$30,643	$30,500	$375,431

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rates are 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(403,565)	(405,875)	(408,185)	(410,495)	(412,805)	(415,115)	(417,425)	(419,735)	(422,045)	(424,355)	(426,665)	(428,975)	(431,285)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$462,646	460,336	458,026	455,716	453,406	451,096	448,786	446,476	444,166	441,856	439,546	437,236	434,926	
6.	Average Net Investment		461,491	459,181	456,871	454,561	452,251	449,941	447,631	445,321	443,011	440,701	438,391	436,081	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,026	3,011	2,996	2,981	2,966	2,951	2,935	2,920	2,905	2,890	2,875	2,860	$35,316
	b. Debt Component Grossed Up For Taxes (C)		1,061	1,055	1,050	1,045	1,039	1,034	1,029	1,024	1,018	1,013	1,008	1,002	12,378
8.	Investment Expenses														
	a. Depreciation (D)		2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,397	6,376	6,356	6,336	6,315	6,295	6,274	6,254	6,233	6,213	6,193	6,172	75,414
	a. Recoverable Costs Allocated to Energy		6,397	6,376	6,356	6,336	6,315	6,295	6,274	6,254	6,233	6,213	6,193	6,172	75,414
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		6,397	6,376	6,356	6,336	6,315	6,295	6,274	6,254	6,233	6,213	6,193	6,172	75,414
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,397	$6,376	$6,356	$6,336	$6,315	$6,295	$6,274	$6,254	$6,233	$6,213	$6,193	$6,172	$75,414

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	Projected Janaury	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(189,352)	(190,762)	(192,172)	(193,582)	(194,992)	(196,402)	(197,812)	(199,222)	(200,632)	(202,042)	(203,452)	(204,862)	(206,272)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$308,226	306,816	305,406	303,996	302,586	301,176	299,766	298,356	296,946	295,536	294,126	292,716	291,306	
6.	Average Net Investment		307,521	306,111	304,701	303,291	301,881	300,471	299,061	297,651	296,241	294,831	293,421	292,011	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,017	2,007	1,998	1,989	1,980	1,970	1,961	1,952	1,943	1,933	1,924	1,915	$23,589
	b. Debt Component Grossed Up For Taxes (C)		707	704	700	697	694	691	687	684	681	678	674	671	8,268
8.	Investment Expenses														
	a. Depreciation (D)		1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	16,920
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,134	4,121	4,108	4,096	4,084	4,071	4,058	4,046	4,034	4,021	4,008	3,996	48,777
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,134	4,121	4,108	4,096	4,084	4,071	4,058	4,046	4,034	4,021	4,008	3,996	48,777
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,134	4,121	4,108	4,096	4,084	4,071	4,058	4,046	4,034	4,021	4,008	3,996	48,777
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,134	$4,121	$4,108	$4,096	$4,084	$4,071	$4,058	$4,046	$4,034	$4,021	$4,008	$3,996	$48,777

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(311,452)	(313,771)	(316,090)	(318,409)	(320,728)	(323,047)	(325,366)	(327,685)	(330,004)	(332,323)	(334,642)	(336,961)	(339,280)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$506,949	504,630	502,311	499,992	497,673	495,354	493,035	490,716	488,397	486,078	483,759	481,440	479,121	
6.	Average Net Investment		505,790	503,471	501,152	498,833	496,514	494,195	491,876	489,557	487,238	484,919	482,600	480,281	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,317	3,302	3,286	3,271	3,256	3,241	3,226	3,210	3,195	3,180	3,165	3,150	$38,799
	b. Debt Component Grossed Up For Taxes (C)		1,163	1,157	1,152	1,147	1,141	1,136	1,131	1,125	1,120	1,115	1,109	1,104	13,600
8.	Investment Expenses														
	a. Depreciation (D)		2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	27,828
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,799	6,778	6,757	6,737	6,716	6,696	6,676	6,654	6,634	6,614	6,593	6,573	80,227
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		6,799	6,778	6,757	6,737	6,716	6,696	6,676	6,654	6,634	6,614	6,593	6,573	80,227
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		6,799	6,778	6,757	6,737	6,716	6,696	6,676	6,654	6,634	6,614	6,593	6,573	80,227
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,799	$6,778	$6,757	$6,737	$6,716	$6,696	$6,676	$6,654	$6,634	$6,614	$6,593	$6,573	$80,227

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(658,568)	(662,956)	(667,344)	(671,732)	(676,120)	(680,508)	(684,896)	(689,284)	(693,672)	(698,060)	(702,448)	(706,836)	(711,224)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$657,689	653,301	648,913	644,525	640,137	635,749	631,361	626,973	622,585	618,197	613,809	609,421	605,033	
6.	Average Net Investment		655,495	651,107	646,719	642,331	637,943	633,555	629,167	624,779	620,391	616,003	611,615	607,227	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,299	4,270	4,241	4,212	4,183	4,155	4,126	4,097	4,068	4,040	4,011	3,982	$49,684
	b. Debt Component Grossed Up For Taxes (C)		1,507	1,497	1,486	1,476	1,466	1,456	1,446	1,436	1,426	1,416	1,406	1,396	17,414
8.	Investment Expenses														
	a. Depreciation (D)		4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,194	10,155	10,115	10,076	10,037	9,999	9,960	9,921	9,882	9,844	9,805	9,766	119,754
	a. Recoverable Costs Allocated to Energy		10,194	10,155	10,115	10,076	10,037	9,999	9,960	9,921	9,882	9,844	9,805	9,766	119,754
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		10,194	10,155	10,115	10,076	10,037	9,999	9,960	9,921	9,882	9,844	9,805	9,766	119,754
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,194	$10,155	$10,115	$10,076	$10,037	$9,999	$9,960	$9,921	$9,882	$9,844	$9,805	$9,766	$119,754

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2013 PROJECTION FILING
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(496,710)	(499,746)	(502,782)	(505,818)	(508,854)	(511,890)	(514,926)	(517,962)	(520,998)	(524,034)	(527,070)	(530,106)	(533,142)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$488,084	485,048	482,012	478,976	475,940	472,904	469,868	466,832	463,796	460,760	457,724	454,688	451,652	
6.	Average Net Investment		486,566	483,530	480,494	477,458	474,422	471,386	468,350	465,314	462,278	459,242	456,206	453,170	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,191	3,171	3,151	3,131	3,111	3,091	3,071	3,051	3,032	3,012	2,992	2,972	$36,976
	b. Debt Component Grossed Up For Taxes (C)		1,118	1,111	1,104	1,097	1,090	1,083	1,077	1,070	1,063	1,056	1,049	1,042	12,960
8.	Investment Expenses														
	a. Depreciation (D)		3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	36,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,345	7,318	7,291	7,264	7,237	7,210	7,184	7,157	7,131	7,104	7,077	7,050	86,368
	a. Recoverable Costs Allocated to Energy		7,345	7,318	7,291	7,264	7,237	7,210	7,184	7,157	7,131	7,104	7,077	7,050	86,368
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		7,345	7,318	7,291	7,264	7,237	7,210	7,184	7,157	7,131	7,104	7,077	7,050	86,368
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,345	$7,318	$7,291	$7,264	$7,237	$7,210	$7,184	$7,157	$7,131	$7,104	$7,077	$7,050	$86,368

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(34,387)	(34,679)	(34,971)	(35,263)	(35,555)	(35,847)	(36,139)	(36,431)	(36,723)	(37,015)	(37,307)	(37,599)	(37,891)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$86,350	86,058	85,766	85,474	85,182	84,890	84,598	84,306	84,014	83,722	83,430	83,138	82,846	
6.	Average Net Investment		86,204	85,912	85,620	85,328	85,036	84,744	84,452	84,160	83,868	83,576	83,284	82,992	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		565	563	561	560	558	556	554	552	550	548	546	544	$6,657
	b. Debt Component Grossed Up For Taxes (C)		198	197	197	196	195	195	194	193	193	192	191	191	2,332
8.	Investment Expenses														
	a. Depreciation (D)		292	292	292	292	292	292	292	292	292	292	292	292	3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,055	1,052	1,050	1,048	1,045	1,043	1,040	1,037	1,035	1,032	1,029	1,027	12,493
	a. Recoverable Costs Allocated to Energy		1,055	1,052	1,050	1,048	1,045	1,043	1,040	1,037	1,035	1,032	1,029	1,027	12,493
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		1,055	1,052	1,050	1,048	1,045	1,043	1,040	1,037	1,035	1,032	1,029	1,027	12,493
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,055	$1,052	$1,050	$1,048	$1,045	$1,043	$1,040	$1,037	$1,035	$1,032	$1,029	$1,027	$12,493

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$100,000	$100,000	$150,000	$118,135	$180,000	$648,135
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	1,801,284	18,135	734,693	2,554,112
	c. Retirements		0	0	0	0	0	0	0	0	0	0		0	
	d. Other - (G)		$0	$0	$0	$0	$10,000	$50,000	$350,000	$350,000	$371,558	$53,135	$80,000	$2,615	1,267,308
2.	Plant-in-Service/Depreciation Base (A)	$89,357,235	$89,357,235	$89,357,235	$89,357,235	$89,357,235	$89,357,235	$89,357,235	$89,357,235	$89,357,235	$89,357,235	$91,158,519	$91,176,654	$91,911,347	
3.	Less: Accumulated Depreciation	(39,724,383)	(39,970,115)	(40,215,847)	(40,461,579)	(40,707,311)	(40,953,043)	(41,198,775)	(41,444,507)	(41,690,239)	(41,935,971)	(42,181,703)	(42,432,389)	(42,683,125)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	100,000	200,000	300,000	400,000	0	
5.	Net Investment (Lines 2 + 3 + 4)	$49,632,852	49,387,120	49,141,388	48,895,656	48,649,924	48,404,192	48,158,460	47,912,728	47,766,996	47,621,264	49,276,816	49,144,265	49,228,222	
6.	Average Net Investment		49,509,986	49,264,254	49,018,522	48,772,790	48,527,058	48,281,326	48,035,594	47,839,862	47,694,130	48,449,040	49,210,541	49,186,244	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		324,674	323,063	321,451	319,840	318,228	316,617	315,005	313,722	312,766	317,717	322,710	322,551	$3,828,344
	b. Debt Component Grossed Up For Taxes (C)		113,799	113,234	112,669	112,104	111,539	110,975	110,410	109,960	109,625	111,360	113,110	113,055	1,341,840
8.	Investment Expenses														
	a. Depreciation (D)		245,732	245,732	245,732	245,732	245,732	245,732	245,732	245,732	245,732	245,732	250,686	250,736	2,958,742
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		684,205	682,029	679,852	677,676	675,499	673,324	671,147	669,414	668,123	674,809	686,506	686,342	8,128,926
	a. Recoverable Costs Allocated to Energy		684,205	682,029	679,852	677,676	675,499	673,324	671,147	669,414	668,123	674,809	686,506	686,342	8,128,926
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		684,205	682,029	679,852	677,676	675,499	673,324	671,147	669,414	668,123	674,809	686,506	686,342	8,128,926
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$684,205	$682,029	$679,852	$677,676	$675,499	$673,324	$671,147	$669,414	$668,123	$674,809	$686,506	$686,342	$8,128,926

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rates are 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Line 1d - Expenditures include AFUDC and are for tracking purposes only. Depreciation and Return are not calculated until the project goes in-service.

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ECRC 2013 PROJECTION FILING
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(6,074,485)	(6,119,759)	(6,165,033)	(6,210,307)	(6,255,581)	(6,300,855)	(6,346,129)	(6,391,403)	(6,436,677)	(6,481,951)	(6,527,225)	(6,572,499)	(6,617,773)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$15,665,252	15,619,978	15,574,704	15,529,430	15,484,156	15,438,882	15,393,608	15,348,334	15,303,060	15,257,786	15,212,512	15,167,238	15,121,964	
6.	Average Net Investment		15,642,615	15,597,341	15,552,067	15,506,793	15,461,519	15,416,245	15,370,971	15,325,697	15,280,423	15,235,149	15,189,875	15,144,601	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		102,580	102,283	101,987	101,690	101,393	101,096	100,799	100,502	100,205	99,908	99,611	99,315	$1,211,369
	b. Debt Component Grossed Up For Taxes (C)		35,955	35,850	35,746	35,642	35,538	35,434	35,330	35,226	35,122	35,018	34,914	34,810	424,585
8.	Investment Expenses														
	a. Depreciation (D)		45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	45,274	543,288
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		183,809	183,407	183,007	182,606	182,205	181,804	181,403	181,002	180,601	180,200	179,799	179,399	2,179,242
	a. Recoverable Costs Allocated to Energy		183,809	183,407	183,007	182,606	182,205	181,804	181,403	181,002	180,601	180,200	179,799	179,399	2,179,242
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		183,809	183,407	183,007	182,606	182,205	181,804	181,403	181,002	180,601	180,200	179,799	179,399	2,179,242
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$183,809	$183,407	$183,007	$182,606	$182,205	$181,804	$181,403	$181,002	$180,601	$180,200	$179,799	$179,399	$2,179,242

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rates are 2.0% and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	2,483,019	2,472,835	2,462,651	2,452,467	2,442,283	2,432,099	2,421,915	2,411,731	2,401,547	2,391,363	2,381,179	2,370,995	2,360,811	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,673,871	5,663,687	5,653,503	5,643,319	5,633,135	5,622,951	5,612,767	5,602,583	5,592,399	5,582,215	5,572,031	5,561,847	5,551,663	
6.	Average Net Investment		5,668,779	5,658,595	5,648,411	5,638,227	5,628,043	5,617,859	5,607,675	5,597,491	5,587,307	5,577,123	5,566,939	5,556,755	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		37,174	37,108	37,041	36,974	36,907	36,841	36,774	36,707	36,640	36,573	36,507	36,440	$441,686
	b. Debt Component Grossed Up For Taxes (C)		13,030	13,006	12,983	12,959	12,936	12,913	12,889	12,866	12,842	12,819	12,796	12,772	154,811
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		60,388	60,298	60,208	60,117	60,027	59,938	59,847	59,757	59,666	59,576	59,487	59,396	718,705
	a. Recoverable Costs Allocated to Energy		60,388	60,298	60,208	60,117	60,027	59,938	59,847	59,757	59,666	59,576	59,487	59,396	718,705
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		60,388	60,298	60,208	60,117	60,027	59,938	59,847	59,757	59,666	59,576	59,487	59,396	718,705
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$60,388	$60,298	$60,208	$60,117	$60,027	$59,938	$59,847	$59,757	$59,666	$59,576	$59,487	$59,396	$718,705

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rates are 4.0%, 3.7%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
Janaury 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$476,900	$1,750,000	$1,750,000	$1,750,000	$1,500,000	$150,000	$50,000	$80,000	$70,000	$76,000	$125,000	$125,000	$7,902,900
	b. Clearings to Plant		0	0	0	0	8,797,800	150,000	50,000	30,000	20,000	0	0	426,000	$9,473,800
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$8,519,606	$17,317,406	$17,467,406	$17,517,406	$17,547,406	$17,567,406	$17,567,406	$17,567,406	$17,993,406	
3.	Less: Accumulated Depreciation	(2,038,295)	(2,064,590)	(2,090,885)	(2,117,180)	(2,143,475)	(2,169,770)	(2,222,458)	(2,275,596)	(2,328,884)	(2,382,262)	(2,435,700)	(2,489,138)	(2,542,576)	
4.	CWIP - Non-Interest Bearing	1,570,900	2,047,800	3,797,800	5,547,800	7,297,800	0	0	0	50,000	100,000	176,000	301,000	0	
5.	Net Investment (Lines 2 + 3 + 4)	$8,052,211	8,502,816	10,226,521	11,950,226	13,673,931	15,147,636	15,244,948	15,241,810	15,268,522	15,285,144	15,307,706	15,379,268	15,450,830	
6.	Average Net Investment		8,277,514	9,364,669	11,088,374	12,812,079	14,410,784	15,196,292	15,243,379	15,255,166	15,276,833	15,296,425	15,343,487	15,415,049	
7.	Return on Average Net investment														
	a. Equity Component Grossed Up For Taxes (B)		54,282	61,411	72,715	84,018	94,502	99,653	99,962	100,040	100,182	100,310	100,619	101,088	$1,068,782
	b. Debt Component Grossed Up For Taxes (C)		19,026	21,525	25,487	29,449	33,123	34,929	35,037	35,064	35,114	35,159	35,267	35,431	374,611
8.	Investment Expenses														
	a. Depreciation (D)		26,295	26,295	26,295	26,295	26,295	52,688	53,138	53,288	53,378	53,438	53,438	53,438	504,281
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		99,603	109,231	124,497	139,762	153,920	187,270	188,137	188,392	188,674	188,907	189,324	189,957	1,947,674
	a. Recoverable Costs Allocated to Energy		99,603	109,231	124,497	139,762	153,920	187,270	188,137	188,392	188,674	188,907	189,324	189,957	1,947,674
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		99,603	109,231	124,497	139,762	153,920	187,270	188,137	188,392	188,674	188,907	189,324	189,957	1,947,674
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$99,603	$109,231	$124,497	$139,762	$153,920	$187,270	$188,137	$188,392	$188,674	$188,907	$189,324	$189,957	$1,947,674

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.40 ($176,000), 315.41 ($142,504), 315.42 ($125,000), 315.44 ($351,594), and 315.43 ($9,576,354)
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rates are 4.0%, 3.7%, 3.5%, 3.7%, 3.5%, 3.3%, 3.2%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(470,970)	(475,394)	(479,818)	(484,242)	(488,666)	(493,090)	(497,514)	(501,938)	(506,362)	(510,786)	(515,210)	(519,634)	(524,058)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,090,503	1,086,079	1,081,655	1,077,231	1,072,807	1,068,383	1,063,959	1,059,535	1,055,111	1,050,687	1,046,263	1,041,839	1,037,415	
6.	Average Net Investment		1,088,291	1,083,867	1,079,443	1,075,019	1,070,595	1,066,171	1,061,747	1,057,323	1,052,899	1,048,475	1,044,051	1,039,627	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		7,137	7,108	7,079	7,050	7,021	6,992	6,963	6,934	6,905	6,876	6,847	6,818	$83,730
	b. Debt Component Grossed Up For Taxes (C)		2,501	2,491	2,481	2,471	2,461	2,451	2,440	2,430	2,420	2,410	2,400	2,390	29,346
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		14,062	14,023	13,984	13,945	13,906	13,867	13,827	13,788	13,749	13,710	13,671	13,632	166,164
	a. Recoverable Costs Allocated to Energy		14,062	14,023	13,984	13,945	13,906	13,867	13,827	13,788	13,749	13,710	13,671	13,632	166,164
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		14,062	14,023	13,984	13,945	13,906	13,867	13,827	13,788	13,749	13,710	13,671	13,632	166,164
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$14,062	$14,023	$13,984	$13,945	$13,906	$13,867	$13,827	$13,788	$13,749	$13,710	$13,671	$13,632	$166,164

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(525,614)	(532,011)	(538,408)	(544,805)	(551,202)	(557,599)	(563,996)	(570,393)	(576,790)	(583,187)	(589,584)	(595,981)	(602,378)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,033,116	2,026,719	2,020,322	2,013,925	2,007,528	2,001,131	1,994,734	1,988,337	1,981,940	1,975,543	1,969,146	1,962,749	1,956,352	
6.	Average Net Investment		2,029,918	2,023,521	2,017,124	2,010,727	2,004,330	1,997,933	1,991,536	1,985,139	1,978,742	1,972,345	1,965,948	1,959,551	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		13,312	13,270	13,228	13,186	13,144	13,102	13,060	13,018	12,976	12,934	12,892	12,850	$156,972
	b. Debt Component Grossed Up For Taxes (C)		4,666	4,651	4,636	4,622	4,607	4,592	4,578	4,563	4,548	4,533	4,519	4,504	55,019
8.	Investment Expenses														
	a. Depreciation (D)		6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		24,375	24,318	24,261	24,205	24,148	24,091	24,035	23,978	23,921	23,864	23,808	23,751	288,755
	a. Recoverable Costs Allocated to Energy		24,375	24,318	24,261	24,205	24,148	24,091	24,035	23,978	23,921	23,864	23,808	23,751	288,755
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		24,375	24,318	24,261	24,205	24,148	24,091	24,035	23,978	23,921	23,864	23,808	23,751	288,755
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$24,375	$24,318	$24,261	$24,205	$24,148	$24,091	$24,035	$23,978	$23,921	$23,864	$23,808	$23,751	$288,755

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(335,809)	(341,306)	(346,803)	(352,300)	(357,797)	(363,294)	(368,791)	(374,288)	(379,785)	(385,282)	(390,779)	(396,276)	(401,773)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,313,312	1,307,815	1,302,318	1,296,821	1,291,324	1,285,827	1,280,330	1,274,833	1,269,336	1,263,839	1,258,342	1,252,845	1,247,348	
6.	Average Net Investment		1,310,564	1,305,067	1,299,570	1,294,073	1,288,576	1,283,079	1,277,582	1,272,085	1,266,588	1,261,091	1,255,594	1,250,097	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,594	8,558	8,522	8,486	8,450	8,414	8,378	8,342	8,306	8,270	8,234	8,198	$100,752
	b. Debt Component Grossed Up For Taxes (C)		3,012	3,000	2,987	2,974	2,962	2,949	2,937	2,924	2,911	2,899	2,886	2,873	35,314
8.	Investment Expenses														
	a. Depreciation (D)		5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,103	17,055	17,006	16,957	16,909	16,860	16,812	16,763	16,714	16,666	16,617	16,568	202,030
	a. Recoverable Costs Allocated to Energy		17,103	17,055	17,006	16,957	16,909	16,860	16,812	16,763	16,714	16,666	16,617	16,568	202,030
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		17,103	17,055	17,006	16,957	16,909	16,860	16,812	16,763	16,714	16,666	16,617	16,568	202,030
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,103	$17,055	$17,006	$16,957	$16,909	$16,860	$16,812	$16,763	$16,714	$16,666	$16,617	$16,568	$202,030

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(301,700)	(306,577)	(311,454)	(316,331)	(321,208)	(326,085)	(330,962)	(335,839)	(340,716)	(345,593)	(350,470)	(355,347)	(360,224)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,280,187	1,275,310	1,270,433	1,265,556	1,260,679	1,255,802	1,250,925	1,246,048	1,241,171	1,236,294	1,231,417	1,226,540	1,221,663	
6.	Average Net Investment		1,277,749	1,272,872	1,267,995	1,263,118	1,258,241	1,253,364	1,248,487	1,243,610	1,238,733	1,233,856	1,228,979	1,224,102	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,379	8,347	8,315	8,283	8,251	8,219	8,187	8,155	8,123	8,091	8,059	8,027	$98,436
	b. Debt Component Grossed Up For Taxes (C)		2,937	2,926	2,914	2,903	2,892	2,881	2,870	2,858	2,847	2,836	2,825	2,814	34,503
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		16,193	16,150	16,106	16,063	16,020	15,977	15,934	15,890	15,847	15,804	15,761	15,718	191,463
	a. Recoverable Costs Allocated to Energy		16,193	16,150	16,106	16,063	16,020	15,977	15,934	15,890	15,847	15,804	15,761	15,718	191,463
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		16,193	16,150	16,106	16,063	16,020	15,977	15,934	15,890	15,847	15,804	15,761	15,718	191,463
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,193	$16,150	$16,106	$16,063	$16,020	$15,977	$15,934	$15,890	$15,847	$15,804	$15,761	$15,718	$191,463

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(355,022)	(362,975)	(370,928)	(378,881)	(386,834)	(394,787)	(402,740)	(410,693)	(418,646)	(426,599)	(434,552)	(442,505)	(450,458)	
4.	CWIP - Non-interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,351,485	2,343,532	2,335,579	2,327,626	2,319,673	2,311,720	2,303,767	2,295,814	2,287,861	2,279,908	2,271,955	2,264,002	2,256,049	
6.	Average Net Investment		2,347,509	2,339,556	2,331,603	2,323,650	2,315,697	2,307,744	2,299,791	2,291,838	2,283,885	2,275,932	2,267,979	2,260,026	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,394	15,342	15,290	15,238	15,186	15,134	15,081	15,029	14,977	14,925	14,873	14,821	$181,290
	b. Debt Component Grossed Up For Taxes (C)		5,396	5,377	5,359	5,341	5,323	5,304	5,286	5,268	5,250	5,231	5,213	5,195	63,543
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		28,743	28,672	28,602	28,532	28,462	28,391	28,320	28,250	28,180	28,109	28,039	27,969	340,269
	a. Recoverable Costs Allocated to Energy		28,743	28,672	28,602	28,532	28,462	28,391	28,320	28,250	28,180	28,109	28,039	27,969	340,269
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		28,743	28,672	28,602	28,532	28,462	28,391	28,320	28,250	28,180	28,109	28,039	27,969	340,269
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$28,743	$28,672	$28,602	$28,532	$28,462	$28,391	$28,320	$28,250	$28,180	$28,109	$28,039	$27,969	$340,269

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$500,000	$0	$0	$500,000	$0	$0	$500,000	$500,000	$2,000,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	2,000,000	$2,000,000
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$84,099,314	$86,099,314	
3.	Less: Accumulated Depreciation	(10,392,573)	(10,695,935)	(10,999,297)	(11,302,659)	(11,606,021)	(11,909,383)	(12,212,745)	(12,516,107)	(12,819,469)	(13,122,831)	(13,426,193)	(13,729,555)	(14,032,917)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	500,000	500,000	500,000	1,000,000	1,000,000	1,000,000	1,500,000	0	
5.	Net Investment (Lines 2 + 3 + 4)	$73,706,741	73,403,379	73,100,017	72,796,655	72,493,293	72,689,931	72,386,569	72,083,207	72,279,845	71,976,483	71,673,121	71,869,759	72,066,397	
6.	Average Net Investment		73,555,060	73,251,698	72,948,336	72,644,974	72,591,612	72,538,250	72,234,888	72,181,526	72,128,164	71,824,802	71,771,440	71,968,078	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		482,356	480,366	478,377	476,388	476,038	475,688	473,698	473,348	472,998	471,009	470,659	471,949	$5,702,874
	b. Debt Component Grossed Up For Taxes (C)		169,066	168,369	167,672	166,974	166,852	166,729	166,032	165,909	165,787	165,089	164,967	165,419	1,998,865
8.	Investment Expenses														
	a. Depreciation (D)		303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	303,362	3,640,344
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		954,784	952,097	949,411	946,724	946,252	945,779	943,092	942,619	942,147	939,460	938,988	940,730	11,342,083
	a. Recoverable Costs Allocated to Energy		954,784	952,097	949,411	946,724	946,252	945,779	943,092	942,619	942,147	939,460	938,988	940,730	11,342,083
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		954,784	952,097	949,411	946,724	946,252	945,779	943,092	942,619	942,147	939,460	938,988	940,730	11,342,083
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$954,784	$952,097	$949,411	$946,724	$946,252	$945,779	$943,092	$942,619	$942,147	$939,460	$938,988	$940,730	$11,342,083

Notes:
(A) Applicable depreciable base for Big Bend; account 311.51 ($22,915,197), 312.51 ($48,249,476), 315.51 ($14,063,245), and 316.51 ($871,396).
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8% and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	$94,048,278	
3.	Less: Accumulated Depreciation	(12,498,395)	(12,802,472)	(13,106,549)	(13,410,626)	(13,714,703)	(14,018,780)	(14,322,857)	(14,626,934)	(14,931,011)	(15,235,088)	(15,539,165)	(15,843,242)	(16,147,319)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$81,549,883	81,245,806	80,941,729	80,637,652	80,333,575	80,029,498	79,725,421	79,421,344	79,117,267	78,813,190	78,509,113	78,205,036	77,900,959	
6.	Average Net Investment		81,397,845	81,093,768	80,789,691	80,485,614	80,181,537	79,877,460	79,573,383	79,269,306	78,965,229	78,661,152	78,357,075	78,052,998	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		533,787	531,793	529,799	527,805	525,810	523,816	521,822	519,828	517,834	515,840	513,846	511,852	$6,273,832
	b. Debt Component Grossed Up For Taxes (C)		187,093	186,394	185,695	184,996	184,297	183,598	182,899	182,200	181,502	180,803	180,104	179,405	2,198,986
8.	Investment Expenses														
	a. Depreciation (D)		304,077	304,077	304,077	304,077	304,077	304,077	304,077	304,077	304,077	304,077	304,077	304,077	3,648,924
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,024,957	1,022,264	1,019,571	1,016,878	1,014,184	1,011,491	1,008,798	1,006,105	1,003,413	1,000,720	998,027	995,334	12,121,742
	a. Recoverable Costs Allocated to Energy		1,024,957	1,022,264	1,019,571	1,016,878	1,014,184	1,011,491	1,008,798	1,006,105	1,003,413	1,000,720	998,027	995,334	12,121,742
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		1,024,957	1,022,264	1,019,571	1,016,878	1,014,184	1,011,491	1,008,798	1,006,105	1,003,413	1,000,720	998,027	995,334	12,121,742
13.	Retail Demand-Relatad Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,024,957	$1,022,264	$1,019,571	$1,016,878	$1,014,184	$1,011,491	$1,008,798	$1,006,105	$1,003,413	$1,000,720	$998,027	$995,334	$12,121,742

Notes:
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52($51,966,366), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	$80,433,979	
3.	Less. Accumulated Depreciation	(13,045,725)	(13,293,474)	(13,541,223)	(13,788,972)	(14,036,721)	(14,284,470)	(14,532,219)	(14,779,968)	(15,027,717)	(15,275,466)	(15,523,215)	(15,770,964)	(16,018,713)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$67,388,254	67,140,505	66,892,756	66,645,007	66,397,258	66,149,509	65,901,760	65,654,011	65,406,262	65,158,513	64,910,764	64,663,015	64,415,266	
6.	Average Net Investment		67,264,380	67,016,631	66,768,882	66,521,133	66,273,384	66,025,635	65,777,886	65,530,137	65,282,388	65,034,639	64,786,890	64,539,141	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		441,103	439,478	437,854	436,229	434,604	432,980	431,355	429,730	428,106	426,481	424,856	423,232	$5,186,008
	b. Debt Component Grossed Up For Taxes (C)		154,607	154,038	153,468	152,899	152,329	151,760	151,190	150,621	150,052	149,482	148,913	148,343	1,817,702
8.	Investment Expenses														
	a. Depreciation (D)		247,749	247,749	247,749	247,749	247,749	247,749	247,749	247,749	247,749	247,749	247,749	247,749	2,972,988
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		843,459	841,265	839,071	836,877	834,682	832,489	830,294	828,100	825,907	823,712	821,518	819,324	9,976,698
	a. Recoverable Costs Allocated to Energy		843,459	841,265	839,071	836,877	834,682	832,489	830,294	828,100	825,907	823,712	821,518	819,324	9,976,698
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		843,459	841,265	839,071	836,877	834,682	832,489	830,294	828,100	825,907	823,712	821,518	819,324	9,976,698
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$843,459	$841,265	$839,071	$836,877	$834,682	$832,489	$830,294	$828,100	$825,907	$823,712	$821,518	$819,324	$9,976,698

Notes:
(A) Applicable depreciable base for Big Bend; account 311.53 ($21,689,422), 312.53 ($44,228,920), 315.53 ($13,690,954), and 316.53 ($824,683).
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rates are 3.1%, 3.9%, 4.0%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	
3.	Less: Accumulated Depreciation	(11,546,903)	(11,726,871)	(11,906,839)	(12,086,807)	(12,266,775)	(12,446,743)	(12,626,711)	(12,806,679)	(12,986,647)	(13,166,615)	(13,346,583)	(13,526,551)	(13,706,519)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$51,306,130	51,126,162	50,946,194	50,766,226	50,586,258	50,406,290	50,226,322	50,046,354	49,866,386	49,686,418	49,506,450	49,326,482	49,146,514	
6.	Average Net Investment		51,216,146	51,036,178	50,856,210	50,676,242	50,496,274	50,316,306	50,136,338	49,956,370	49,776,402	49,596,434	49,416,466	49,236,498	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		335,863	334,682	333,502	332,322	331,142	329,962	328,782	327,601	326,421	325,241	324,061	322,881	$3,952,460
	b. Debt Component Grossed Up For Taxes (C)		117,720	117,307	116,893	116,479	116,066	115,652	115,238	114,825	114,411	113,997	113,584	113,170	1,385,342
8.	Investment Expenses														
	a. Depreciation (D)		179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	179,968	2,159,616
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		633,551	631,957	630,363	628,769	627,176	625,582	623,988	622,394	620,800	619,206	617,613	616,019	7,497,418
	a. Recoverable Costs Allocated to Energy		633,551	631,957	630,363	628,769	627,176	625,582	623,988	622,394	620,800	619,206	617,613	616,019	7,497,418
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		633,551	631,957	630,363	628,769	627,176	625,582	623,988	622,394	620,800	619,206	617,613	616,019	7,497,418
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$633,551	$631,957	$630,363	$628,769	$627,176	$625,582	$623,988	$622,394	$620,800	$619,206	$617,613	$616,019	$7,497,418

Notes:
(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($34,665,822), 315.54 ($10,642,027), and 316.54 ($687,934).
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 2.4%, 3.8%, 3.9%, and 3.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	$24,894,395	
3.	Less: Accumulated Depreciation	($1,527,733)	(1,580,204)	(1,632,675)	(1,685,146)	(1,737,617)	(1,790,088)	(1,842,559)	(1,895,030)	(1,947,501)	(1,999,972)	(2,052,443)	(2,104,914)	(2,157,385)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$23,366,662	23,314,191	23,261,720	23,209,249	23,156,778	23,104,307	23,051,836	22,999,365	22,946,894	22,894,423	22,841,952	22,789,481	22,737,010	
6.	Average Net Investment		23,340,426	23,287,955	23,235,484	23,183,013	23,130,542	23,078,071	23,025,600	22,973,129	22,920,658	22,868,187	22,815,716	22,763,245	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		153,061	152,717	152,372	152,028	151,684	151,340	150,996	150,652	150,308	149,964	149,620	149,276	$1,814,018
	b. Debt Component Grossed Up For Taxes (C)		53,648	53,527	53,407	53,286	53,166	53,045	52,924	52,804	52,683	52,563	52,442	52,321	635,816
8.	Investment Expenses														
	a. Depreciation (D)		52,471	52,471	52,471	52,471	52,471	52,471	52,471	52,471	52,471	52,471	52,471	52,471	629,652
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		259,180	258,715	258,250	257,785	257,321	256,856	256,391	255,927	255,462	254,998	254,533	254,068	3,079,486
	a. Recoverable Costs Allocated to Energy		259,180	258,715	258,250	257,785	257,321	256,856	256,391	255,927	255,462	254,998	254,533	254,068	3,079,486
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		259,180	258,715	258,250	257,785	257,321	256,856	256,391	255,927	255,462	254,998	254,533	254,068	3,079,486
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$259,180	$258,715	$258,250	$257,785	$257,321	$256,856	$256,391	$255,927	$255,462	$254,998	$254,533	$254,068	$3,079,486

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($23,438,186)
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.7582% x 1/12.
(D) Applicable depreciation rate is 3.0% and 2.5%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	
3.	Less: Accumulated Depreciation	(135,684)	(139,289)	(142,894)	(146,499)	(150,104)	(153,709)	(157,314)	(160,919)	(164,524)	(168,129)	(171,734)	(175,339)	(178,944)	
4.	CWIP - Non-Interest Bearing	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	74,758	
5.	Net Investment (Lines 2 + 3 + 4)	$1,108,127	1,104,522	1,100,917	1,097,312	1,093,707	1,090,102	1,086,497	1,082,892	1,079,287	1,075,682	1,072,077	1,068,472	1,064,867	
6.	Average Net Investment		1,106,325	1,102,720	1,099,115	1,095,510	1,091,905	1,088,300	1,084,695	1,081,090	1,077,485	1,073,880	1,070,275	1,066,670	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		7,255	7,231	7,208	7,184	7,160	7,137	7,113	7,090	7,066	7,042	7,019	6,995	$85,500
	b. Debt Component Grossed Up For Taxes (C)		2,543	2,535	2,526	2,518	2,510	2,501	2,493	2,485	2,477	2,468	2,460	2,452	29,968
8.	Investment Expenses														
	a. Depreciation (D)		3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	43,260
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		13,403	13,371	13,339	13,307	13,275	13,243	13,211	13,180	13,148	13,115	13,084	13,052	158,728
	a. Recoverable Costs Allocated to Energy		13,403	13,371	13,339	13,307	13,275	13,243	13,211	13,180	13,148	13,115	13,084	13,052	158,728
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		13,403	13,371	13,339	13,307	13,275	13,243	13,211	13,180	13,148	13,115	13,084	13,052	158,728
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,403	$13,371	$13,339	$13,307	$13,275	$13,243	$13,211	$13,180	$13,148	$13,115	$13,084	$13,052	$158,728

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 345.81, and 315.40 ($1,169,053)
(B) Line 6 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 4.0%, 3.5%, 3.0%, 3.3% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. 0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. FERC 158.2 Allowences Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(37,356)	(37,261)	(37,191)	(37,119)	(37,053)	(36,968)	(36,873)	(36,775)	(36,677)	(36,584)	(36,497)	(36,419)	(36,337)	
3.	Total Working Capital Balance	($37,356)	(37,261)	(37,191)	(37,119)	(37,053)	(36,968)	(36,873)	(36,775)	(36,677)	(36,584)	(36,497)	(36,419)	(36,337)	
4.	Average Net Working Capital Balance		($37,309)	($37,226)	($37,155)	($37,086)	($37,011)	($36,921)	($36,824)	($36,726)	($36,631)	($36,541)	($36,458)	($36,378)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(245)	(244)	(244)	(243)	(243)	(242)	(241)	(241)	(240)	(240)	(239)	(239)	(2,901)
	b. Debt Component Grossed Up For Taxes (B)		(86)	(86)	(85)	(85)	(85)	(85)	(85)	(84)	(84)	(84)	(84)	(84)	(1,017)
6.	Total Return Component		(331)	(330)	(329)	(328)	(328)	(327)	(326)	(325)	(324)	(324)	(323)	(323)	(3,918)
7.	Expenses:														
	a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		1,905	1,930	1,928	1,934	1,915	1,905	1,902	1,901	1,908	1,912	1,922	1,918	22,980
8.	Net Expenses (D)		1,905	1,930	1,928	1,934	1,915	1,905	1,902	1,901	1,908	1,912	1,922	1,918	22,980
9.	Total System Recoverable Expenses (Lines 6 + 8)		1,574	1,600	1,599	1,606	1,587	1,578	1,576	1,576	1,584	1,588	1,599	1,595	19,062
	a. Recoverable Costs Allocated to Energy		1,574	1,600	1,599	1,606	1,587	1,578	1,576	1,576	1,584	1,588	1,599	1,595	19,062
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional 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	
11.	Demand Jurisdictional 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	
12.	Retail Energy-Related Recoverable Costs (E)		1,574	1,600	1,599	1,606	1,587	1,578	1,576	1,576	1,584	1,588	1,599	1,595	19,062
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		$1,574	$1,600	$1,599	$1,606	$1,587	$1,578	$1,576	$1,576	$1,584	$1,588	$1,599	$1,595	$19,062

Notes:
(A) Line 4 x 7.8693% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(B) Line 4 x 2.7582% x 1/12.
(C) Line 6 is reported on Schedule 3P
(D) Line 8 is reported on Schedule2P
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 Flue Gas Desulfurization Integration

Project Description:

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012, is $735,696 compared to the original projection of $768,402 representing an insignificant variance.

The actual/estimated O&M expense for the period January 2012 through December 2012 is $4,562,661 compared to the original projection of $4,490,200 resulting in an insignificant variance.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013, is expected to be $1,123,304.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $5,526,100.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Units 1 & 2 Flue Gas Conditioning

Project Description:

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where SO_2 is converted to SO_3. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $415,503 compared to the original projection of $384,629 representing an a variance of 8 percent due to updating depreciation rates consistent with Order No.: PSC-12-0175-PAA-EI.

The actual/estimated O&M expense for this project for the period January 2012 through December 2012 is $0 and did not vary from the original projection.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $375,431.

There are no estimated O&M costs for the period January 2013 through December 2013.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 Continuous Emissions Monitors

Project Description:

Continuous emissions monitors (CEMs) were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting SO_2, NO_x and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

Project Accomplishment:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $83,239 compared to the original projection of $74,263 representing a variance of 12.1 percent due to updating depreciation rates consistent with Order No.: PSC-12-0175-PAA-EI.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $75,414.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $132,352 compared to the original projection of $123,674 representing an insignificant variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $119,754.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 2 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $95,423 compared to the original projection of $89,861 representing an insignificant variance.

Progress Summary: The project was placed in-service May 1998.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $86,368.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II is required by January 1, 2000. The CAAA impose SO_2 emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

In Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999, the Commission found that the FGD project was the most cost-effective alternative for compliance with the SO_2 requirements of Phase II of the CAAA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $8,843,462 compared to the original projection of $8,815,500 representing an insignificant variance.

The actual/estimated O&M expense for the period January 2012 through December 2012 is $17,606,161 as compared to the original estimate of $8,835,100 representing a variance of 99.3 percent. This variance is driven by landfilling approximately 350,000 tons of lesser quality gypsum to be used as valley fill in two landfills.

Progress Summary: The project was placed in-service in December 1999.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is expected to be $8,128,926.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $11,080,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants to the EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance or emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform specialized mercury testing of the inlet and outlet of the last emission control device installed for Big Bend Units 1, 2 or 3, and Polk Unit 1 as part of the mercury data collection. Part of the cost incurred to perform the stack testing is due to the need to construct special test facilities at the Big Bend stack testing location to meet EPA's testing requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012, is $13,770 compared to the original projection of $12,739 representing an insignificant variance.

Progress Summary: The project was placed in-service in December.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is expected to be $12,493.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to optimize the SO_2 removal efficiency and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric performed activities in three key areas to improve the performance and reliability of the Big Bend Units 1, 2 and 3 FGD systems. The majority of the improvements required on the Unit 3 tower module included the tower piping, nozzle and internal improvements, ductwork improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability, absorber system improvements, quencher system improvements, and tower demister improvements. Big Bend Units 1 and 2 FGD system improvements included additional preventative maintenance, oxidation air control improvements, and tower water, air reagent and start-up piping upgrades. In order to ensure reliability of the FGD systems, improvements to the common limestone supply, gypsum de-watering stack reliability and wastewater treatment plant were also being performed.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $2,400,129 compared to the original projection of $2,359,083 representing an insignificant variance.

Progress Summary: The project was placed in-service in January 2002.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is expected to be $2,179,242.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to develop a Best Operational Practices ("BOP") study to minimize emissions from each electrostatic precipitator ("ESP") at Big Bend, as well as perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP. The company is also required to install and operate particulate matter continuous emission monitors on Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric has identified improvements that are necessary to optimize ESP performance such as modifications to the turning vanes and precipitator distribution plates, and upgrades to the controls and software system of the precipitators. Tampa Electric has incurred costs associated with the recommendations of the BOP study and the BACT analysis in 2001 and will continue to experience O&M and capital expenditures during 2002 and beyond.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $1,101,472 as compared to the original projection of $1,076,352 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2012 through December 2012 is $395,718 as compared to the original projection of $390,400 resulting in an insignificant variance.

Progress Summary: This project was placed in-service July 2005.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is expected to be $1,947,674.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $390,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend NO_x Emissions Reduction

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to spend up to $3 million with the goal to reduce NO_x emissions at Big Bend Station. The Consent Decree requires that by December 31, 2002, the company must achieve at least a 30 percent reduction beyond 1998 levels for Big Bend Units 1 and 2 and at least a 15 percent reduction in NO_x emissions from Big Bend Unit 3. Tampa Electric has identified projects that are the first steps to decrease NO_x emissions in these units such as burner and windbox modifications and the installation of a neural network system on each of the Big Bend units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $790,395 as compared to the original projection of $769,550 representing an insignificant variance.

The actual/estimated O&M expense the period January 2012 through December 2012 is $380,422 as compared to the original projection of $395,000 resulting in an insignificant variance.

Progress Summary: The project was placed in-service January 2006.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is expected to be $718,705.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $375,000.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Fuel Oil Tank No. 1 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 1 Upgrade is a 500,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $53,818 compared to the original projection of $50,065 representing an insignificant variance.

Progress Summary: The project was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $48,777.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Fuel Oil Tank No. 2 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 2 Upgrade is a 4,200,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $88,515 compared to the original projection of $82,344 representing an insignificant variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $80,227.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: SO_2 Emission Allowances

Project Description:

The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide emissions by electric utilities. The CAAA requires reductions in SO_2 emissions in two phases. Phase I began on January 1, 1995 and applies to 110 mostly coal-fired utility plants containing about 260 generating units. These plants are owned by some 40 jurisdictional utility systems that are expected to reduce annual SO_2 emissions by as much as 4.5 million tons. Phase II began on January 1, 2000, and applies to virtually all existing steam-electric generating utility units with capacity exceeding 25 megawatts and to new generating utility units of any size. The EPA issues to the owners of generating units allowances (defined as an authorization to emit, during or after a specified calendar year, one ton of SO_2) equal to the number of tons of SO_2 emissions authorized by the CAAA. EPA does not assess a charge for the allowances it awards.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated return on average net working capital for the period January 2012 through December 2012 is ($4,419) compared to the original projection of ($4,391) representing an insignificant variance.

The actual/estimated O&M for the period January 2012 through December 2012 is $9,959 compared to the original projection of $22,262 representing a variance of 55.3 percent. The variance is driven by less cogeneration purchases than expected and the application of a lower rate than originally projected.

Progress Summary: SO_2 emission allowances are being used by Tampa Electric to meet compliance standards for Phase I of the CAAA.

Project Projections: Estimated return on average net working capital for the period January 2013 through December 2013 is projected to be ($3,918).

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $22,980.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees

Project Description:

Chapter 62-4.052, Florida Administrative Code ("F. A. C."), implements the annual regulatory program and surveillance fees for wastewater permits. These fees are in addition to the application fees described in Rule 62-4.050, F. A. C. Tampa Electric's Big Bend, Hookers Point, Polk Power and Gannon Stations are affected by this rule.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2012 through December 2012 is $34,500 compared to the original projection of $34,500 representing no variance.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: Estimated O&M costs for the period January 2013 through December 2013 are projected to be $34,500.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Gannon Thermal Discharge Study

Project Description:

This project is a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code, which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric is required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife with in the primary area of study. The project will have two facets: 1) develop the plan of study and identify the thermal plume, and 2) implement the plan of study through appropriate sampling to make the determination if any adverse impacts are occurring.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2012 through December 2012 is $0 compared to the original projection of $20,000, which represents a variance of 100 percent. The variance is due to pending acceptance of Big Bend Plan of Study regarding thermal variances that will have regulatory impact at Bayside Power Station.

Progress Summary: This project was approved by the Commission in Docket No. 010593-EI on September 4, 2001.

Projections: There are no estimated O&M costs projected for the period of January 2013 through December 2013.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Polk NO_x Emissions Reduction

Project Description:

This project is designed to meet a lower NO_x emissions limit established by the FDEP for Polk Unit 1 by July 1, 2005. The lower limit of 15 parts per million by volume dry basis at 15 percent O_2 is specified in FDEP Permit No. PSD-FL-194F issued February 5, 2002. The project will consist of two phases: 1) the humidification of syngas through the installation of a syngas saturator; and 2) the modification of controls and the installation of additional guide vanes to the diluent nitrogen compressor.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $183,237 as compared to the original projection of $183,237 representing no variance.

The actual/estimated O&M for the period January 2012 through December 2012 is $16,336 compared to the original projection of $35,000, which represents a variance of 53.3 percent. The variance is due forced outages at the Polk Power Station in addition to reduction in water costs and maintenance associated with the saturator that is used to reduce NO_x emissions.

Progress Summary: The project was placed in-service January 2005.

Project Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $166,164.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $28,500.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Bayside SCR Consumables

Project Description:

This project is necessary to achieve the NO_x emissions limit of 3.5 parts per million established by the FDEP Consent Final Judgment and the EPA Consent Decree for the natural gas-fired Bayside Power Station. To achieve this NO_x limit, the installation of selective catalytic reduction (SCR) systems is required. An SCR system requires consumable goods – primarily anhydrous ammonia – to be injected into the catalyst bed in order to achieve the required NO_x emissions limit. Principally, the project is designed to capture the cost of consumable goods necessary to operate the SCR systems.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2012 through December 2012 is $121,844 compared to the original projection of $106,400 resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. As an O&M project, expenses are ongoing annually.

Projections: Estimated O&M costs for the period January 2013 through December 2013 are projected to be $106,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 Separated Overfire Air ("SOFA")

Project Description:

This project is necessary to assist in achieving the NO_x emissions limit established by the FDEP Consent Final Judgment and the EPA Consent Decree for Big Bend Unit 4. A SOFA system stages secondary combustion air to prevent NO_x formation that would otherwise require removal by post-combustion technology. In-furnace combustion control through a SOFA system is the most cost-effective means to reduce NO_x emissions prior to the application of these technologies. Costs associated with the SOFA system will entail capital expenditures for equipment installation and subsequent annual maintenance.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $318,119 compared to the original projection of $303,655 representing an insignificant variance.

The actual/estimated O&M for the period January 2012 through December 2012 is $0 compared to the original projection of $0 representing no variance.

Progress Summary: The project was placed in-service November 2004.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $288,755.

There are no estimated O&M costs for the period January 2013 through December 2013.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 1 Pre-SCR technologies include a neural network system, secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $222,824 compared to the original projection of $211,950 representing an insignificant variance.

The actual/estimated O&M for the period January 2012 through December 2012 is $0 compared to the original projection of $0 representing no variance.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $202,030.

There are no estimated O&M costs for the period January 2013 through December 2013.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 2 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 2 Pre-SCR technologies include secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $211,090 compared to the original projection of $202,159 representing an insignificant variance.

The actual/estimated O&M for the period January 2012 through December 2012 is $0 compared to the original projection of $0 representing no variance.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $191,463.

There are no estimated O&M costs for the period January 2013 through December 2013.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 3 Pre-SCR technologies include a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $374,972 compared to the original projection of $350,697, resulting in a variance of 6.9 percent due to updating depreciation rates consistent with Order No.: PSC-12-0175-PAA-EI.

The actual/estimated O&M for the period January 2012 through December 2012 is $0 compared to the original projection of $0 resulting in no variance.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $340,269.

There are no estimated O&M costs for the period January 2013 through December 2013.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Clean Water Act Section 316(b) Phase II Study

Project Description:

This project is a direct requirement from the EPA to reduce impingement and entrainment of aquatic organisms related to the withdrawal of waters for cooling purposes through cooling water intake structures. The Phase II Rule requires that power plants meeting certain criteria to comply with national performance standards for impingement and entrainment. Accordingly, Tampa Electric must develop its compliance strategies for its H. L. Culbreath Bayside Power and the Big Bend Power Stations and then submit these strategies for approval through a Comprehensive Demonstration Study to the FDEP.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2012 through December 2012 is $56,140 compared to the original projection of $30,000 resulting in a variance of 87.1 percent. This variance is due to an extension of the comment period and postponing of the final rule. The extension created the need for additional outside services in preparation for EPA's rendering the final rule.

Progress Summary: This project was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005.

Projections: Estimated O&M costs for the period January 2013 through December 2013 are projected to be $72,500.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 1 and is scheduled to go in-service April 2010.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $12,544,301 compared to the original projection of $11,474,749 resulting in a variance of 9.3 percent. This variance is due to updating of depreciation rates consistent with Order No. PSC-12-0175-PAA-EI.

The actual/estimated O&M for the period January 2012 through December 2012 is $2,300,371 compared to the original projection of $2,466,489 resulting in a variance due to a decrease in generation caused by extended outages; thereby creating a lower consumption of ammonia that originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $11,342,083.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $2,259,818.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 2 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 2 and is scheduled to go in-service September 2009.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $13,355,306 compared to the original projection of $12,505,318, resulting in a variance of 6.8 percent. This variance is due to updating of depreciation rates consistent with Order No. PSC-12-0175-PAA-EI.

The actual/estimated O&M for the period January 2012 through December 2012 is $2,328,275 compared to the original projection of $2,536,432 representing a variance of 8.2 percent due to the consumption of ammonia utilized in the SO_3 mitigation system being less than projected. The ammonia is utilized in the SO_3 mitigation system to meet ongoing regulation requirements.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $12,121,742.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $2,506,409.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 3 and is scheduled to go in-service July 2008.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $11,105,329 compared to the original projection of $10,258,438 resulting in a variance of 8.3 percent. This variance is due to updating of depreciation rates consistent with Order No. PSC-12-0175-PAA-EI.

The actual/estimated O&M for the period January 2012 through December 2012 is $1,868,922 compared to the original projection of $1,513,033 resulting in a variance of 23.5 percent. This variance is due to consumption in ammonia for the SO_3 mitigation system being greater than projected. The ammonia is utilized in the SO_3 mitigation system to meet ongoing regulation requirements.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $9,976,698.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $1,548,628.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 4 and is scheduled to go in-service May 2007.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $8,363,075 compared to the original projection of $7,799,065 resulting in a variance of 7.2 percent. This variance is due to updating of depreciation rates consistent with Order No. PSC-12-0175-PAA-EI.

The actual/estimated O&M for the period January 2012 through December 2012 is $868,068 compared to the original projection of $998,269 representing a variance of 13 percent. The variance is due to a credit for equipment that offset an increase in ammonia consumption for SO_3 mitigation system.

Progress Summary: This project was placed in-service in May 2007.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $7,497,418.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $1,041,076.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Arsenic Groundwater Standard Program

Project Description:
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2012 through December 2012 is $84,499 compared to the original projection of $667,000 resulting in a variance of 87.3 percent. The variance is due to FDEP delay in approval of activity associated with projected work.

Progress Summary: In Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006, the Commission granted Tampa Electric cost recovery approval for prudent costs associated with this project.

Projections: Estimated O&M costs for the period January 2013 through December 2013 are projected to be $667,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Flue Gas Desulfurization ("FGD") System Reliability

Project Description:
The Big Bend FGD Reliability project is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. The compliance dates for the strictest operational characteristics are January 1, 2011 for Big Bend Unit 3 and January 1, 2013 for Big Bend Units 1 and 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $2,977,349 compared to the original projection of $3,473,539 resulting in variance of 14.3 percent. This variance is due to overall expenditures for the project now estimated to be less and an extension of its in-service date from January 2012 to July 2012.

Progress Summary: In Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006, the Commission granted cost recovery approval for prudent costs associated with this project.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $3,079,486.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Clean Air Mercury Rule ("CAMR")

Project Description:
The EPA established standards of performance for mercury for new and existing coal-fired electric utility steam generating units as defined in the federal Clean Air Act, known as the Clean Air Mercury Rule ("CAMR"). CAMR was designed to permanently cap mercury emissions nation-wide in two phases ending in 2018. On February 8, 2008 the Washington, D.C. Circuit Court vacated EPA's rule removing power plants from the Clean Air Act list of regulated sources of hazardous air pollutants under section 112 and vacated the Clean Air Mercury Rule. However, on May 3, 2011 EPA published a new proposed rule for mercury and other hazardous air pollutants according to the National Emissions Standards for Hazardous Air Pollutants section of the Clean Air Act. The proposed rule calls for mercury monitoring requirements comparable to CAMR by 2014. Tampa Electric must conduct extensive emissions testing and engineering studies at Big Bend Station and Polk Power Station to determine what actions are required to meet the proposed standards.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $174,891 compared to the original projection of $166,916 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2012 through December 2012 is $25,401 compared to the original projection of $24,000 resulting in an insignificant variance.

Progress Summary: In Docket No. 060583-EI, Order No.: PSC-06-0926-PAA-EI, issued November 6, 2006, the Commission granted cost recovery approval for prudent costs associated with this project.

Projections: Estimated depreciation plus return for the period January 2013 through December 2013 is projected to be $158,728.

Estimated O&M costs for the period January 2013 through December 2013 are projected to be $20,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Greenhouse Gas Reduction Program

Project Description:
On September 22, 2009, the EPA enacted a new rule for reporting Greenhouse Gas ("GHG") emissions from large sources and suppliers effective January 1, 2010 in preparation for the first annual GHG report, due March 31, 2011. The new rule is intended to collect accurate and timely emissions data to inform future policy decisions as set forth in the final rule for GHG emission reporting pursuant to the Florida Climate Protection Act, Chapter 403.44 of the Florida Statutes and the docket EPA-HQ-OAR2008-0508-054. The nationwide GHG emissions reduction rule will impact Tampa Electric's generation fleet, components of its transmission and distribution system as well as company service vehicles. According to the rule, the company must begin collecting greenhouse gas emissions data effective January 1, 2010 to establish a baseline inventory to report to the EPA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2012 through December 2012 is $90,788 compared to the original projection of $40,000 resulting in a variance of 127 percent. The variance is due the cost of the Enviance subscription being higher than originally projected.

Progress Summary: Cost recovery was approved in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010.

Projections: Estimated O&M costs for the period January 2013 through December 2013 are projected to be $90,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Phillips Oil Tank No. 1 Upgrade

Project Description:

The Phillips Oil Tank No. 1 Upgrade is a 1,300,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing a spill containment for piping fittings and valves surrounding the tank, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $31,318 compared to the original projection of $5,267 representing a variance of 494.6 percent. This variance is due to retirement of this asset and the resulting recovery of net investment.

Progress Summary: The project is to be retired December 2012.

Projections: See Project Summary above.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2013 through December 2013
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Phillips Oil Tank No. 4 Upgrade

Project Description:

The Phillips Oil Tank No. 4 Upgrade is a 57,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing a spill containment for piping fittings and valves surrounding the tank, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2012 through December 2012 is $49,049 compared to the original projection of $8,267 representing a variance of 493.3 percent. This variance is due to retirement of this asset and the resulting recovery of net investment.

Progress Summary: The project is to be retired December 2012.

Projections: See Project Summary above.

Form 42 - 6P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2013 to December 2013

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Projected Sales at Meter (MWh)	(3) Effective Sales at Secondary Level (MWh)	(4) Projected Avg 12 CP at Meter (MW)	(5) Demand Loss Expansion Factor	(6) Energy Loss Expansion Factor	(7) Projected Sales at Generation (MWh)	(8) Projected Avg 12 CP at Generation (MW)	(9) Percentage of MWh Sales at Generation (%)	(10) Percentage of 12 CP Demand at Generation (%)	(11) 12 CP & 25% Allocation Factor (%)
RS	51.79%	8,476,092	8,476,092	1,868	1.08103	1.05698	8,959,031	2,019	46.72%	56.21%	53.84%
GS, TS	57.57%	1,014,602	1,014,602	201	1.08103	1.05696	1,072,394	217	5.59%	6.04%	5.93%
GSD, SBF	75.72%	7,632,062	7,619,584	1,151	1.07653	1.05315	8,037,724	1,239	41.91%	34.49%	36.35%
IS	89.14%	861,507	846,603	110	1.03199	1.01859	877,522	114	4.58%	3.17%	3.52%
LS1	935.37%	217,753	217,753	3	1.08103	1.05698	230,160	3	1.20%	0.08%	0.36%
TOTAL *		18,202,016	18,174,634	3,333			19,176,831	3,592	100.00%	100.00%	100.00%

Notes:
(1) Average 12 CP load factor based on 2012 Projected calendar data
(2) Projected MWh sales for the period January 2013 to December 2013
(3) Effective sales at secondary level for the period January 2013 to December 2013.
(4) Column 2 / (Column 1 x 8760)
(5) Based on 2012 projected demand losses.
(6) Based on 2012 projected energy losses.
(7) Column 2 x Column 6
(8) Column 4 x Column 5
(9) Column 7 / Total Column 7
(10) Column 8 / Total Column 8
(11) Column 9 x 0.25 + Column 10 x 0.75

* Totals on this schedule may not foot due to rounding

DOCKET NO. 120007-EI
ECRC 2013 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 6

Form 42 - 7P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2013 to December 2013

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 25% Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (MWh)	(7) Effective Sales at Secondary Level (MWh)	**(8) Environmental Cost Recovery Factors (¢/kWh)**
RS	46.72%	53.84%	46,773,423	520,661	47,294,084	8,476,092	8,476,092	**0.558**
GS, TS	5.59%	5.93%	5,598,768	57,330	5,656,098	1,014,602	1,014,602	**0.557**
GSD, SBF	41.91%	36.35%	41,963,452	351,504	42,314,956	7,632,062	7,619,584	
Secondary								**0.555**
Primary								**0.550**
Transmission								**0.544**
IS	4.58%	3.52%	4,581,378	34,057	4,615,435	861,507	846,603	
Secondary								**0.545**
Primary								**0.540**
Transmission								**0.534**
LS1	1.20%	0.36%	1,201,622	3,482	1,205,104	217,753	217,753	**0.553**
TOTAL *	100.00%	100.00%	100,118,644	967,107	101,085,751	18,202,016	18,174,634	**0.556**

* Totals on this schedule may not foot due to rounding

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 11
(3) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) From Form 42-6P, Column 2
(7) From Form 42-6P, Column 3
(8) Column 5 / Column 7 x 10

DOCKET NO. 120007-EI
ECRC 2013 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 7

Form 42 - 8P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 to December 2013

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base Per Actual May 2012 Capital Structure ($000)	(2) Ratio	(3) Cost Rate	(4) Weighted Cost Rate
		%	%	%
Long Term Debt	$ 1,488,583	39.08%	6.59%	2.5754%
Short Term Debt	9,122	0.24%	0.64%	0.0015%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	105,073	2.76%	6.21%	0.1714%
Common Equity	1,633,530	42.87%	11.25%	4.8229%
Deferred ITC - Weighted Cost	8,810	0.23%	9.00%	0.0207%
Accumulated Deferred Income Taxes	564,424	14.82%	0.00%	0.0000%
Zero Cost ITCs				
Total	$ 3,809,542	100.00%		7.5919%

ITC split between Debt and Equity:

Long Term Debt	$ 1,488,583	Long Term Debt	47.54%	
Short Term Debt	9,122	Short Term Debt	0.29%	47.83%
Equity - Preferred	0	Equity - Preferred	0.00%	
Equity - Common	1,633,530	Equity - Common	52.17%	52.170%
Total	$ 3,131,235	Total	100.00%	

Deferred ITC - Weighted Cost:

Debt = .0207% * 47.83%	0.0099%
Equity = .0207% * 52.17%	0.0108%
Weighted Cost	0.0207%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.8229%
Deferred ITC - Weighted Cost	0.0108%
	4.8337%
Times Tax Multiplier	1.628002
Total Equity Component	7.8693%

Total Debt Cost Rate:

Long Term Debt	2.5754%
Short Term Debt	0.0015%
Customer Deposits	0.1714%
Deferred ITC - Weighted Cost	0.0099%
Total Debt Component	2.7582%

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)

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Line		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2011 - December 2011 (Schedule 2A, Line 5 + 6 + 9)	9,104,881
2	Estimated/Actual True-Up Amount approved for the period January 2011 - December 2011 (FPSC Order No. PSC-11-0553-FOF-EI)	14,380,513
3	Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2013 - December 2013 (Lines 1 + 2)	(5,275,632)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 35
PARTY Gulf Power Company
DESCRIPTION R.W. Dodd (RWD-1), Calculation of Final
DATE True-up 1/11-12/11

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	12,003,577	10,570,628	9,823,237	11,264,837	12,276,522	15,594,951	15,802,812	16,136,141	12,403,879	10,307,489	9,756,787	9,999,700	145,940,561
2	True-Up Provision (Order No. PSC-10-0683-FOF-EI)	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	9,510,009
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	12,796,077	11,363,129	10,615,738	12,057,338	13,069,023	16,387,451	16,595,313	16,928,642	13,196,380	11,099,990	10,549,288	10,792,201	155,450,570
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	1,198,954	2,139,055	1,446,487	1,610,954	1,651,024	2,269,513	2,437,699	2,031,789	2,029,680	1,389,725	2,345,498	2,576,143	23,126,521
	b Capital Investment Projects (Schedule 7E, Line 9)	10,292,615	10,324,148	10,304,039	10,306,525	10,242,621	10,241,708	10,258,416	10,292,606	10,282,483	10,258,144	10,231,729	10,201,040	123,236,074
	c **Total Jurisdictional ECRC Costs**	11,491,569	12,463,203	11,750,526	11,917,479	11,893,645	12,511,221	12,696,115	12,324,395	12,312,163	11,647,869	12,577,227	12,777,183	146,362,595
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	1,304,508	(1,100,074)	(1,134,788)	139,859	1,175,378	3,876,230	3,899,198	4,604,247	884,217	(547,879)	(2,027,939)	(1,984,982)	9,087,975
6	Interest Provision (Schedule 3E, Line 10)	2,210	2,067	1,510	1,099	965	1,110	1,338	1,430	1,197	1,152	1,302	659	16,039
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2010	626,546	1,140,764	(749,744)	(2,675,522)	(3,327,065)	(2,943,223)	141,617	3,249,652	7,062,828	7,156,608	5,817,380	2,998,242	626,546
	b Final True-Up from January 2009 - December 2009 (Order No. PSC-10-0683-FOF-EI)	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785
8	True-Up Collected/(Refunded) (see Line 2)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(9,510,009)
	Annual NOx Allowance Expense													
9	Adjustments									867				867
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	10,885,549	8,995,041	7,069,263	6,417,720	6,801,563	9,886,402	12,994,437	16,807,613	16,901,393	15,562,165	12,743,027	9,966,203	9,966,203

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Beg. True-Up Amount (Schedule 2E, Lines 7a + 7b)	10,371,331	10,885,549	8,995,041	7,069,263	6,417,720	6,801,563	9,886,402	12,994,437	16,807,613	16,901,393	15,562,165	12,743,027	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	10,883,339	8,992,974	7,067,753	6,416,621	6,800,598	9,885,292	12,993,099	16,806,183	16,899,329	15,561,013	12,741,725	9,965,544	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	21,254,670	19,878,523	16,062,794	13,485,884	13,218,318	16,686,855	22,879,501	29,800,620	33,706,942	32,462,407	28,303,891	22,708,572	
4	Average True-Up Amount (Line 3 x 1/2)	10,627,335	9,939,262	8,031,397	6,742,942	6,609,159	8,343,427	11,439,751	14,900,310	16,853,471	16,231,203	14,151,945	11,354,286	
5	Interest Rate (First Day of Reporting Business Month)	0.002500	0.002500	0.002500	0.002000	0.001900	0.001600	0.001600	0.001200	0.001100	0.000600	0.001100	0.001100	
6	Interest Rate (First Day of Subsequent Business Month)	0.002500	0.002500	0.002000	0.001900	0.001600	0.001600	0.001200	0.001100	0.000600	0.001100	0.001100	0.000300	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.005000	0.005000	0.004500	0.003900	0.003500	0.003200	0.002800	0.002300	0.001700	0.001700	0.002200	0.001400	
8	Average Interest Rate (Line 7 x 1/2)	0.002500	0.002500	0.002250	0.001950	0.001750	0.001600	0.001400	0.001150	0.000850	0.000850	0.001100	0.000700	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.000208	0.000208	0.000188	0.000163	0.000146	0.000133	0.000117	0.000096	0.000071	0.000071	0.000092	0.000058	
10	Interest Provision for the Month (Line 4 x Line 9)	2,210	2,067	1,510	1,099	965	1,110	1,338	1,430	1,197	1,152	1,302	659	16,039

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Variance Report of O & M Activities
(in Dollars)

Line		(1) Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent
1	Description of O & M Activities				
.1	Sulfur	0	0	0	0.0 %
.2	Air Emission Fees	645,480	769,854	(124,374)	(16.2) %
.3	Title V	231,818	118,191	113,627	96.1 %
.4	Asbestos Fees	1,000	2,200	(1,200)	(54.5) %
.5	Emission Monitoring	578,086	569,277	8,809	1.5 %
.6	General Water Quality	725,837	676,093	49,744	7.4 %
.7	Groundwater Contamination Investigation	1,807,108	1,816,702	(9,594)	(0.5) %
.8	State NPDES Administration	36,208	36,511	(303)	(0.8) %
.9	Lead and Copper Rule	12,222	12,208	14	0.1 %
.10	Env Auditing/Assessment	878	7,014	(6,136)	(87.5) %
.11	General Solid & Hazardous Waste	895,617	767,470	128,147	16.7 %
.12	Above Ground Storage Tanks	74,351	109,803	(35,452)	(32.3) %
.13	Low Nox	0	0	0	0.0 %
.14	Ash Pond Diversion Curtains	1,104	1,104	0	0.0 %
.15	Mercury Emissions	0	0	0	0.0 %
.16	Sodium Injection	42,862	66,564	(23,702)	(35.6) %
.17	Gulf Coast Ozone Study	0	0	0	0.0 %
.18	SPCC Substation Project	0	0	0	0.0 %
.19	FDEP NOx Reduction Agreement	1,882,215	1,937,051	(54,836)	(2.8) %
.20	CAIR/CAMR/CAVR Compliance Program	13,095,805	13,836,032	(740,227)	(5.3) %
.21	MACT ICR	12,270	0	12,270	100.0 %
.22	Crist Water Conservation	6,334	144,944	(138,610)	(95.6) %
.23	Mercury Allowances	0	0	0	0.0 %
.24	Annual NOx Allowances	2,858,610	3,265,584	(406,974)	(12.5) %
.25	Seasonal NOx Allowances	7,706	15,853	(8,147)	(51.4) %
.26	SO2 Allowances	979,560	1,239,073	(259,513)	(20.9) %
2	Total O & M Activities	23,895,071	25,391,528	(1,496,457)	(5.9) %
3	Recoverable Costs Allocated to Energy	20,335,516	21,818,583	(1,483,067)	(6.8) %
4	Recoverable Costs Allocated to Demand	3,559,555	3,572,945	(13,390)	(0.4) %

Notes:

Column (1) is the End of Period Totals on Schedule 5E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-10-0683-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

O & M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
	.1 Sulfur	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.2 Air Emission Fees	-	645,480	-	-	-	-	-	-	-	-	-	-	645,480	0	645,480
	.3 Title V	8,437	7,797	8,446	8,607	10,395	7,995	9,013	9,628	133,421	8,739	8,503	10,837	231,818	0	231,818
	.4 Asbestos Fees	-	1,000	-	-	-	-	-	-	-	-	-	-	1,000	1,000	0
	.5 Emission Monitoring	37,033	38,531	40,031	38,769	34,105	66,863	49,082	65,405	40,451	47,149	74,560	46,107	578,086	0	578,086
	.6 General Water Quality	32,837	22,795	40,146	47,941	68,620	54,229	183,755	69,720	63,411	63,698	47,235	31,450	725,837	725,837	0
	.7 Groundwater Contamination Investigation	56,636	108,985	79,477	90,047	188,537	260,444	164,347	121,305	101,522	61,952	597,747	(23,891)	1,807,108	1,807,108	0
	.8 State NPDES Administration	-	-	-	555	1,456	40,054	(23,131)	1,532	(19,743)	985	-	34,500	36,208	36,208	0
	.9 Lead and Copper Rule	325	-	-	3,883	-	-	3,988	-	-	4,026	-	-	12,222	12,222	0
	.10 Env Auditing/Assessment	14	-	-	-	-	-	-	-	-	-	535	329	878	878	0
	.11 General Solid & Hazardous Waste	139,352	46,936	196,641	119,360	(47,476)	48,802	52,201	72,326	72,330	83,302	81,426	30,417	895,617	895,617	0
	.12 Above Ground Storage Tanks	14,896	29,680	(25,083)	18,284	7,819	2,322	1,689	2,945	4,746	2,025	15,449	(421)	74,351	74,351	0
	.13 Low NOx	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	1,104	-	-	-	-	-	-	-	-	-	-	-	1,104	0	1,104
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	-	7,614	-	7,794	9,182	8,374	1,070	-	-	-	8,828	-	42,862	0	42,862
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.19 FDEP NOx Reduction Agreement	186,059	233,378	122,619	111,846	109,076	261,140	183,624	173,245	103,959	155,576	160,758	80,935	1,882,215	0	1,882,215
	.20 CAIR/CAMR/CAVR Compliance Program	212,902	843,643	824,707	972,804	900,561	1,129,062	1,385,291	1,081,895	1,387,091	874,295	1,323,466	2,160,088	13,095,805	0	13,095,805
	.21 MACT ICR	-	-	-	-	16,000	12,270	(16,000)	-	-	-	-	-	12,270	0	12,270
	.22 Crist Water Conservation	11,170	309	(5,754)	1,867	(634)	1,986	(1,378)	782	3,937	(668)	2,201	(7,484)	6,334	6,334	0
	.23 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.24 Annual NOx Allowances	465,831	166,384	163,665	164,212	290,031	337,133	356,053	346,976	173,938	127,031	96,285	171,071	2,858,610	0	2,858,610
	.25 Seasonal NOx Allowances	-	-	-	-	724	1,138	1,191	1,216	4,044	(601)	(6)	-	7,706	0	7,706
	.26 SO2 Allowances	78,040	57,435	50,072	74,901	117,095	109,698	162,405	150,031	27,174	8,548	9,708	134,453	979,560	0	979,560
2	Total of O & M Activities	1,244,636	2,209,967	1,494,967	1,660,870	1,705,491	2,341,510	2,513,200	2,097,006	2,096,281	1,436,057	2,426,695	2,668,391	23,895,071	3,559,555	20,335,516
3	Recoverable Costs Allocated to Energy	989,406	2,000,261	1,209,541	1,378,933	1,487,169	1,933,673	2,131,729	1,828,396	1,870,078	1,220,737	1,682,102	2,603,491	20,335,516		
4	Recoverable Costs Allocated to Demand	255,230	209,706	285,426	281,937	218,322	407,837	381,471	268,610	226,203	215,320	744,593	64,900	3,559,555		
5	Retail Energy Jurisdictional Factor	0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784			
6	Retail Demand Jurisdictional Factor	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582			
7	Jurisdictional Energy Recoverable Costs (A)	952,796	1,936,803	1,171,206	1,339,037	1,440,461	1,876,171	2,069,786	1,772,726	1,811,516	1,182,059	1,627,369	2,513,550	19,693,480		
8	Jurisdictional Demand Recoverable Costs (B)	246,158	202,252	275,281	271,917	210,563	393,342	367,913	259,063	218,164	207,666	718,129	62,593	3,433,041		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,198,954	2,139,055	1,446,487	1,610,954	1,651,024	2,269,513	2,437,699	2,031,789	2,029,680	1,389,725	2,345,498	2,576,143	23,126,521		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 6A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Variance Report of Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		(1) Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent	
1	Description of Investment Projects					
.1	Air Quality Assurance Testing	68,016	68,016	0	0.0	%
.2	Crist 5, 6 & 7 Precipitator Projects	2,052,905	2,121,013	(68,108)	(3.2)	%
.3	Crist 7 Flue Gas Conditioning	167,953	167,953	0	0.0	%
.4	Low NOx Burners, Crist 6 & 7	1,976,056	1,976,056	0	0.0	%
.5	CEMS - Plnts Crist Scholz, Smith & Daniel	1,410,744	1,413,429	(2,685)	(0.2)	%
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	95,407	98,926	(3,519)	(3.6)	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	26,393	26,393	0	0.0	%
.8	Crist Cooling Tower Cell	58,789	58,789	0	0.0	%
.9	Crist 1-5 Dechlorination	26,474	29,359	(2,885)	(9.8)	%
.10	Crist Diesel Fuel Oil Remediation	6,541	6,541	0	0.0	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	8,589	8,589	0	0.0	%
.12	Crist IWW Sampling System	5,007	5,007	0	0.0	%
.13	Sodium Injection System	47,340	47,340	0	0.0	%
.14	Smith Stormwater Collection System	253,964	253,964	0	0.0	%
.15	Smith Waste Water Treatment Facility	35,975	35,976	(1)	(0.0)	%
.16	Daniel Ash Management Project	2,027,202	2,041,884	(14,682)	(0.7)	%
.17	Smith Water Conservation	16,379	91,379	(75,000)	(82.1)	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	16,919,636	16,920,040	(404)	(0.0)	%
.20	SPCC Compliance	122,102	122,102	0	0.0	%
.21	Crist Common FTIR Monitor	7,589	7,589	0	0.0	%
.22	Precipitator Upgrades for CAM Compliance	3,960,080	3,960,080	0	0.0	%
.23	Plant Groundwater Investigation	0	0	0	0.0	%
.24	Crist Water Conservation	2,768,033	2,772,266	(4,233)	(0.2)	%
.25	Plant NPDES Permit Compliance Projects	778,803	783,276	(4,473)	(0.6)	%
.26	CAIR/CAMR/CAVR Compliance	93,163,916	92,998,925	164,991	0.2	%
.27	General Water Quality	7,873	7,873	0	0.0	%
.28	Mercury Allowances	0	0	0	0.0	%
.29	Annual Nox Allowances	333,095	324,270	8,825	2.7	%
.30	Seasonal Nox Allowances	277	277	0	0.0	%
.31	SO2 Allowances	945,445	938,481	6,964	0.7	%
2	Total Investment Projects - Recoverable Costs	127,290,583	127,285,793	4,790	0.0	%
3	Recoverable Costs Allocated to Energy	121,532,865	121,431,341	101,524	0.1	%
4	Recoverable Costs Allocated to Demand	5,757,718	5,854,452	(96,734)	(1.7)	%

Notes:
Column (1) is the End of Period Totals on Schedule 7E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-10-0683-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 7A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	5,885	5,845	5,806	5,767	5,727	5,688	5,648	5,609	5,569	5,530	5,491	5,451	68,016	0	68,016
	.2 Crist 5, 6 & 7 Precipitator Projects	153,835	158,464	159,806	156,825	156,992	158,008	159,394	172,211	185,446	189,623	195,521	206,780	2,052,905	0	2,052,905
	.3 Crist 7 Flue Gas Conditioning	14,008	14,005	14,003	14,001	13,999	13,997	13,995	13,993	13,991	13,989	13,987	13,985	167,953	0	167,953
	.4 Low NOx Burners, Crist 6 & 7	166,048	165,798	165,548	165,297	165,047	164,797	164,546	164,296	164,045	163,795	163,545	163,294	1,976,056	0	1,976,056
	5 CEMS - Plnts Crist Scholz, Smith & Daniel	118,104	118,145	118,100	118,000	117,806	117,690	117,588	117,365	117,212	117,028	116,839	116,867	1,410,744	0	1,410,744
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	8,038	8,022	8,006	7,990	7,975	7,958	7,942	7,928	7,911	7,895	7,879	7,863	95,407	88,068	7,339
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,235	2,229	2,222	2,216	2,209	2,203	2,196	2,191	2,183	2,176	2,170	2,163	26,393	24,364	2,029
	.8 Crist Cooling Tower Cell	4,907	4,906	4,905	4,903	4,902	4,900	4,898	4,897	4,896	4,893	4,892	4,890	58,789	54,268	4,521
	.9 Crist 1-5 Dechlorination	2,198	2,189	2,181	2,173	2,165	2,156	2,148	2,139	2,131	2,127	2,271	2,596	26,474	24,436	2,038
	.10 Crist Diesel Fuel Oil Remediation	556	554	552	549	548	546	544	542	540	539	536	535	6,541	6,038	503
	.11 Crist Bulk Tanker Unload Sec Contain Struc	731	729	726	722	720	717	715	712	708	706	703	700	8,589	7,929	660
	.12 Crist IWW Sampling System	426	424	423	422	419	418	417	415	413	412	410	408	5,007	4,621	386
	.13 Sodium Injection System	4,003	3,993	3,983	3,971	3,961	3,950	3,940	3,929	3,918	3,908	3,898	3,886	47,340	0	47,340
	.14 Smith Stormwater Collection System	21,561	21,489	21,416	21,344	21,272	21,200	21,128	21,055	20,983	20,911	20,839	20,766	253,964	234,428	19,536
	.15 Smith Waste Water Treatment Facility	3,023	3,019	3,014	3,010	3,004	3,000	2,995	2,991	2,987	2,982	2,977	2,973	35,975	33,207	2,768
	.16 Daniel Ash Management Project	172,058	171,873	171,702	171,288	170,861	170,430	170,045	166,623	166,209	165,785	165,371	164,957	2,027,202	1,871,264	155,938
	.17 Smith Water Conservation	1,385	1,381	1,377	1,373	1,369	1,367	1,363	1,360	1,356	1,353	1,349	1,346	16,379	15,118	1,261
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist FDEP Agreement for Ozone Attainment	1,443,106	1,440,577	1,437,095	1,432,068	1,408,707	1,405,092	1,401,456	1,397,629	1,393,942	1,390,347	1,386,683	1,382,934	16,919,636	0	16,919,636
	.20 SPCC Compliance	10,316	10,290	10,265	10,239	10,213	10,188	10,162	10,137	10,111	10,086	10,060	10,035	122,102	112,706	9,396
	.21 Crist Common FTIR Monitor	642	640	639	636	635	634	631	630	628	626	625	623	7,589	0	7,589
	.22 Precipitator Upgrades for CAM Compliance	334,390	333,593	332,795	332,000	331,203	330,406	329,608	328,811	328,014	327,217	326,420	325,623	3,960,080	0	3,960,080
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	230,141	229,693	229,683	230,093	230,950	231,414	231,210	230,906	230,646	230,498	230,789	232,010	2,768,033	2,555,108	212,925
	.25 Plant NPDES Permit Compliance Projects	65,768	65,606	65,440	65,274	65,109	64,943	64,778	64,612	64,446	64,281	64,243	64,303	778,803	718,895	59,908
	.26 CAIR/CAMR/CAVR Compliance	7,799,526	7,780,004	7,764,772	7,750,112	7,737,455	7,727,272	7,746,350	7,797,220	7,791,917	7,773,883	7,755,864	7,739,541	93,163,916	0	93,163,916
	.27 General Water Quality	684	679	674	669	664	659	653	648	643	638	633	629	7,873	7,268	605
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual NOx Allowances	40,574	37,592	36,035	34,489	32,346	29,387	26,118	22,801	20,345	18,925	17,872	16,611	333,095	0	333,095
	.30 Seasonal NOx Allowances	44	44	44	44	40	31	20	9	1	0	0	0	277	0	277
	.31 SO2 Allowances	83,170	82,531	82,011	81,409	80,503	79,433	78,150	76,676	75,778	75,545	75,459	74,780	945,445	0	945,445
2	Total Investment Projects - Recoverable Costs	10,687,362	10,664,314	10,643,223	10,616,884	10,576,801	10,558,484	10,568,638	10,618,335	10,616,969	10,595,698	10,577,326	10,566,549	127,290,583	5,757,718	121,532,865
3	Recoverable Costs Allocated to Energy	10,203,646	10,181,468	10,160,837	10,134,793	10,094,602	10,076,547	10,087,535	10,140,963	10,140,511	10,120,053	10,101,830	10,090,080	121,532,865		
4	Recoverable Costs Allocated to Demand	483,716	482,846	482,386	482,091	482,199	481,937	481,103	477,372	476,458	475,645	475,496	476,469	5,757,718		
5	Retail Energy Jurisdictional Factor	0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784			
6	Retail Demand Jurisdictional Factor	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582			
7	Jurisdictional Energy Recoverable Costs (B)	9,826,091	9,858,463	9,838,798	9,841,568	9,777,560	9,776,900	9,794,413	9,832,200	9,822,959	9,799,404	9,773,133	9,741,506	117,682,995		
8	Jurisdictional Demand Recoverable Costs (C)	466,524	465,685	465,241	464,957	465,061	464,808	464,803	460,406	459,524	458,740	458,596	459,534	5,553,079		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	10,292,615	10,324,148	10,304,039	10,306,525	10,242,621	10,241,708	10,258,416	10,292,606	10,282,483	10,258,144	10,231,729	10,201,040	123,236,074		

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9, Pages 28-31 of Schedule 8E, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	
3	Less: Accumulated Depreciation (C)	(167,623)	(171,799)	(175,975)	(180,151)	(184,327)	(188,503)	(192,679)	(196,855)	(201,031)	(205,207)	(209,383)	(213,559)	(217,735)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	183,189	179,013	174,837	170,661	166,485	162,309	158,133	153,957	149,781	145,605	141,429	137,253	133,077	
6	Average Net Investment		181,101	176,925	172,749	168,573	164,397	160,221	156,045	151,869	147,693	143,517	139,341	135,165	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,331	1,300	1,269	1,239	1,208	1,178	1,146	1,116	1,085	1,054	1,024	993	13,943
	b Debt Component (Line 6 x Debt Component x 1/12)		378	369	361	352	343	334	326	317	308	300	291	282	3,961
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	50,112
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,885	5,845	5,806	5,767	5,727	5,688	5,648	5,609	5,569	5,530	5,491	5,451	68,016
	a Recoverable Costs Allocated to Energy		5,885	5,845	5,806	5,767	5,727	5,688	5,648	5,609	5,569	5,530	5,491	5,451	68,016
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		5,667	5,660	5,622	5,600	5,547	5,519	5,484	5,438	5,395	5,355	5,312	5,263	65,862
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		5,667	5,660	5,622	5,600	5,547	5,519	5,484	5,438	5,395	5,355	5,312	5,263	65,862

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) PE 1244 7 year amortization; PE 1006 fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		110,440	962,561	(587,124)	47,178	81,149	225,836	151,814	2,646,124	243,940	719,924	601,084	1,846,816	
	b Clearings to Plant		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	
	d Cost of Removal		4,216	5,353	5,163	4,279	3,913	5,927	11,493	9,049	8,049	14,740	16,377	23,825	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	
3	Less: Accumulated Depreciation (C)	(3,477,093)	(3,523,540)	(3,568,850)	(3,614,350)	(3,660,734)	(3,707,484)	(3,752,220)	(3,791,390)	(3,833,004)	(3,875,618)	(3,911,541)	(3,945,827)	(3,972,665)	
4	CWIP - Non Interest Bearing	471,744	582,184	1,544,745	957,621	1,004,799	1,085,948	1,311,784	1,463,598	4,109,722	4,353,662	5,073,586	5,674,670	7,521,486	
5	Net Investment (Lines 2 + 3 + 4)	10,904,180	10,968,173	11,885,424	11,252,800	11,253,594	11,287,993	11,469,093	11,581,737	14,186,247	14,387,573	15,071,574	15,638,372	17,458,350	
6	Average Net Investment		10,936,177	11,426,799	11,569,112	11,253,197	11,270,794	11,378,543	11,525,415	12,883,992	14,286,910	14,729,574	15,354,973	16,548,361	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		80,348	83,953	84,998	82,677	82,807	83,598	84,677	94,659	104,966	108,219	112,812	121,581	1,125,295
	b Debt Component (Line 6 x Debt Component x 1/12)		22,824	23,848	24,145	23,485	23,522	23,747	24,054	26,889	29,817	30,741	32,046	34,536	319,654
8	Investment Expenses														
	a Depreciation (E)		40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	486,888
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	121,068
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		153,835	158,464	159,806	156,825	156,992	158,008	159,394	172,211	185,446	189,623	195,521	206,780	2,052,905
	a Recoverable Costs Allocated to Energy		153,835	158,464	159,806	156,825	156,992	158,008	159,394	172,211	185,446	189,623	195,521	206,780	2,052,905
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		148,143	153,437	154,741	152,289	152,061	153,309	154,762	166,968	179,639	183,615	189,159	199,637	1,987,760
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		148,143	153,437	154,741	152,289	152,061	153,309	154,762	166,968	179,639	183,615	189,159	199,637	1,987,760

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.5% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,462,270	1,462,057	1,461,844	1,461,631	1,461,418	1,461,205	1,460,992	1,460,779	1,460,566	1,460,353	1,460,140	1,459,927	1,459,714	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,462,270	1,462,057	1,461,844	1,461,631	1,461,418	1,461,205	1,460,992	1,460,779	1,460,566	1,460,353	1,460,140	1,459,927	1,459,714	
6	Average Net Investment		1,462,164	1,461,951	1,461,738	1,461,525	1,461,312	1,461,099	1,460,886	1,460,673	1,460,460	1,460,247	1,460,034	1,459,821	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,743	10,741	10,739	10,738	10,736	10,735	10,733	10,732	10,730	10,728	10,727	10,725	128,807
	b Debt Component (Line 6 x Debt Component x 1/12)		3,052	3,051	3,051	3,050	3,050	3,049	3,049	3,048	3,048	3,048	3,047	3,047	36,590
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		213	213	213	213	213	213	213	213	213	213	213	213	2,556
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,008	14,005	14,003	14,001	13,999	13,997	13,995	13,993	13,991	13,989	13,987	13,985	167,953
	a Recoverable Costs Allocated to Energy		14,008	14,005	14,003	14,001	13,999	13,997	13,995	13,993	13,991	13,989	13,987	13,985	167,953
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		13,490	13,561	13,559	13,596	13,559	13,581	13,588	13,567	13,553	13,546	13,532	13,502	162,634
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		13,490	13,561	13,559	13,596	13,559	13,581	13,588	13,567	13,553	13,546	13,532	13,502	162,634

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	
3	Less: Accumulated Depreciation (C)	5,703,311	5,676,772	5,650,233	5,623,694	5,597,155	5,570,616	5,544,077	5,517,538	5,490,999	5,464,460	5,437,921	5,411,382	5,384,843	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	14,801,235	14,774,696	14,748,157	14,721,618	14,695,079	14,668,540	14,642,001	14,615,462	14,588,923	14,562,384	14,535,845	14,509,306	14,482,767	
6	Average Net Investment		14,787,966	14,761,427	14,734,888	14,708,349	14,681,810	14,655,271	14,628,732	14,602,193	14,575,654	14,549,115	14,522,576	14,496,037	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		108,647	108,452	108,257	108,062	107,867	107,672	107,477	107,282	107,087	106,892	106,697	106,502	1,290,894
	b Debt Component (Line 6 x Debt Component x 1/12)		30,862	30,807	30,752	30,696	30,641	30,586	30,530	30,475	30,419	30,364	30,309	30,253	366,694
8	Investment Expenses														
	a Depreciation (E)		26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	318,468
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		166,048	165,798	165,548	165,297	165,047	164,797	164,546	164,296	164,045	163,795	163,545	163,294	1,976,056
	a Recoverable Costs Allocated to Energy		166,048	165,798	165,548	165,297	165,047	164,797	164,546	164,296	164,045	163,795	163,545	163,294	1,976,056
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		159,904	160,538	160,301	160,515	159,863	159,896	159,765	159,294	158,908	158,605	158,224	157,653	1,913,466
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		159,904	160,538	160,301	160,515	159,863	159,896	159,765	159,294	158,908	158,605	158,224	157,653	1,913,466

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plnts Crist Scholz, Smith & Daniel
P.E.s 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 1592, 1658, 1829 & 1830
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		24,270	10,965	14,649	(1,068)	1,054	15,838	(5,215)	3,567	3,742	(2,843)	6,789	36,697	
	b Clearings to Plant		24,270	10,918	11,998	1,630	1,054	15,838	(5,215)	3,567	3,742	(2,843)	6,789	(275)	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	7,161,788	7,186,058	7,196,976	7,208,974	7,210,604	7,211,658	7,227,496	7,222,281	7,225,848	7,229,590	7,226,747	7,233,536	7,233,261	
3	Less: Accumulated Depreciation (C)	3,008,313	2,987,423	2,966,462	2,945,469	2,924,441	2,903,410	2,882,376	2,861,296	2,840,231	2,819,155	2,798,069	2,776,991	2,755,893	
4	CWIP - Non Interest Bearing	0	0	47	2,698	0	0	0	0	0	0	0	0	36,972	
5	Net Investment (Lines 2 + 3 + 4)	10,170,101	10,173,481	10,163,485	10,157,141	10,135,045	10,115,068	10,109,872	10,083,577	10,066,079	10,048,745	10,024,816	10,010,527	10,026,126	
6	Average Net Investment		10,171,791	10,168,483	10,160,313	10,146,093	10,125,057	10,112,470	10,096,725	10,074,828	10,057,412	10,036,781	10,017,672	10,018,327	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		74,731	74,708	74,648	74,543	74,390	74,297	74,182	74,020	73,892	73,741	73,600	73,607	890,359
	b Debt Component (Line 6 x Debt Component x 1/12)		21,229	21,222	21,205	21,175	21,131	21,105	21,072	21,026	20,990	20,947	20,907	20,908	252,917
8	Investment Expenses														
	a Depreciation (E)		20,662	20,733	20,765	20,800	20,803	20,806	20,852	20,837	20,848	20,858	20,850	20,870	249,684
	b Amortization (F)		228	228	228	228	228	228	228	228	228	228	228	228	2,736
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	15,048
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		118,104	118,145	118,100	118,000	117,806	117,690	117,588	117,365	117,212	117,028	116,839	116,867	1,410,744
	a Recoverable Costs Allocated to Energy		118,104	118,145	118,100	118,000	117,806	117,690	117,588	117,365	117,212	117,028	116,839	116,867	1,410,744
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		113,734	114,397	114,357	114,586	114,106	114,190	114,171	113,792	113,541	113,320	113,037	112,830	1,366,061
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		113,734	114,397	114,357	114,586	114,106	114,190	114,171	113,792	113,541	113,320	113,037	112,830	1,366,061

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $3,928,834; Scholz $916,802 Smith $1,734,877; Daniel $581,276. Ending Balances: Crist, $3,997,211; Scholz $916,802; Smith $1,734,877; Daniel $584,373.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist: 3.5%; Smith 3.3%; Scholz 4.1%; Daniel 2.8% annually
(F) PE 1364 & 1658 have a 7 year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Sub. Contam. Mobile Groundwater Treat. Sys.
P.E. 1007, 3400, & 3412
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	
3	Less: Accumulated Depreciation (C)	(243,560)	(245,243)	(246,926)	(248,609)	(250,292)	(251,975)	(253,658)	(255,341)	(257,024)	(258,707)	(260,390)	(262,073)	(263,756)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	674,464	672,781	671,098	669,415	667,732	666,049	664,366	662,683	661,000	659,317	657,634	655,951	654,268	
6	Average Net Investment		673,623	671,940	670,257	668,574	666,891	665,208	663,525	661,842	660,159	658,476	656,793	655,110	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,949	4,937	4,924	4,912	4,900	4,887	4,874	4,864	4,850	4,838	4,825	4,813	58,573
	b Debt Component (Line 6 x Debt Component x 1/12)		1,406	1,402	1,399	1,395	1,392	1,388	1,385	1,381	1,378	1,374	1,371	1,367	16,638
8	Investment Expenses														
	a Depreciation (E)		1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	20,196
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,038	8,022	8,006	7,990	7,975	7,958	7,942	7,928	7,911	7,895	7,879	7,863	95,407
	a Recoverable Costs Allocated to Energy		618	617	616	615	613	612	611	610	609	607	606	605	7,339
	b Recoverable Costs Allocated to Demand		7,420	7,405	7,390	7,375	7,362	7,346	7,331	7,318	7,302	7,288	7,273	7,258	88,068
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		595	597	596	597	594	594	593	591	590	588	586	584	7,105
13	Retail Demand-Related Recoverable Costs (I)		7,156	7,142	7,127	7,113	7,100	7,085	7,070	7,058	7,042	7,029	7,015	7,000	84,937
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,751	7,739	7,723	7,710	7,694	7,679	7,663	7,649	7,632	7,617	7,601	7,584	92,042

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Part of PE 1007 depreciable at 2.2% annually, PEs 3400 and 3412 depreciable at 2.2% annually
(F) The amortizable portion of PE 1007 is fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E. 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	
3	Less: Accumulated Depreciation (C)	(79,139)	(79,832)	(80,525)	(81,218)	(81,911)	(82,604)	(83,297)	(83,990)	(84,683)	(85,376)	(86,069)	(86,762)	(87,455)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	163,834	163,141	162,448	161,755	161,062	160,369	159,676	158,983	158,290	157,597	156,904	156,211	155,518	
6	Average Net Investment		163,488	162,795	162,102	161,409	160,716	160,023	159,330	158,637	157,944	157,251	156,558	155,865	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,201	1,196	1,191	1,186	1,181	1,176	1,170	1,167	1,160	1,155	1,150	1,145	14,078
	b Debt Component (Line 6 x Debt Component x 1/12)		341	340	338	337	335	334	333	331	330	328	327	325	3,999
8	Investment Expenses														
	a Depreciation (E)		693	693	693	693	693	693	693	693	693	693	693	693	8,316
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,235	2,229	2,222	2,216	2,209	2,203	2,196	2,191	2,183	2,176	2,170	2,163	26,393
	a Recoverable Costs Allocated to Energy		172	171	171	170	170	169	169	169	168	167	167	166	2,029
	b Recoverable Costs Allocated to Demand		2,063	2,058	2,051	2,046	2,039	2,034	2,027	2,022	2,015	2,009	2,003	1,997	24,364
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		166	166	166	165	165	164	164	164	163	162	162	160	1,967
13	Retail Demand-Related Recoverable Costs (I)		1,990	1,985	1,978	1,973	1,967	1,962	1,955	1,950	1,943	1,938	1,932	1,926	23,499
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,156	2,151	2,144	2,138	2,132	2,126	2,119	2,114	2,106	2,100	2,094	2,086	25,466

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,950; Smith $93,023.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5%; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	502,395	502,226	502,057	501,888	501,719	501,550	501,381	501,212	501,043	500,874	500,705	500,536	500,367	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	502,395	502,226	502,057	501,888	501,719	501,550	501,381	501,212	501,043	500,874	500,705	500,536	500,367	
6	Average Net Investment		502,311	502,142	501,973	501,804	501,635	501,466	501,297	501,128	500,959	500,790	500,621	500,452	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,690	3,689	3,688	3,687	3,686	3,684	3,683	3,682	3,681	3,679	3,678	3,677	44,204
	b Debt Component (Line 6 x Debt Component x 1/12)		1,048	1,048	1,048	1,047	1,047	1,047	1,046	1,046	1,046	1,045	1,045	1,044	12,557
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		169	169	169	169	169	169	169	169	169	169	169	169	2,028
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,907	4,906	4,905	4,903	4,902	4,900	4,898	4,897	4,896	4,893	4,892	4,890	58,789
	a Recoverable Costs Allocated to Energy		377	377	377	377	377	377	377	377	377	376	376	376	4,521
	b Recoverable Costs Allocated to Demand		4,530	4,529	4,528	4,526	4,525	4,523	4,521	4,520	4,519	4,517	4,516	4,514	54,268
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		363	365	365	366	365	366	366	366	365	364	364	363	4,378
13	Retail Demand-Related Recoverable Costs (I)		4,369	4,368	4,367	4,365	4,364	4,362	4,360	4,359	4,358	4,356	4,355	4,354	52,337
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,732	4,733	4,732	4,731	4,729	4,728	4,726	4,725	4,723	4,720	4,719	4,717	56,715

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248, 1180
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	400	28,570	40,094	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	800	2,176	(0)	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	
3	Less: Accumulated Depreciation (C)	(166,318)	(167,209)	(168,100)	(168,991)	(169,882)	(170,773)	(171,664)	(172,555)	(173,446)	(174,337)	(174,428)	(173,143)	(174,034)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	400	28,970	69,063	
5	Net Investment (Lines 2 + 3 + 4)	139,005	138,114	137,223	136,332	135,441	134,550	133,659	132,768	131,877	130,986	131,295	161,150	200,352	
6	Average Net Investment		138,560	137,669	136,778	135,887	134,996	134,105	133,214	132,323	131,432	131,140	146,222	180,751	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,018	1,011	1,005	998	992	985	979	972	966	962	1,075	1,328	12,291
	b Debt Component (Line 6 x Debt Component x 1/12)		289	287	285	284	282	280	278	276	274	274	305	377	3,491
8	Investment Expenses														
	a Depreciation (E)		891	891	891	891	891	891	891	891	891	891	891	891	10,692
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,198	2,189	2,181	2,173	2,165	2,156	2,148	2,139	2,131	2,127	2,271	2,596	26,474
	a Recoverable Costs Allocated to Energy		169	168	168	167	167	166	165	165	164	164	175	200	2,038
	b Recoverable Costs Allocated to Demand		2,029	2,021	2,013	2,006	1,998	1,990	1,983	1,974	1,967	1,963	2,096	2,396	24,436
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		163	163	163	162	162	161	160	160	159	159	169	193	1,974
13	Retail Demand-Related Recoverable Costs (I)		1,957	1,949	1,941	1,935	1,927	1,919	1,913	1,904	1,897	1,893	2,022	2,311	23,568
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,120	2,112	2,104	2,097	2,089	2,080	2,073	2,064	2,056	2,052	2,191	2,504	25,542

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(31,243)	(31,444)	(31,645)	(31,846)	(32,047)	(32,248)	(32,449)	(32,650)	(32,851)	(33,052)	(33,253)	(33,454)	(33,655)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	37,680	37,479	37,278	37,077	36,876	36,675	36,474	36,273	36,072	35,871	35,670	35,469	35,268	
6	Average Net Investment		37,580	37,379	37,178	36,977	36,776	36,575	36,374	36,173	35,972	35,771	35,570	35,369	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		277	275	273	271	270	269	267	266	264	263	261	260	3,216
	b Debt Component (Line 6 x Debt Component x 1/12)		78	78	78	77	77	76	76	75	75	75	74	74	913
8	Investment Expenses														
	a Depreciation (E)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		556	554	552	549	548	546	544	542	540	539	536	535	6,541
	a Recoverable Costs Allocated to Energy		43	43	42	42	42	42	42	42	42	41	41	41	503
	b Recoverable Costs Allocated to Demand		513	511	510	507	506	504	502	500	498	498	495	494	6,038
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		41	42	41	41	41	41	41	41	41	40	40	40	490
13	Retail Demand-Related Recoverable Costs (I)		495	493	492	489	488	486	484	482	480	480	477	476	5,822
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		536	535	533	530	529	527	525	523	521	520	517	516	6,312

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s); or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(55,220)	(55,516)	(55,812)	(56,108)	(56,404)	(56,700)	(56,996)	(57,292)	(57,588)	(57,884)	(58,180)	(58,476)	(58,772)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	46,275	45,979	45,683	45,387	45,091	44,795	44,499	44,203	43,907	43,611	43,315	43,019	42,723	
6	Average Net Investment		46,127	45,831	45,535	45,239	44,943	44,647	44,351	44,055	43,759	43,463	43,167	42,871	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		339	337	335	332	330	328	326	324	321	319	317	315	3,923
	b Debt Component (Line 6 x Debt Component x 1/12)		96	96	95	94	94	93	93	92	91	91	90	89	1,114
8	Investment Expenses														
	a Depreciation (E)		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		731	729	726	722	720	717	715	712	708	706	703	700	8,589
	a Recoverable Costs Allocated to Energy		56	56	56	56	55	55	55	55	54	54	54	54	660
	b Recoverable Costs Allocated to Demand		675	673	670	666	665	662	660	657	654	652	649	646	7,929
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		54	54	54	54	53	53	53	53	52	52	52	52	636
13	Retail Demand-Related Recoverable Costs (I)		651	649	646	642	641	638	637	634	631	629	626	623	7,647
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		705	703	700	696	694	691	690	687	683	681	678	675	8,283

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(32,713)	(32,887)	(33,061)	(33,235)	(33,409)	(33,583)	(33,757)	(33,931)	(34,105)	(34,279)	(34,453)	(34,627)	(34,801)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	26,830	26,656	26,482	26,308	26,134	25,960	25,786	25,612	25,438	25,264	25,090	24,916	24,742	
6	Average Net Investment		26,743	26,569	26,395	26,221	26,047	25,873	25,699	25,525	25,351	25,177	25,003	24,829	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		196	195	194	193	191	190	189	188	186	185	184	182	2,273
	b Debt Component (Line 6 x Debt Component x 1/12)		56	55	55	55	54	54	54	53	53	53	52	52	646
8	Investment Expenses														
	a Depreciation (E)		174	174	174	174	174	174	174	174	174	174	174	174	2,088
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		426	424	423	422	419	418	417	415	413	412	410	408	5,007
	a Recoverable Costs Allocated to Energy		33	33	33	32	32	32	32	32	32	32	32	31	386
	b Recoverable Costs Allocated to Demand		393	391	390	390	387	386	385	383	381	380	378	377	4,621
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		32	32	32	31	31	31	31	31	31	31	31	30	374
13	Retail Demand-Related Recoverable Costs (I)		379	377	376	376	373	372	371	369	367	366	365	364	4,455
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		411	409	408	407	404	403	402	400	398	397	396	394	4,829

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 & 1413
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(85,239)	(86,362)	(87,485)	(88,608)	(89,731)	(90,854)	(91,977)	(93,100)	(94,223)	(95,346)	(96,469)	(97,592)	(98,715)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	305,880	304,757	303,634	302,511	301,388	300,265	299,142	298,019	296,896	295,773	294,650	293,527	292,404	
6	Average Net Investment		305,319	304,196	303,073	301,950	300,827	299,704	298,581	297,458	296,335	295,212	294,089	292,966	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,243	2,235	2,227	2,218	2,210	2,202	2,194	2,185	2,177	2,169	2,161	2,152	26,373
	b Debt Component (Line 6 x Debt Component x 1/12)		637	635	633	630	628	625	623	621	618	616	614	611	7,491
8	Investment Expenses														
	a Depreciation (E)		1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	13,476
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,003	3,993	3,983	3,971	3,961	3,950	3,940	3,929	3,918	3,908	3,898	3,886	47,340
	a Recoverable Costs Allocated to Energy		4,003	3,993	3,983	3,971	3,961	3,950	3,940	3,929	3,918	3,908	3,898	3,886	47,340
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		3,855	3,866	3,857	3,856	3,837	3,833	3,826	3,809	3,795	3,784	3,771	3,752	45,841
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,855	3,866	3,857	3,856	3,837	3,833	3,826	3,809	3,795	3,784	3,771	3,752	45,841

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $284,622 and Smith $106,497.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5% annually; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	
3	Less: Accumulated Depreciation (C)	(1,304,450)	(1,312,102)	(1,319,754)	(1,327,406)	(1,335,058)	(1,342,710)	(1,350,362)	(1,358,014)	(1,365,666)	(1,373,318)	(1,380,970)	(1,388,622)	(1,396,274)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,478,150	1,470,498	1,462,846	1,455,194	1,447,542	1,439,890	1,432,238	1,424,586	1,416,934	1,409,282	1,401,630	1,393,978	1,386,326	
6	Average Net Investment		1,474,324	1,466,672	1,459,020	1,451,368	1,443,716	1,436,064	1,428,412	1,420,760	1,413,108	1,405,456	1,397,804	1,390,152	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,832	10,776	10,719	10,663	10,607	10,551	10,495	10,438	10,382	10,326	10,270	10,213	126,272
	b Debt Component (Line 6 x Debt Component x 1/12)		3,077	3,061	3,045	3,029	3,013	2,997	2,981	2,965	2,949	2,933	2,917	2,901	35,868
8	Investment Expenses														
	a Depreciation (E)		7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	91,824
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		21,561	21,489	21,416	21,344	21,272	21,200	21,128	21,055	20,983	20,911	20,839	20,766	253,964
	a Recoverable Costs Allocated to Energy		1,659	1,653	1,647	1,642	1,636	1,631	1,625	1,620	1,614	1,609	1,603	1,597	19,536
	b Recoverable Costs Allocated to Demand		19,902	19,836	19,769	19,702	19,636	19,569	19,503	19,435	19,369	19,302	19,236	19,169	234,428
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		1,598	1,601	1,595	1,594	1,585	1,582	1,578	1,571	1,563	1,558	1,551	1,542	18,918
13	Retail Demand-Related Recoverable Costs (I)		19,195	19,131	19,066	19,002	18,938	18,873	18,810	18,744	18,681	18,616	18,552	18,488	226,096
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		20,793	20,732	20,661	20,596	20,523	20,455	20,388	20,315	20,244	20,174	20,103	20,030	245,014

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E. 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	89,624	89,132	88,640	88,148	87,656	87,164	86,672	86,180	85,688	85,196	84,704	84,212	83,720	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	268,586	268,094	267,602	267,110	266,618	266,126	265,634	265,142	264,650	264,158	263,666	263,174	262,682	
6	Average Net Investment		268,340	267,848	267,356	266,864	266,372	265,880	265,388	264,896	264,404	263,912	263,420	262,928	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,971	1,968	1,964	1,961	1,956	1,953	1,949	1,946	1,943	1,939	1,935	1,932	23,417
	b Debt Component (Line 6 x Debt Component x 1/12)		560	559	558	557	556	555	554	553	552	551	550	549	6,654
8	Investment Expenses														
	a Depreciation (E)		492	492	492	492	492	492	492	492	492	492	492	492	5,904
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,023	3,019	3,014	3,010	3,004	3,000	2,995	2,991	2,987	2,982	2,977	2,973	35,975
	a Recoverable Costs Allocated to Energy		233	232	232	232	231	231	230	230	230	229	229	229	2,768
	b Recoverable Costs Allocated to Demand		2,790	2,787	2,782	2,778	2,773	2,769	2,765	2,761	2,757	2,753	2,748	2,744	33,207
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		224	225	225	225	224	224	223	223	223	222	222	221	2,681
13	Retail Demand-Related Recoverable Costs (I)		2,691	2,688	2,683	2,679	2,674	2,671	2,667	2,663	2,659	2,655	2,650	2,646	32,026
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,915	2,913	2,908	2,904	2,898	2,895	2,890	2,886	2,882	2,877	2,872	2,867	34,707

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1501, 1535, 1555, & 1819
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		584	7,681	146	2,479	266	415	17	603	(1,346)	0	0	0	
	b Clearings to Plant		0	0	0	0	0	34,288	17	603	(1,346)	0	0	0	
	c Retirements		0	0	0	0	0	10,458	1,283,208	0	0	0	0	0	
	d Cost of Removal		0	46,317	2,900	411	220	1,129	(1,084)	211	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	16,210,229	16,210,229	16,210,229	16,210,229	16,210,229	16,210,229	16,234,059	14,950,868	14,951,471	14,950,125	14,950,125	14,950,125	14,950,125	
3	Less: Accumulated Depreciation (C)	(5,965,442)	(6,012,256)	(6,012,753)	(6,056,667)	(6,103,070)	(6,149,664)	(6,184,891)	(4,949,637)	(4,993,302)	(5,037,180)	(5,081,055)	(5,124,930)	(5,168,805)	
4	CWIP - Non Interest Bearing	22,718	23,302	30,983	31,129	33,608	33,874	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,267,505	10,221,275	10,228,459	10,184,691	10,140,767	10,094,439	10,049,168	10,001,231	9,958,169	9,912,945	9,869,070	9,825,195	9,781,320	
6	Average Net Investment		10,244,390	10,224,867	10,206,575	10,162,729	10,117,603	10,071,804	10,025,200	9,979,700	9,935,557	9,891,008	9,847,133	9,803,258	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		75,266	75,122	74,989	74,666	74,334	73,998	73,654	73,321	72,997	72,669	72,347	72,025	885,388
	b Debt Component (Line 6 x Debt Component x 1/12)		21,380	21,339	21,301	21,210	21,115	21,020	20,923	20,828	20,736	20,643	20,551	20,459	251,505
8	Investment Expenses														
	a Depreciation (E)		37,818	37,818	37,818	37,818	37,818	37,818	37,874	34,880	34,882	34,879	34,879	34,879	439,181
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	107,952
	d Property Taxes		28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	343,176
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		172,058	171,873	171,702	171,288	170,861	170,430	170,045	166,623	166,209	165,785	165,371	164,957	2,027,202
	a Recoverable Costs Allocated to Energy		13,235	13,221	13,208	13,176	13,143	13,110	13,080	12,817	12,785	12,753	12,721	12,689	155,938
	b Recoverable Costs Allocated to Demand		158,823	158,652	158,494	158,112	157,718	157,320	156,965	153,806	153,424	153,032	152,650	152,268	1,871,264
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		12,745	12,802	12,789	12,795	12,730	12,720	12,700	12,427	12,385	12,349	12,307	12,251	151,000
13	Retail Demand-Related Recoverable Costs (I)		153,178	153,013	152,861	152,492	152,112	151,729	151,386	148,339	147,971	147,593	147,225	146,856	1,804,755
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		165,923	165,815	165,650	165,287	164,842	164,449	164,086	160,766	160,356	159,942	159,532	159,107	1,955,755

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 2.8% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601, 1620, 1638
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	
3	Less: Accumulated Depreciation (C)	(26,347)	(26,716)	(27,085)	(27,454)	(27,823)	(28,192)	(28,561)	(28,930)	(29,299)	(29,668)	(30,037)	(30,406)	(30,775)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	107,787	107,418	107,049	106,680	106,311	105,942	105,573	105,204	104,835	104,466	104,097	103,728	103,359	
6	Average Net Investment		107,603	107,234	106,865	106,496	106,127	105,758	105,389	105,020	104,651	104,282	103,913	103,544	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		791	788	785	782	779	777	774	772	769	766	763	761	9,307
	b Debt Component (Line 6 x Debt Component x 1/12)		225	224	223	222	221	221	220	219	218	218	217	216	2,644
8	Investment Expenses														
	a Depreciation (E)		369	369	369	369	369	369	369	369	369	369	369	369	4,428
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,385	1,381	1,377	1,373	1,369	1,367	1,363	1,360	1,356	1,353	1,349	1,346	16,379
	a Recoverable Costs Allocated to Energy		107	106	106	106	105	105	105	105	104	104	104	104	1,261
	b Recoverable Costs Allocated to Demand		1,278	1,275	1,271	1,267	1,264	1,262	1,258	1,255	1,252	1,249	1,245	1,242	15,118
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		103	103	103	103	102	102	102	102	101	101	101	100	1,223
13	Retail Demand-Related Recoverable Costs (I)		1,233	1,230	1,226	1,222	1,219	1,217	1,213	1,210	1,208	1,205	1,201	1,198	14,582
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,336	1,333	1,329	1,325	1,321	1,319	1,315	1,312	1,309	1,306	1,302	1,298	15,805

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) PE 4397 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 1158, 1167, 1199, 1250, 1287
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		164,994	39,911	3,126	(3,148)	818	25,993	(5,061)	1,394	9,630	18,729	57	(152)	
	b Clearings to Plant		0	0	617,713	(3,148)	818	13,393	(5,352)	14,284	6,586	(775)	68	(219)	
	c Retirements		0	0	0	5,663,816	0	0	4,975	0	0	0	0	0	
	d Cost of Removal		52,693	30,220	12,762	5,148	145	1,042	(919)	228	540	(417)	(54)	(33)	
	e Salvage		0	0	0	640,000	0	0	5,842	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	129,425,427	129,425,427	129,425,427	130,043,140	124,376,176	124,376,994	124,390,387	124,380,060	124,394,344	124,400,930	124,400,155	124,400,223	124,400,004	
3	Less: Accumulated Depreciation (C)	(20,439,998)	(20,799,294)	(21,181,063)	(21,580,290)	(16,965,117)	(17,362,232)	(17,758,452)	(18,157,540)	(18,554,583)	(18,951,318)	(19,349,029)	(19,746,375)	(20,143,700)	
4	CWIP - Non Interest Bearing	409,683	574,677	614,588	0	0	0	12,600	12,891	1	3,045	22,549	22,538	22,605	
5	Net Investment (Lines 2 + 3 + 4)	109,395,112	109,200,810	108,858,952	108,462,850	107,411,059	107,014,762	106,644,535	106,235,411	105,839,762	105,452,657	105,073,675	104,676,386	104,278,909	
6	Average Net Investment		109,297,961	109,029,881	108,660,901	107,936,955	107,212,911	106,829,649	106,439,973	106,037,587	105,646,210	105,263,166	104,875,031	104,477,648	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		803,012	801,043	798,331	793,013	787,694	784,877	782,014	779,058	776,183	773,369	770,517	767,597	9,416,708
	b Debt Component (Line 6 x Debt Component x 1/12)		228,105	227,545	226,775	225,264	223,753	222,953	222,140	221,300	220,484	219,684	218,874	218,045	2,674,922
8	Investment Expenses														
	a Depreciation (E)		376,955	376,955	376,955	378,757	362,226	362,228	362,268	362,237	362,241	362,260	362,258	362,258	4,407,598
	b Amortization (F)		2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	28,368
	c Dismantlement		32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	392,040
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,443,106	1,440,577	1,437,095	1,432,068	1,408,707	1,405,092	1,401,456	1,397,629	1,393,942	1,390,347	1,386,683	1,382,934	16,919,636
	a Recoverable Costs Allocated to Energy		1,443,106	1,440,577	1,437,095	1,432,068	1,408,707	1,405,092	1,401,456	1,397,629	1,393,942	1,390,347	1,386,683	1,382,934	16,919,636
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		1,389,708	1,394,875	1,391,547	1,390,635	1,364,464	1,363,309	1,360,733	1,355,075	1,350,290	1,346,294	1,341,563	1,335,159	16,383,652
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,389,708	1,394,875	1,391,547	1,390,635	1,364,464	1,363,309	1,360,733	1,355,075	1,350,290	1,346,294	1,341,563	1,335,159	16,383,652

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Portions of 1287 have 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E. 1272 & 1404
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	
3	Less: Accumulated Depreciation (C)	(122,100)	(124,810)	(127,520)	(130,230)	(132,940)	(135,650)	(138,360)	(141,070)	(143,780)	(146,490)	(149,200)	(151,910)	(154,620)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	807,579	804,869	802,159	799,449	796,739	794,029	791,319	788,609	785,899	783,189	780,479	777,769	775,059	
6	Average Net Investment		806,224	803,514	800,804	798,094	795,384	792,674	789,964	787,254	784,544	781,834	779,124	776,414	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,923	5,903	5,884	5,863	5,843	5,824	5,803	5,784	5,764	5,744	5,724	5,705	69,764
	b Debt Component (Line 6 x Debt Component x 1/12)		1,683	1,677	1,671	1,666	1,660	1,654	1,649	1,643	1,637	1,632	1,626	1,620	19,818
8	Investment Expenses														
	a Depreciation (E)		2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	32,520
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,316	10,290	10,265	10,239	10,213	10,188	10,162	10,137	10,111	10,086	10,060	10,035	122,102
	a Recoverable Costs Allocated to Energy		794	792	790	788	786	784	782	780	778	776	774	772	9,396
	b Recoverable Costs Allocated to Demand		9,522	9,498	9,475	9,451	9,427	9,404	9,380	9,357	9,333	9,310	9,286	9,263	112,706
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		765	767	765	765	761	761	759	756	754	751	749	745	9,098
13	Retail Demand-Related Recoverable Costs (I)		9,184	9,160	9,138	9,115	9,092	9,070	9,047	9,024	9,001	8,979	8,956	8,934	108,700
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		9,949	9,927	9,903	9,880	9,853	9,831	9,806	9,780	9,755	9,730	9,705	9,679	117,798

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $919,836; Smith $9,843. Ending Balances: Crist, $919,836; Smith $9,843.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5%; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1,297
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(14,120)	(14,303)	(14,486)	(14,669)	(14,852)	(15,035)	(15,218)	(15,401)	(15,584)	(15,767)	(15,950)	(16,133)	(16,316)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	48,750	48,567	48,384	48,201	48,018	47,835	47,652	47,469	47,286	47,103	46,920	46,737	46,554	
6	Average Net Investment		48,659	48,476	48,293	48,110	47,927	47,744	47,561	47,378	47,195	47,012	46,829	46,646	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		357	356	355	353	352	351	349	348	347	345	344	343	4,200
	b Debt Component (Line 6 x Debt Component x 1/12)		102	101	101	100	100	100	99	99	98	98	98	97	1,193
8	Investment Expenses														
	a Depreciation (E)		183	183	183	183	183	183	183	183	183	183	183	183	2,196
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		642	640	639	636	635	634	631	630	628	626	625	623	7,589
	a Recoverable Costs Allocated to Energy		642	640	639	636	635	634	631	630	628	626	625	623	7,589
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		618	620	619	618	615	615	613	611	608	606	605	601	7,349
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		618	620	619	618	615	615	613	611	608	606	605	601	7,349

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E. 1175, 1191, 1305, 1461, 1462
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	
3	Less: Accumulated Depreciation (C)	(3,307,193)	(3,391,674)	(3,476,155)	(3,560,636)	(3,645,117)	(3,729,598)	(3,814,079)	(3,898,560)	(3,983,041)	(4,067,522)	(4,152,003)	(4,236,484)	(4,320,965)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	26,532,485	26,448,004	26,363,523	26,279,042	26,194,561	26,110,080	26,025,599	25,941,118	25,856,637	25,772,156	25,687,675	25,603,194	25,518,713	
6	Average Net Investment		26,490,245	26,405,764	26,321,283	26,236,802	26,152,321	26,067,840	25,983,359	25,898,878	25,814,397	25,729,916	25,645,435	25,560,954	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		194,624	194,003	193,381	192,763	192,142	191,521	190,900	190,279	189,658	189,038	188,417	187,796	2,294,522
	b Debt Component (Line 6 x Debt Component x 1/12)		55,285	55,109	54,933	54,756	54,580	54,404	54,227	54,051	53,875	53,698	53,522	53,346	651,786
8	Investment Expenses														
	a Depreciation (E)		84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	1,013,772
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		334,390	333,593	332,795	332,000	331,203	330,406	329,608	328,811	328,014	327,217	326,420	325,623	3,960,080
	a Recoverable Costs Allocated to Energy		334,390	333,593	332,795	332,000	331,203	330,406	329,608	328,811	328,014	327,217	326,420	325,623	3,960,080
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		322,017	323,010	322,247	322,394	320,801	320,581	320,030	318,800	317,742	316,849	315,799	314,374	3,834,644
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		322,017	323,010	322,247	322,394	320,801	320,581	320,030	318,800	317,742	316,849	315,799	314,374	3,834,644

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $13,997,696; Smith $15,715,201; Scholz $126,781. Ending Balances: Crist, $13,997,696; Smith $15,715,201; Scholz $126,781.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5%; Smith 3.3%; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E. 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Scholz $0. Ending Balances: Crist, $0; Scholz $0.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5% annually; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.'s 1178, 1227, 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		3,044	34,656	52,896	112,822	111,072	31,256	19,034	18,139	28,554	36,088	116,851	217,243	
	b Clearings to Plant		3,044	34,656	52,896	112,822	111,072	31,256	19,034	18,139	28,554	35,590	62,767	85,741	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		23,393	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	19,041,725	19,044,769	19,079,425	19,132,321	19,245,143	19,356,215	19,387,471	19,406,505	19,424,644	19,453,198	19,488,788	19,551,555	19,637,296	
3	Less: Accumulated Depreciation (C)	(496,666)	(575,604)	(631,158)	(686,813)	(742,622)	(798,760)	(855,222)	(911,775)	(968,384)	(1,025,046)	(1,081,791)	(1,138,640)	(1,195,672)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	498	54,582	186,084	
5	Net Investment (Lines 2 + 3 + 4)	18,545,059	18,469,165	18,448,267	18,445,508	18,502,521	18,557,455	18,532,249	18,494,730	18,456,260	18,428,152	18,407,495	18,467,497	18,627,708	
6	Average Net Investment		18,507,112	18,458,716	18,446,888	18,474,015	18,529,988	18,544,852	18,513,490	18,475,495	18,442,206	18,417,824	18,437,496	18,547,603	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		135,972	135,616	135,529	135,729	136,140	136,249	136,019	135,739	135,495	135,315	135,461	136,269	1,629,533
	b Debt Component (Line 6 x Debt Component x 1/12)		38,624	38,523	38,499	38,555	38,672	38,703	38,638	38,558	38,489	38,438	38,479	38,709	462,887
8	Investment Expenses														
	a Depreciation (E)		55,545	55,554	55,655	55,809	56,138	56,462	56,553	56,609	56,662	56,745	56,849	57,032	675,613
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		230,141	229,693	229,683	230,093	230,950	231,414	231,210	230,906	230,646	230,498	230,789	232,010	2,768,033
	a Recoverable Costs Allocated to Energy		17,703	17,669	17,668	17,699	17,765	17,801	17,785	17,762	17,742	17,731	17,753	17,847	212,925
	b Recoverable Costs Allocated to Demand		212,438	212,024	212,015	212,394	213,185	213,613	213,425	213,144	212,904	212,767	213,036	214,163	2,555,108
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		17,048	17,108	17,108	17,187	17,207	17,272	17,268	17,221	17,186	17,169	17,175	17,230	206,179
13	Retail Demand-Related Recoverable Costs (I)		204,888	204,488	204,480	204,845	205,608	206,021	205,839	205,568	205,337	205,205	205,464	206,551	2,464,294
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		221,936	221,596	221,588	222,032	222,815	223,293	223,107	222,789	222,523	222,374	222,639	223,781	2,670,473

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Revised to exclude $73,956 that was incorrectly included in CWIP in December 2008 for PE 1298.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E. 1204 & 1299
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		607	1	2	(5)	0	0	0	0	0	0	26,977	20,854	
	b Clearings to Plant		607	1	2	(5)	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	6,017,436	6,018,043	6,018,044	6,018,046	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	
3	Less: Accumulated Depreciation (C)	(898,358)	(915,911)	(933,466)	(951,021)	(968,576)	(986,131)	(1,003,686)	(1,021,241)	(1,038,796)	(1,056,351)	(1,073,906)	(1,091,461)	(1,109,016)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	26,977	47,831	
5	Net Investment (Lines 2 + 3 + 4)	5,119,078	5,102,132	5,084,578	5,067,025	5,049,465	5,031,910	5,014,355	4,996,800	4,979,245	4,961,690	4,944,135	4,953,557	4,956,856	
6	Average Net Investment		5,110,605	5,093,355	5,075,802	5,058,245	5,040,688	5,023,133	5,005,578	4,988,023	4,970,468	4,952,913	4,948,846	4,955,207	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		37,549	37,421	37,292	37,162	37,034	36,905	36,776	36,647	36,518	36,389	36,360	36,406	442,459
	b Debt Component (Line 6 x Debt Component x 1/12)		10,666	10,630	10,593	10,557	10,520	10,483	10,447	10,410	10,373	10,337	10,328	10,342	125,686
8	Investment Expenses														
	a Depreciation (E)		17,553	17,555	17,555	17,555	17,555	17,555	17,555	17,555	17,555	17,555	17,555	17,555	210,658
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		65,768	65,606	65,440	65,274	65,109	64,943	64,778	64,612	64,446	64,281	64,243	64,303	778,803
	a Recoverable Costs Allocated to Energy		5,059	5,047	5,034	5,021	5,008	4,996	4,983	4,970	4,957	4,945	4,942	4,946	59,908
	b Recoverable Costs Allocated to Demand		60,709	60,559	60,406	60,253	60,101	59,947	59,795	59,642	59,489	59,336	59,301	59,357	718,895
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		4,872	4,887	4,874	4,876	4,851	4,847	4,838	4,819	4,802	4,788	4,781	4,775	58,010
13	Retail Demand-Related Recoverable Costs (I)		58,551	58,407	58,259	58,111	57,965	57,816	57,670	57,522	57,375	57,227	57,193	57,247	693,343
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		63,423	63,294	63,133	62,987	62,816	62,663	62,508	62,341	62,177	62,015	61,974	62,022	751,353

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1222, 1233, 1279, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1810, 1824, & 1826
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		97,363	57,400	170,944	51,720	1,294,602	78,722	8,217,661	1,870,686	316,669	47,056	474,040	134,693	
	b Clearings to Plant		53,693	56,426	201,558	349,712	1,294,602	78,722	8,217,661	1,870,686	293,406	47,057	474,041	157,955	
	c Retirements		57,921	0	84,294	0	0	0	0	86,852	0	0	0	0	
	d Cost of Removal		6,927	0	802,127	85,134	1,212	3,298	(3,241)	(40,465)	(3,216)	(5,191)	13,183	(1)	
	e Salvage		7,798	0	0	0	40,360	0	0	16,680	0	0	16,650	(3,465)	
2	Plant-in-Service/Depreciation Base (B)	627,568,922	627,564,694	627,621,120	627,738,384	628,088,096	629,382,698	629,461,420	637,679,081	639,462,915	639,756,321	639,803,378	640,277,419	640,435,374	
3	Less: Accumulated Depreciation (C)	(29,377,564)	(31,461,111)	(33,610,483)	(34,869,205)	(36,929,556)	(39,115,209)	(41,262,192)	(43,415,944)	(45,560,719)	(47,743,620)	(49,929,352)	(52,113,497)	(54,292,094)	
4	CWIP - Non Interest Bearing	283,963	327,633	328,607	297,993	0	0	0	0	0	23,263	23,262	23,261	(1)	
5	Net Investment (Lines 2 + 3 + 4)	598,475,321	596,431,216	594,339,244	593,167,172	591,158,540	590,267,489	588,199,228	594,263,137	593,902,196	592,035,964	589,897,288	588,187,183	586,143,279	
6	Average Net Investment		597,453,269	595,385,230	593,753,208	592,162,856	590,713,015	589,233,359	591,231,183	594,082,667	592,969,080	590,966,626	589,042,236	587,165,231	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,389,488	4,374,295	4,362,304	4,350,621	4,339,970	4,329,099	4,343,778	4,364,725	4,356,544	4,341,833	4,327,693	4,313,904	52,194,254
	b Debt Component (Line 6 x Debt Component x 1/12)		1,246,885	1,242,569	1,239,163	1,235,844	1,232,818	1,229,730	1,233,899	1,239,851	1,237,526	1,233,347	1,229,331	1,225,414	14,826,377
8	Investment Expenses														
	a Depreciation (E)		1,817,604	1,817,591	1,817,756	1,818,098	1,819,118	1,822,894	1,823,124	1,847,095	1,852,298	1,853,154	1,853,291	1,854,674	21,996,697
	b Amortization (F)		12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	149,880
	c Dismantlement		314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	3,778,764
	d Property Taxes		18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	217,944
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,799,526	7,780,004	7,764,772	7,750,112	7,737,455	7,727,272	7,746,350	7,797,220	7,791,917	7,773,883	7,755,864	7,739,541	93,163,916
	a Recoverable Costs Allocated to Energy		7,799,526	7,780,004	7,764,772	7,750,112	7,737,455	7,727,272	7,746,350	7,797,220	7,791,917	7,773,883	7,755,864	7,739,541	93,163,916
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		7,510,928	7,533,185	7,518,674	7,525,882	7,494,444	7,497,485	7,521,258	7,559,817	7,547,912	7,527,571	7,503,501	7,472,169	90,212,826
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,510,928	7,533,185	7,518,674	7,525,882	7,494,444	7,497,485	7,521,258	7,559,817	7,547,912	7,527,571	7,503,501	7,472,169	90,212,826

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $607,220,634; Smith $12,931,385; Daniel $6,772,682, Scholz $644,221. Ending Balances: Crist $620,086,561; Smith $12,931,385; Daniel $6,772,682, Scholz $644,221.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.5%, Plant Smith Steam 3.3%, Smith CT 3.6%, Daniel 2.8%, Scholz 4.1%. Portion of PE 1222 is transmission 2.0%, 2.3%, 3.5%, and 3.6%
(F) Portion of PE 1222 applicable 7 year amortization period beginning in 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Project #1222 qualifies for AFUDC treatment. As portions of the project are moved to P-I-S, they are included in the ECRC.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.1280
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	
3	Less: Accumulated Depreciation (C)	(15,866)	(16,400)	(16,934)	(17,468)	(18,002)	(18,536)	(19,070)	(19,604)	(20,138)	(20,672)	(21,206)	(21,740)	(22,274)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	16,155	15,621	15,087	14,553	14,019	13,485	12,951	12,417	11,883	11,349	10,815	10,281	9,747	
6	Average Net Investment		15,888	15,354	14,820	14,286	13,752	13,218	12,684	12,150	11,616	11,082	10,548	10,014	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		117	113	109	105	101	97	93	89	85	81	77	74	1,141
	b Debt Component (Line 6 x Debt Component x 1/12)		33	32	31	30	29	28	26	25	24	23	22	21	324
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		534	534	534	534	534	534	534	534	534	534	534	534	6,408
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		684	679	674	669	664	659	653	648	643	638	633	629	7,873
	a Recoverable Costs Allocated to Energy		53	52	52	51	51	51	50	50	49	49	49	48	605
	b Recoverable Costs Allocated to Demand		631	627	622	618	613	608	603	598	594	589	584	581	7,268
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		51	50	50	50	49	49	49	48	47	47	47	46	583
13	Retail Demand-Related Recoverable Costs (I)		609	605	600	596	591	586	582	577	573	568	563	560	7,010
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		660	655	650	646	640	635	631	625	620	615	610	606	7,593

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 5 year amortization beginning 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Mercury Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Equity Component has been grossed up for taxes. The approved ROE is 12%.
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Working Capital, Annual NOx Expenses
For Project: Annual NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	4,533,754	4,067,923	3,901,539	3,737,874	3,573,662	3,283,631	2,946,498	2,590,444	2,243,468	2,069,530	1,942,499	1,846,214	1,675,143	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	4,533,754	4,067,923	3,901,539	3,737,874	3,573,662	3,283,631	2,946,498	2,590,444	2,243,468	2,069,530	1,942,499	1,846,214	1,675,143	
4	Average Net Working Capital Balance		4,300,839	3,984,731	3,819,707	3,655,768	3,428,647	3,115,065	2,768,471	2,416,956	2,156,499	2,006,015	1,894,357	1,760,679	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		31,598	29,276	28,063	26,859	25,190	22,886	20,340	17,757	15,844	14,738	13,918	12,936	259,405
	b Debt Component (Line 4 x Debt Component x 1/12)		8,976	8,316	7,972	7,630	7,156	6,501	5,778	5,044	4,501	4,187	3,954	3,675	73,690
6	Total Return Component (D)		40,574	37,592	36,035	34,489	32,346	29,387	26,118	22,801	20,345	18,925	17,872	16,611	333,095
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		465,831	166,384	163,665	164,212	290,031	337,133	356,054	346,976	173,938	127,031	96,285	171,071	2,858,611
8	Net Expenses (E)		465,831	166,384	163,665	164,212	290,031	337,133	356,054	346,976	173,938	127,031	96,285	171,071	2,858,611
9	Total System Recoverable Expenses (Lines 6 + 8)		506,405	203,976	199,700	198,701	322,377	366,520	382,172	369,777	194,283	145,956	114,157	187,682	3,191,706
	a Recoverable Costs Allocated to Energy		506,405	203,976	199,700	198,701	322,377	366,520	382,172	369,777	194,283	145,956	114,157	187,682	3,191,706
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		487,667	197,505	193,371	192,952	312,252	355,621	371,067	358,518	188,199	141,331	110,443	181,198	3,090,124
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		487,667	197,505	193,371	192,952	312,252	355,621	371,067	358,518	188,199	141,331	110,443	181,198	3,090,124

Notes:
(A) Equity Component has been grossed up for taxes. The approved ROE is 12%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	3,713	(583)	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	4,600	4,600	4,600	4,600	4,600	3,876	2,738	1,547	331	0	18	24	24	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	4,600	4,600	4,600	4,600	4,600	3,876	2,738	1,547	331	0	18	24	24	
4	Average Net Working Capital Balance		4,600	4,600	4,600	4,600	4,238	3,307	2,143	939	166	9	21	24	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		34	34	34	34	31	24	16	7	1	0	0	0	215
	b Debt Component (Line 4 x Debt Component x 1/12)		10	10	10	10	9	7	4	2	0	0	0	0	62
6	Total Return Component (D)		44	44	44	44	40	31	20	9	1	0	0	0	277
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		0	0	0	0	724	1,138	1,191	1,216	4,044	(601)	(6)	0	7,706
8	Net Expenses (E)		0	0	0	0	724	1,138	1,191	1,216	4,044	(601)	(6)	0	7,706
9	Total System Recoverable Expenses (Lines 6 + 8)		44	44	44	44	764	1,169	1,211	1,225	4,045	(601)	(6)	0	7,983
	a Recoverable Costs Allocated to Energy		44	44	44	44	764	1,169	1,211	1,225	4,045	(601)	(6)	0	7,983
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		42	43	43	43	740	1,134	1,176	1,188	3,918	(582)	(6)	0	7,739
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		42	43	43	43	740	1,134	1,176	1,188	3,918	(582)	(6)	0	7,739

Notes:
(A) Equity Component has been grossed up for taxes. The approved ROE is 12%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2011 - December 2011

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	2,643	0	0	0	0	0	13,387	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	9,765,386	9,677,874	9,610,967	9,551,173	9,466,550	9,339,733	9,220,313	9,048,186	8,888,433	8,839,313	8,821,043	8,801,613	8,657,438	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(910,417)	(900,944)	(891,471)	(884,392)	(874,670)	(864,948)	(855,226)	(845,504)	(835,782)	(827,223)	(817,501)	(807,779)	(798,057)	
3	Total Working Capital Balance	8,854,969	8,776,930	8,719,496	8,666,781	8,591,880	8,474,785	8,365,087	8,202,682	8,052,651	8,012,090	8,003,542	7,993,834	7,859,381	
4	Average Net Working Capital Balance		8,815,950	8,748,213	8,693,139	8,629,331	8,533,333	8,419,936	8,283,885	8,127,667	8,032,371	8,007,816	7,998,688	7,926,608	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		64,771	64,273	63,868	63,400	62,694	61,861	60,862	59,714	59,014	58,833	58,766	58,237	736,293
	b Debt Component (Line 4 x Debt Component x 1/12)		18,399	18,258	18,143	18,009	17,809	17,572	17,288	16,962	16,764	16,712	16,693	16,543	209,152
6	Total Return Component (D)		83,170	82,531	82,011	81,409	80,503	79,433	78,150	76,676	75,778	75,545	75,459	74,780	945,445
7	Expenses														
	a Gains		(9,473)	(9,473)	(9,722)	(9,722)	(9,722)	(9,722)	(9,722)	(9,722)	(21,946)	(9,722)	(9,722)	(9,722)	(128,390)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		87,512	66,907	59,794	84,623	126,817	119,420	172,127	159,753	49,120	18,270	19,430	144,175	1,107,948
8	Net Expenses (E)		78,039	57,434	50,072	74,901	117,095	109,698	162,405	150,031	27,174	8,548	9,708	134,453	979,558
9	Total System Recoverable Expenses (Lines 6 + 8)		161,209	139,965	132,083	156,310	197,598	189,131	240,555	226,707	102,952	84,093	85,167	209,233	1,925,003
	a Recoverable Costs Allocated to Energy		161,209	139,965	132,083	156,310	197,598	189,131	240,555	226,707	102,952	84,093	85,167	209,233	1,925,003
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9702630	0.9688747	0.9680072	0.9676381	0.9667849	0.9647784	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		155,244	135,525	127,897	151,788	191,392	183,507	233,565	219,804	99,728	81,429	82,396	202,005	1,864,280
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		155,244	135,525	127,897	151,788	191,392	183,507	233,565	219,804	99,728	81,429	82,396	202,005	1,864,280

Notes:
(A) Equity Component has been grossed up for taxes. The approved ROE is 12%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Schedule 9A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual True-Up Amount
January 2011 - December 2011
FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Column:
(1) Capital Structure Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

Schedule 1E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period True-Up Amount
January 2012 - December 2012

Line No.		Period Amound ($)
1	Over/(Under) Recovery for the current period (Schedule 2E, Line 5)	7,445,369
2	Interest Provision (Schedule 2E, Line 6)	7,990
3	Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2013 - December 2013 (Lines 1 + 2)	7,453,359

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 36
PARTY Gulf Power Company
DESCRIPTION R.W. Dodd (RWD-2), Calculation of Estimated)
DATE True-up 1/12-12/12

Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)

January 2012 - December 2012
Calculation of the Current Period True-Up Amount
Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	9,595,810	9,152,188	9,839,130	9,850,559	12,614,664	13,137,617	15,156,177	14,593,576	13,307,164	11,139,881	9,536,484	11,005,113	138,928,364
2	True-Up Provision (Order No. PSC-10-0683-FOF-EI)	1,270,153	1,270,153	1,270,153	1,270,153	1,270,153	1,270,153	1,270,153	1,270,153	1,270,153	1,270,153	1,270,153	1,270,155	15,241,838
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	10,865,963	10,422,341	11,109,283	11,120,712	13,884,817	14,407,770	16,426,330	15,863,729	14,577,317	12,410,034	10,806,637	12,275,268	154,170,202
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	1,757,628	1,110,008	1,357,017	1,650,303	1,912,575	1,744,868	1,582,219	1,787,266	1,545,619	1,665,763	1,917,297	5,042,755	23,073,318
	b Capital Investment Projects (Schedule 7E, Line 9)	10,077,875	10,112,292	10,161,482	9,822,744	10,409,232	10,454,375	10,447,785	10,446,879	10,460,926	10,456,654	10,409,435	10,391,836	123,651,515
	c **Total Jurisdictional ECRC Costs**	11,835,503	11,222,300	11,518,499	11,473,047	12,321,807	12,199,243	12,030,004	12,234,145	12,006,545	12,122,417	12,326,732	15,434,591	146,724,833
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	(969,540)	(799,959)	(409,216)	(352,335)	1,563,010	2,208,527	4,396,326	3,629,584	2,570,772	287,617	(1,520,095)	(3,159,323)	7,445,369
6	Interest Provision (Schedule 3E, Line 10)	557	555	342	279	260	365	644	987	1,216	1,236	1,000	549	7,990
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2011	9,104,881	6,865,745	4,796,188	3,117,162	1,494,952	1,788,070	2,726,809	5,853,626	8,214,044	9,515,879	8,534,579	5,745,331	9,104,881
	b Final True-Up from January 2010 - December 2010 (Order No. PSC-11-0553-FOF-EI)	861,325	861,325	861,325	861,325	861,325	861,325	861,325	861,325	861,325	861,325	861,325	861,325	861,325
8	True-Up Collected/(Refunded) (see Line 2)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,153)	(1,270,155)	(15,241,838)
	Annual NOx Allowance Expense													
9	Adjustments													
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	7,727,070	5,657,513	3,978,487	2,356,277	2,649,395	3,588,134	6,714,951	9,075,369	10,377,204	9,395,904	6,606,656	2,177,727	2,177,727

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period True-Up Amount
January 2012 - December 2012

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Beg. True-Up Amount (Schedule 2E, Lines 7a + 7b)	9,966,206	7,727,070	5,657,513	3,978,487	2,356,277	2,649,395	3,588,134	6,714,951	9,075,369	10,377,204	9,395,904	6,606,656	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	7,726,513	5,656,958	3,978,145	2,355,998	2,649,135	3,587,769	6,714,307	9,074,382	10,375,988	9,394,668	6,605,656	2,177,178	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	17,692,719	13,384,028	9,635,658	6,334,485	5,005,412	6,237,163	10,302,440	15,789,332	19,451,356	19,771,871	16,001,559	8,783,833	
4	Average True-Up Amount (Line 3 x 1/2)	8,846,359	6,692,014	4,817,829	3,167,243	2,502,706	3,118,582	5,151,220	7,894,666	9,725,678	9,885,936	8,000,780	4,391,917	
5	Interest Rate (First Day of Reporting Business Month)	0.000300	0.001200	0.000800	0.000900	0.001200	0.001300	0.001500	0.001500	0.001500	0.001500	0.001500	0.001500	
6	Interest Rate (First Day of Subsequent Business Month)	0.001200	0.000800	0.000900	0.001200	0.001300	0.001500	0.001500	0.001500	0.001500	0.001500	0.001500	0.001500	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.001500	0.002000	0.001700	0.002100	0.002500	0.002800	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	
8	Average Interest Rate (Line 7 x 1/2)	0.000750	0.001000	0.000850	0.001050	0.001250	0.001400	0.001500	0.001500	0.001500	0.001500	0.001500	0.001500	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.000063	0.000083	0.000071	0.000088	0.000104	0.000117	0.000125	0.000125	0.000125	0.000125	0.000125	0.000125	
10	Interest Provision for the Month (Line 4 x Line 9)	557	555	342	279	260	365	644	987	1,216	1,236	1,000	549	7,990

Schedule 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Variance Report of O & M Activities
(in Dollars)

Line		(1) Estimated/ Actual	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1	Description of O & M Activities				
.1	Sulfur	0	0	0	0.0 %
.2	Air Emission Fees	703,164	825,374	(122,210)	(14.8) %
.3	Title V	122,994	121,936	1,058	0.9 %
.4	Asbestos Fees	1,300	1,400	(100)	(7.1) %
.5	Emission Monitoring	615,446	640,443	(24,997)	(3.9) %
.6	General Water Quality	870,451	898,066	(27,615)	(3.1) %
.7	Groundwater Contamination Investigation	2,175,490	2,083,868	91,622	4.4 %
.8	State NPDES Administration	34,894	34,500	394	1.1 %
.9	Lead and Copper Rule	10,328	16,480	(6,152)	(37.3) %
.10	Env Auditing/Assessment	6,149	7,000	(851)	(12.2) %
.11	General Solid & Hazardous Waste	661,808	457,994	203,814	44.5 %
.12	Above Ground Storage Tanks	142,882	162,457	(19,575)	(12.0) %
.13	Low NOx	0	0	0	0.0 %
.14	Ash Pond Diversion Curtains	0	0	0	0.0 %
.15	Mercury Emissions	0	0	0	0.0 %
.16	Sodium Injection	41,693	74,000	(32,307)	(43.7) %
.17	Gulf Coast Ozone Study	0	0	0	0.0 %
.18	SPCC Substation Project	0	0	0	0.0 %
.19	FDEP NOx Reduction Agreement	2,039,260	1,673,050	366,210	21.9 %
.20	CAIR/CAMR/CAVR Compliance Program	14,938,703	16,384,916	(1,446,213)	(8.8) %
.21	MACT ICR	0	0	0	0.0 %
.22	Crist Water Conservation	187,117	156,000	31,117	19.9 %
.23	Mercury Allowances	0	0	0	0.0 %
.24	Annual NOx Allowances	722,012	103,671	618,341	596.4 %
.25	Seasonal NOx Allowances	20	1,719,025	(1,719,005)	(100.0) %
.26	SO2 Allowances	550,977	716,998	(166,021)	(23.2) %
2	Total O & M Activities	23,824,688	26,077,178	(2,252,490)	(8.6) %
3	Recoverable Costs Allocated to Energy	19,734,269	22,259,413	(2,525,144)	(11.3) %
4	Recoverable Costs Allocated to Demand	4,090,419	3,817,765	272,654	7.1 %

Notes:

Column (1) is the End of Period Totals on Schedule 5E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

O & M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
	.1 Sulfur	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.2 Air Emission Fees	510,720	68,070	-	-	-	-	-	-	-	-	124,374	-	703,164	0	703,164
	.3 Title V	9,018	8,556	9,735	11,818	11,888	9,744	9,028	9,828	10,278	10,028	12,793	10,278	122,994	0	122,994
	.4 Asbestos Fees	-	-	-	-	-	-	-	-	-	1,300	-	-	1,300	1,300	0
	.5 Emission Monitoring	47,612	36,120	42,885	40,158	73,994	57,649	42,820	53,820	47,820	43,320	83,428	45,820	615,446	0	615,446
	.6 General Water Quality	63,676	42,889	76,953	48,383	62,282	76,081	53,087	103,862	89,950	87,378	80,983	84,927	870,451	870,451	0
	.7 Groundwater Contamination Investigation	91,957	141,545	194,613	626,218	392,978	71,288	107,268	112,268	110,468	97,268	115,119	114,500	2,175,490	2,175,490	0
	.8 State NPDES Administration	-	394	-	-	-	-	-	-	-	-	-	34,500	34,894	34,894	0
	.9 Lead and Copper Rule	-	(3,596)	-	3,300	724	3,300	3,300	-	-	-	3,300	-	10,328	10,328	0
	.10 Env Auditing/Assessment	-	-	-	-	20	129	-	-	6,000	-	-	-	6,149	6,149	0
	.11 General Solid & Hazardous Waste	76,733	54,194	68,563	73,585	77,461	90,967	68,449	24,489	27,589	24,489	40,133	35,156	661,808	661,808	0
	.12 Above Ground Storage Tanks	5,277	198	3,678	2,993	4,228	5,226	3,022	5,022	26,022	53,912	32,783	521	142,882	142,882	0
	.13 Low NOx	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.17 Gulf Coast Ozone Study	-	-	-	-	-	8,692	10,333	1,000	9,333	1,000	10,335	1,000	41,693	0	41,693
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.19 FDEP NOx Reduction Agreement	163,430	136,615	68,771	140,421	113,712	160,006	150,550	184,916	209,598	228,254	247,109	235,878	2,039,260	0	2,039,260
	.20 CAIR/CAMR/CAVR Compliance Program	794,868	633,184	832,073	644,385	1,087,987	1,217,083	986,084	1,149,219	905,002	1,041,366	1,121,176	4,526,276	14,938,703	0	14,938,703
	.21 MACT ICR	-	-	-	-	-	618	(618)	-	-	-	-	-	0	0	0
	.22 Crist Water Conservation	1,023	(233)	27,531	(690)	19,230	3,116	23,160	23,160	19,440	19,440	19,440	32,500	187,117	187,117	0
	.23 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.24 Annual NOx Allowances	43,849	34,466	51,010	75,214	89,608	64,191	77,400	76,501	59,694	55,254	45,529	49,296	722,012	0	722,012
	.25 Seasonal NOx Allowances	-	-	-	-	5	4	4	4	3	-	-	-	20	0	20
	.26 SO2 Allowances	14,172	(3,874)	27,018	39,049	34,173	25,085	95,855	98,882	71,834	55,640	47,271	45,872	550,977	0	550,977
2	Total of O & M Activities	1,822,335	1,148,528	1,402,830	1,704,834	1,968,290	1,793,179	1,629,742	1,842,971	1,593,031	1,718,649	1,983,773	5,216,524	23,824,688	4,090,419	19,734,269
3	Recoverable Costs Allocated to Energy	1,583,669	913,137	1,031,492	951,045	1,411,367	1,543,072	1,371,456	1,574,170	1,313,562	1,434,862	1,692,015	4,914,420	19,734,269		
4	Recoverable Costs Allocated to Demand	238,666	235,391	371,338	753,789	556,923	250,107	258,286	268,801	279,469	283,787	291,758	302,104	4,090,419		
5	Retail Energy Jurisdictional Factor	0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995			
6	Retail Demand Jurisdictional Factor	0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346			
7	Jurisdictional Energy Recoverable Costs (A)	1,527,444	882,983	998,877	922,343	1,374,735	1,503,331	1,332,783	1,527,676	1,275,726	1,391,700	1,635,536	4,751,003	19,124,137		
8	Jurisdictional Demand Recoverable Costs (B)	230,184	227,025	358,140	727,960	537,840	241,537	249,436	259,590	269,893	274,063	281,761	291,752	3,949,181		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,757,628	1,110,008	1,357,017	1,650,303	1,912,575	1,744,868	1,582,219	1,787,266	1,545,619	1,665,763	1,917,297	5,042,755	23,073,318		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 6E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Variance Report of Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		(1) Estimated/ Actual	(2) Original Projected	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
.1	Air Quality Assurance Testing	60,685	62,314	(1,629)	(2.6) %
.2	Crist 5, 6 & 7 Precipitator Projects	4,638,035	6,294,497	(1,656,462)	(26.3) %
.3	Crist 7 Flue Gas Conditioning	143,796	167,663	(23,867)	(14.2) %
.4	Low NOx Burners, Crist 6 & 7	1,706,276	1,940,009	(233,733)	(12.0) %
.5	CEMS - Plants Crist, Scholz, Smith, & Daniel	1,241,670	1,390,239	(148,569)	(10.7) %
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	92,939	100,872	(7,933)	(7.9) %
.7	Raw Water Well Flowmeters - Plants Crist & Smith	22,992	25,451	(2,459)	(9.7) %
.8	Crist Cooling Tower Cell	50,388	58,559	(8,171)	(14.0) %
.9	Crist Dechlorination System	34,323	46,553	(12,230)	(26.3) %
.10	Crist Diesel Fuel Oil Remediation	5,716	6,268	(552)	(8.8) %
.11	Crist Bulk Tanker Unload Sec Contain Struc	7,527	8,188	(661)	(8.1) %
.12	Crist IWW Sampling System	4,390	4,770	(380)	(8.0) %
.13	Sodium Injection System	41,173	45,815	(4,642)	(10.1) %
.14	Smith Stormwater Collection System	221,837	243,568	(21,731)	(8.9) %
.15	Smith Waste Water Treatment Facility	31,069	35,308	(4,239)	(12.0) %
.16	Daniel Ash Management Project	1,778,085	2,022,045	(243,960)	(12.1) %
.17	Smith Water Conservation	14,234	784,279	(770,045)	(98.2) %
.18	Underground Fuel Tank Replacement	0	0	0	0.0 %
.19	Crist FDEP Agreement for Ozone Attainment	14,679,514	16,373,062	(1,693,548)	(10.3) %
.20	SPCC Compliance	106,387	118,421	(12,034)	(10.2) %
.21	Crist Common FTIR Monitor	6,604	7,343	(739)	(10.1) %
.22	Precipitator Upgrades for CAM Compliance	3,438,202	3,845,311	(407,109)	(10.6) %
.23	Plant Groundwater Contamination	0	0	0	0.0 %
.24	Crist Water Conservation	2,483,480	2,768,441	(284,961)	(10.3) %
.25	Plant NPDES Permit Compliance Projects	691,307	783,719	(92,412)	(11.8) %
.26	CAIR/CAMR/CAVR Compliance	95,174,562	106,499,709	(11,325,147)	(10.6) %
.27	General Water Quality	7,055	7,150	(95)	(1.3) %
.28	Mercury Allowances	0	0	0	0.0 %
.29	Annual NOx Allowances	129,398	143,568	(14,170)	(9.9) %
.30	Seasonal NOx Allowances	0	0	0	0.0 %
.31	SO2 Allowances	741,420	821,059	(79,639)	(9.7) %
2	Total Investment Projects - Recoverable Costs	127,553,064	144,604,181	(17,051,117)	(11.8) %
3	Recoverable Costs Allocated to Energy	122,428,391	138,130,095	(15,701,704)	(11.4) %
4	Recoverable Costs Allocated to Demand	5,124,673	6,474,086	(1,349,413)	(20.8) %

Notes:
Column (1) is the End of Period Totals on Schedule 7E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-11-0553-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	5,411	5,373	5,333	5,144	5,038	5,007	4,975	4,944	4,912	4,881	4,849	4,818	60,685	0	60,685
	.2 Crist 5, 6 & 7 Precipitator Projects	227,877	267,234	334,215	350,468	421,637	420,192	432,000	438,518	437,702	436,854	436,002	435,336	4,638,035	0	4,638,035
	.3 Crist 7 Flue Gas Conditioning	13,983	13,981	13,979	12,132	11,220	11,219	11,218	11,216	11,214	11,213	11,211	11,210	143,796	0	143,796
	.4 Low NOx Burners, Crist 6 & 7	163,044	162,793	162,543	144,105	134,925	134,725	134,524	134,324	134,124	133,923	133,723	133,523	1,706,276	0	1,706,276
	.5 CEMS - Plants Crist, Scholz, Smith, & Daniel	116,847	116,740	117,153	104,792	98,833	98,674	98,513	98,350	98,187	98,024	97,860	97,697	1,241,670	0	1,241,670
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	7,848	7,831	7,816	6,981	6,563	6,550	6,538	6,525	7,753	9,528	9,511	9,495	92,939	85,790	7,149
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,157	2,150	2,144	1,944	1,843	1,837	1,832	1,827	1,822	1,817	1,812	1,807	22,992	21,223	1,769
	.8 Crist Cooling Tower Cell	4,889	4,887	4,885	4,253	3,939	3,937	3,936	3,935	3,934	3,932	3,931	3,930	50,388	46,512	3,876
	.9 Crist Dechlorination System	2,845	3,173	3,232	2,985	2,836	2,774	2,767	2,759	2,751	2,742	2,734	2,725	34,323	31,682	2,641
	.10 Crist Diesel Fuel Oil Remediation	532	531	529	483	461	458	457	456	454	453	452	450	5,716	5,276	440
	.11 Crist Bulk Tanker Unload Sec Contain Struc	698	695	692	637	608	606	604	602	599	598	595	593	7,527	6,948	579
	.12 Crist IWW Sampling System	406	405	404	372	355	354	352	351	350	348	347	346	4,390	4,052	338
	.13 Sodium Injection System	3,876	3,866	3,855	3,480	3,292	3,283	3,275	3,266	3,258	3,249	3,241	3,232	41,173	0	41,173
	.14 Smith Stormwater Collection System	20,694	20,622	20,550	18,759	17,854	17,796	17,738	17,680	17,623	17,565	17,507	17,449	221,837	204,773	17,064
	.15 Smith Waste Water Treatment Facility	2,968	2,963	2,959	2,624	2,457	2,454	2,450	2,446	2,443	2,439	2,435	2,431	31,069	28,679	2,390
	.16 Daniel Ash Management Project	163,334	162,920	162,506	149,923	143,583	143,253	142,922	142,591	142,260	141,928	141,598	141,267	1,778,085	1,641,309	136,776
	.17 Smith Water Conservation	1,342	1,339	1,336	1,203	1,136	1,134	1,131	1,129	1,125	1,122	1,120	1,117	14,234	13,139	1,095
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist FDEP Agreement for Ozone Attainment	1,379,339	1,375,333	1,371,158	1,237,436	1,170,492	1,167,861	1,165,580	1,165,998	1,164,620	1,163,211	1,161,188	1,157,298	14,679,514	0	14,679,514
	.20 SPCC Compliance	10,009	9,983	9,958	8,964	8,466	8,446	8,426	8,432	8,456	8,436	8,416	8,395	106,387	98,203	8,184
	.21 Crist Common FTIR Monitor	621	620	618	558	528	527	525	524	523	521	520	519	6,604	0	6,604
	.22 Precipitator Upgrades for CAM Compliance	324,826	324,029	323,232	290,553	274,177	273,539	272,901	272,264	271,626	270,989	270,352	269,714	3,438,202	0	3,438,202
	.23 Plant Groundwater Contamination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	233,003	233,100	233,078	209,230	197,295	196,955	197,739	197,499	197,057	196,616	196,175	195,733	2,483,480	2,292,444	191,036
	.25 Plant NPDES Permit Compliance Projects	64,441	64,655	64,694	58,264	55,023	55,289	55,162	55,027	54,892	54,755	54,620	54,485	691,307	638,130	53,177
	.26 CAIR/CAMR/CAVR Compliance	7,607,570	7,583,766	7,558,974	7,438,281	8,057,590	8,108,301	8,119,795	8,129,331	8,140,134	8,152,840	8,145,102	8,132,878	95,174,562	0	95,174,562
	.27 General Water Quality	624	619	614	598	589	585	581	577	573	569	565	561	7,055	6,513	542
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual NOx Allowances	15,596	15,228	14,824	12,323	10,759	10,179	9,644	9,064	8,550	8,117	7,736	7,378	129,398	0	129,398
	.30 Seasonal NOx Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.31 SO2 Allowances	74,079	74,030	73,921	63,744	58,597	58,372	57,917	57,182	56,538	56,056	55,668	55,316	741,420	0	741,420
2	Total Investment Projects - Recoverable Costs	10,448,859	10,458,866	10,495,202	10,130,236	10,690,096	10,734,307	10,753,502	10,766,817	10,773,480	10,782,726	10,769,270	10,749,703	127,553,064	5,124,673	122,428,391
3	Recoverable Costs Allocated to Energy	9,972,745	9,982,674	10,019,451	9,698,959	10,281,165	10,325,911	10,344,915	10,358,969	10,365,395	10,373,944	10,361,437	10,342,826	122,428,391		
4	Recoverable Costs Allocated to Demand	476,114	476,192	475,751	431,277	408,931	408,396	408,587	407,848	408,085	408,782	407,833	406,877	5,124,673		
5	Retail Energy Jurisdictional Factor	0.9638722	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995			
6	Retail Demand Jurisdictional Factor	0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346			
7	Jurisdictional Energy Recoverable Costs (B)	9,618,682	9,653,025	9,702,640	9,406,245	10,014,313	10,059,973	10,053,198	10,053,006	10,066,824	10,061,879	10,015,577	9,998,901	118,704,263		
8	Jurisdictional Demand Recoverable Costs (C)	459,193	459,267	458,842	416,499	394,919	394,402	394,587	393,873	394,102	394,775	393,858	392,935	4,947,252		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	10,077,875	10,112,292	10,161,482	9,822,744	10,409,232	10,454,375	10,447,785	10,446,879	10,460,926	10,456,654	10,409,435	10,391,836	123,651,515		

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9, Pages 28-31 of Schedule 8E, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	
3	Less: Accumulated Depreciation (C)	(217,739)	(221,915)	(226,092)	(230,268)	(234,444)	(238,621)	(242,797)	(246,973)	(251,150)	(255,326)	(259,502)	(263,679)	(267,855)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	133,073	128,897	124,720	120,544	116,368	112,191	108,015	103,839	99,662	95,486	91,310	87,133	82,957	
6	Average Net Investment		130,985	126,809	122,632	118,456	114,280	110,103	105,927	101,751	97,574	93,398	89,222	85,045	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		962	932	901	744	657	633	609	585	561	537	513	489	8,123
	b Debt Component (Line 6 x Debt Component x 1/12)		273	265	256	224	205	198	190	183	175	168	160	153	2,450
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	50,112
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,411	5,373	5,333	5,144	5,038	5,007	4,975	4,944	4,912	4,881	4,849	4,818	60,685
	a Recoverable Costs Allocated to Energy		5,411	5,373	5,333	5,144	5,038	5,007	4,975	4,944	4,912	4,881	4,849	4,818	60,685
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		5,219	5,196	5,164	4,989	4,907	4,878	4,835	4,798	4,771	4,734	4,687	4,658	58,836
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		5,219	5,196	5,164	4,989	4,907	4,878	4,835	4,798	4,771	4,734	4,687	4,658	58,836

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Applicable depreciation rate or rates.
(F) PE 1244 7 year amorization; PE 1006 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		1,482,025	1,909,176	8,274,631	4,640,105	1,708,359	989,313	1,097,155	4,846	913	0	0	0	
	b Clearings to Plant		0	0	0	23,827,424	1,708,359	989,313	1,097,155	4,846	913	0	0	0	
	c Retirements		0	0	0	0	6,236,000	0	0	0	0	0	0	0	
	d Cost of Removal		1,221,051	3,832,608	285,385	180,226	151,491	495,533	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	(50,000)	
2	Plant-in-Service/Depreciation Base (B)	13,909,529	13,909,529	13,909,529	13,909,529	37,736,953	33,209,312	34,198,625	35,295,780	35,300,626	35,301,539	35,301,539	35,301,539	35,301,539	
3	Less: Accumulated Depreciation (C)	(3,972,665)	(2,802,278)	979,667	1,214,389	1,343,952	7,611,275	7,999,848	7,890,001	7,776,954	7,663,893	7,550,830	7,437,766	7,374,703	
4	CWIP - Non Interest Bearing	7,521,487	9,003,512	10,912,688	19,187,320	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,458,351	20,110,763	25,801,884	34,311,238	39,080,905	40,820,587	42,198,473	43,185,781	43,077,580	42,965,432	42,852,369	42,739,305	42,676,242	
6	Average Net Investment		18,784,557	22,956,324	30,056,561	36,696,072	39,950,746	41,509,530	42,692,127	43,131,681	43,021,506	42,908,901	42,795,837	42,707,774	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		138,011	168,661	220,824	230,376	229,757	238,721	245,522	248,050	247,417	246,769	246,119	245,612	2,705,839
	b Debt Component (Line 6 x Debt Component x 1/12)		39,203	47,910	62,728	69,429	71,712	74,510	76,632	77,421	77,224	77,021	76,819	76,660	827,269
8	Investment Expenses														
	a Depreciation (E)		40,574	40,574	40,574	40,574	110,079	96,872	99,757	102,958	102,972	102,975	102,975	102,975	983,859
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	121,068
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		227,877	267,234	334,215	350,468	421,637	420,192	432,000	438,518	437,702	436,854	436,002	435,336	4,638,035
	a Recoverable Costs Allocated to Energy		227,877	267,234	334,215	350,468	421,637	420,192	432,000	438,518	437,702	436,854	436,002	435,336	4,638,035
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		219,787	258,409	323,647	339,891	410,693	409,370	419,818	425,566	425,094	423,713	421,448	420,860	4,498,296
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		219,787	258,409	323,647	339,891	410,693	409,370	419,818	425,566	425,094	423,713	421,448	420,860	4,498,296

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,459,714	1,459,501	1,459,288	1,459,075	1,458,862	1,458,649	1,458,436	1,458,223	1,458,010	1,457,797	1,457,584	1,457,371	1,457,158	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,459,714	1,459,501	1,459,288	1,459,075	1,458,862	1,458,649	1,458,436	1,458,223	1,458,010	1,457,797	1,457,584	1,457,371	1,457,158	
6	Average Net Investment		1,459,608	1,459,395	1,459,182	1,458,969	1,458,756	1,458,543	1,458,330	1,458,117	1,457,904	1,457,691	1,457,478	1,457,265	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,724	10,722	10,721	9,159	8,389	8,388	8,387	8,386	8,384	8,383	8,382	8,381	108,406
	b Debt Component (Line 6 x Debt Component x 1/12)		3,046	3,046	3,045	2,760	2,618	2,618	2,618	2,617	2,617	2,617	2,616	2,616	32,834
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		213	213	213	213	213	213	213	213	213	213	213	213	2,556
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		13,983	13,981	13,979	12,132	11,220	11,219	11,218	11,216	11,214	11,213	11,211	11,210	143,796
	a Recoverable Costs Allocated to Energy		13,983	13,981	13,979	12,132	11,220	11,219	11,218	11,216	11,214	11,213	11,211	11,210	143,796
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		13,487	13,519	13,537	11,766	10,929	10,930	10,902	10,885	10,891	10,876	10,837	10,837	139,396
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		13,487	13,519	13,537	11,766	10,929	10,930	10,902	10,885	10,891	10,876	10,837	10,837	139,396

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	
3	Less: Accumulated Depreciation (C)	5,384,847	5,358,309	5,331,770	5,305,231	5,278,693	5,252,154	5,225,615	5,199,077	5,172,538	5,146,000	5,119,461	5,092,922	5,066,384	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	14,482,771	14,456,233	14,429,694	14,403,155	14,376,617	14,350,078	14,323,539	14,297,001	14,270,462	14,243,924	14,217,385	14,190,846	14,164,308	
6	Average Net Investment		14,469,502	14,442,964	14,416,425	14,389,886	14,363,348	14,336,809	14,310,270	14,283,732	14,257,193	14,230,655	14,204,116	14,177,577	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		106,307	106,112	105,917	90,340	82,604	82,451	82,298	82,146	81,993	81,840	81,688	81,535	1,065,231
	b Debt Component (Line 6 x Debt Component x 1/12)		30,198	30,142	30,087	27,226	25,782	25,735	25,687	25,639	25,592	25,544	25,496	25,449	322,577
8	Investment Expenses														
	a Depreciation (E)		26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	318,468
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		163,044	162,793	162,543	144,105	134,925	134,725	134,524	134,324	134,124	133,923	133,723	133,523	1,706,276
	a Recoverable Costs Allocated to Energy		163,044	162,793	162,543	144,105	134,925	134,725	134,524	134,324	134,124	133,923	133,723	133,523	1,706,276
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		157,255	157,417	157,403	139,756	131,423	131,255	130,731	130,357	130,261	129,894	129,259	129,083	1,654,094
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		157,255	157,417	157,403	139,756	131,423	131,255	130,731	130,357	130,261	129,894	129,259	129,083	1,654,094

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1358, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 1592, 1658, 1829 & 1830
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		8,647	5,905	120,397	5,376	310	396	0	0	0	0	0	0	
	b Clearings to Plant		8,647	5,905	162	162,583	310	396	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	7,233,262	7,241,909	7,247,814	7,247,975	7,410,558	7,410,868	7,411,264	7,411,264	7,411,264	7,411,264	7,411,264	7,411,264	7,411,264	
3	Less: Accumulated Depreciation (C)	2,755,894	2,734,797	2,713,675	2,692,535	2,671,395	2,649,781	2,628,166	2,606,550	2,584,934	2,563,317	2,541,701	2,520,085	2,498,469	
4	CWIP - Non Interest Bearing	36,972	36,972	36,972	157,207	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	10,026,128	10,013,678	9,998,461	10,097,717	10,081,953	10,060,649	10,039,430	10,017,814	9,996,198	9,974,581	9,952,965	9,931,349	9,909,733	
6	Average Net Investment		10,019,903	10,006,070	10,048,089	10,089,835	10,071,301	10,050,040	10,028,622	10,007,006	9,985,390	9,963,773	9,942,157	9,920,541	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		73,617	73,514	73,822	63,341	57,920	57,798	57,675	57,550	57,426	57,302	57,177	57,053	744,195
	b Debt Component (Line 6 x Debt Component x 1/12)		20,912	20,883	20,970	19,090	18,078	18,040	18,001	17,963	17,924	17,885	17,846	17,807	225,399
8	Investment Expenses														
	a Depreciation (E)		20,869	20,894	20,912	20,912	21,386	21,387	21,388	21,388	21,388	21,388	21,388	21,388	254,688
	b Amortization (F)		228	228	228	228	228	228	228	228	228	228	228	228	2,736
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	14,652
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		116,847	116,740	117,153	104,792	98,833	98,674	98,513	98,350	98,187	98,024	97,860	97,697	1,241,670
	a Recoverable Costs Allocated to Energy		116,847	116,740	117,153	104,792	98,833	98,674	98,513	98,350	98,187	98,024	97,860	97,697	1,241,670
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		112,699	112,885	113,449	101,629	96,268	96,133	95,735	95,445	95,359	95,075	94,593	94,448	1,203,718
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		112,699	112,885	113,449	101,629	96,268	96,133	95,735	95,445	95,359	95,075	94,593	94,448	1,203,718

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist, $3,997,211; Scholz $916,802; Smith $1,734,877; Daniel $584,373. Ending Balances: Crist, $4,175,213; Scholz $916,802; Smith $1,734,877; Daniel $584,373.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Crist: 3.5%; Crist 1-3 CEMS 3.2%; Smith 3.3%; Scholz 4.1%; Daniel 2.8% annually
(F) Part of PE 1283 has a 7 year amortization period. PEs 1364 and 1658 have a 7 year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Sub. Contam. Mobile Groundwater Treat. Sys.
P.E.s 1007, 3400, 3412, & 2859
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	329,000	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	329,000	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	1,247,024	1,247,024	1,247,024	1,247,024	
3	Less: Accumulated Depreciation (C)	(263,753)	(265,435)	(267,118)	(268,801)	(270,484)	(272,166)	(273,849)	(275,532)	(277,215)	(278,897)	(281,128)	(283,360)	(285,591)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	654,271	652,589	650,906	649,223	647,540	645,858	644,175	642,492	640,809	968,127	965,896	963,664	961,433	
6	Average Net Investment		653,430	651,748	650,065	648,382	646,699	645,017	643,334	641,651	804,468	967,012	964,780	962,549	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,801	4,788	4,776	4,071	3,719	3,709	3,700	3,690	4,626	5,561	5,548	5,536	54,525
	b Debt Component (Line 6 x Debt Component x 1/12)		1,364	1,360	1,357	1,227	1,161	1,158	1,155	1,152	1,444	1,736	1,732	1,728	16,574
8	Investment Expenses														
	a Depreciation (E)		1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	2,231	2,231	2,231	21,840
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,848	7,831	7,816	6,981	6,563	6,550	6,538	6,525	7,753	9,528	9,511	9,495	92,939
	a Recoverable Costs Allocated to Energy		604	602	601	537	505	504	503	502	596	733	732	730	7,149
	b Recoverable Costs Allocated to Demand		7,244	7,229	7,215	6,444	6,058	6,046	6,035	6,023	7,157	8,795	8,779	8,765	85,790
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		583	582	582	521	492	491	489	487	579	711	708	706	6,931
13	Retail Demand-Related Recoverable Costs (I)		6,987	6,972	6,959	6,223	5,850	5,839	5,828	5,817	6,912	8,494	8,478	8,465	82,824
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,570	7,554	7,541	6,744	6,342	6,330	6,317	6,304	7,491	9,205	9,186	9,171	89,755

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Part of PE 1007 depreciable at 2.2% annually; PEs 3400 and 3412 are depreciable at 2.2% annually; PE 2859 depreciable at 2.0% annually.
(F) The amortizable portion of PE 1007 is fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E.s 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	
3	Less: Accumulated Depreciation (C)	(87,457)	(88,150)	(88,843)	(89,536)	(90,229)	(90,922)	(91,615)	(92,308)	(93,001)	(93,694)	(94,387)	(95,080)	(95,773)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	155,516	154,823	154,130	153,437	152,744	152,051	151,358	150,665	149,972	149,279	148,586	147,893	147,200	
6	Average Net Investment		155,170	154,477	153,784	153,091	152,398	151,705	151,012	150,319	149,626	148,933	148,240	147,547	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,140	1,135	1,130	961	876	872	868	864	860	857	853	849	11,265
	b Debt Component (Line 6 x Debt Component x 1/12)		324	322	321	290	274	272	271	270	269	267	266	265	3,411
8	Investment Expenses														
	a Depreciation (E)		693	693	693	693	693	693	693	693	693	693	693	693	8,316
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,157	2,150	2,144	1,944	1,843	1,837	1,832	1,827	1,822	1,817	1,812	1,807	22,992
	a Recoverable Costs Allocated to Energy		166	165	165	150	142	141	141	141	140	140	139	139	1,769
	b Recoverable Costs Allocated to Demand		1,991	1,985	1,979	1,794	1,701	1,696	1,691	1,686	1,682	1,677	1,673	1,668	21,223
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		160	160	160	145	138	137	137	137	136	136	134	134	1,714
13	Retail Demand-Related Recoverable Costs (I)		1,920	1,914	1,909	1,733	1,643	1,638	1,633	1,628	1,624	1,620	1,616	1,611	20,489
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,080	2,074	2,069	1,878	1,781	1,775	1,770	1,765	1,760	1,756	1,750	1,745	22,203

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist, $149,950; Smith $93,023.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Crist 3.5%; Smith 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	500,367	500,198	500,029	499,860	499,691	499,522	499,353	499,184	499,015	498,846	498,677	498,508	498,339	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	500,367	500,198	500,029	499,860	499,691	499,522	499,353	499,184	499,015	498,846	498,677	498,508	498,339	
6	Average Net Investment		500,283	500,114	499,945	499,776	499,607	499,438	499,269	499,100	498,931	498,762	498,593	498,424	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,676	3,674	3,673	3,138	2,873	2,872	2,871	2,870	2,869	2,868	2,867	2,866	37,117
	b Debt Component (Line 6 x Debt Component x 1/12)		1,044	1,044	1,043	946	897	896	896	896	896	895	895	895	11,243
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		169	169	169	169	169	169	169	169	169	169	169	169	2,028
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,889	4,887	4,885	4,253	3,939	3,937	3,936	3,935	3,934	3,932	3,931	3,930	50,388
	a Recoverable Costs Allocated to Energy		376	376	376	327	303	303	303	303	303	302	302	302	3,876
	b Recoverable Costs Allocated to Demand		4,513	4,511	4,509	3,926	3,636	3,634	3,633	3,632	3,631	3,630	3,629	3,628	46,512
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		363	364	364	317	295	295	294	294	294	293	292	292	3,757
13	Retail Demand-Related Recoverable Costs (I)		4,353	4,351	4,349	3,791	3,511	3,509	3,509	3,508	3,507	3,506	3,505	3,504	44,903
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,716	4,715	4,713	4,108	3,806	3,804	3,803	3,802	3,801	3,799	3,797	3,796	48,660

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Dechlorination System
P.E.s 1180, 1248
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		14,519	5,385	6,017	(228)	(48)	163	0	0	0	0	0	0	
	b Clearings to Plant		83,582	5,385	6,017	(228)	(48)	163	0	0	0	0	0	0	
	c Retirements		0	0	0	0	18,134	0	0	0	0	0	0	0	
	d Cost of Removal		1	5	24	(22)	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	305,323	388,905	394,290	400,307	400,079	381,897	382,060	382,060	382,060	382,060	382,060	382,060	382,060	
3	Less: Accumulated Depreciation (C)	(174,030)	(174,920)	(176,050)	(177,177)	(178,367)	(161,400)	(162,514)	(163,629)	(164,744)	(165,859)	(166,974)	(168,089)	(169,204)	
4	CWIP - Non Interest Bearing	69,063	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	200,356	213,985	218,240	223,130	221,712	220,497	219,546	218,431	217,316	216,201	215,086	213,971	212,856	
6	Average Net Investment		207,171	216,113	220,685	222,421	221,105	220,022	218,989	217,874	216,759	215,644	214,529	213,414	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,522	1,587	1,620	1,396	1,272	1,265	1,259	1,253	1,247	1,240	1,234	1,227	16,122
	b Debt Component (Line 6 x Debt Component x 1/12)		432	451	461	421	397	395	393	391	389	387	385	383	4,885
8	Investment Expenses														
	a Depreciation (E)		891	1,135	1,151	1,168	1,167	1,114	1,115	1,115	1,115	1,115	1,115	1,115	13,316
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,845	3,173	3,232	2,985	2,836	2,774	2,767	2,759	2,751	2,742	2,734	2,725	34,323
	a Recoverable Costs Allocated to Energy		219	244	249	230	218	213	213	212	212	211	210	210	2,641
	b Recoverable Costs Allocated to Demand		2,626	2,929	2,983	2,755	2,618	2,561	2,554	2,547	2,539	2,531	2,524	2,515	31,682
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		211	236	241	223	212	208	207	206	206	205	203	203	2,561
13	Retail Demand-Related Recoverable Costs (I)		2,533	2,825	2,877	2,661	2,528	2,473	2,466	2,460	2,452	2,444	2,438	2,429	30,586
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,744	3,061	3,118	2,884	2,740	2,681	2,673	2,666	2,658	2,649	2,641	2,632	33,147

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(33,655)	(33,856)	(34,057)	(34,258)	(34,459)	(34,660)	(34,861)	(35,062)	(35,263)	(35,464)	(35,665)	(35,866)	(36,067)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	35,268	35,067	34,866	34,665	34,464	34,263	34,062	33,861	33,660	33,459	33,258	33,057	32,856	
6	Average Net Investment		35,168	34,967	34,766	34,565	34,364	34,163	33,962	33,761	33,560	33,359	33,158	32,957	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		258	257	255	217	198	196	195	194	193	192	191	190	2,536
	b Debt Component (Line 6 x Debt Component x 1/12)		73	73	73	65	62	61	61	61	60	60	60	59	768
8	Investment Expenses														
	a Depreciation (E)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		532	531	529	483	461	458	457	456	454	453	452	450	5,716
	a Recoverable Costs Allocated to Energy		41	41	41	37	35	35	35	35	35	35	35	35	440
	b Recoverable Cost: Allocated to Demand		491	490	488	446	426	423	422	421	419	418	417	415	5,276
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		40	40	40	36	34	34	34	34	34	34	34	34	428
13	Retail Demand-Related Recoverable Costs (I)		474	473	471	431	411	409	408	407	405	404	403	401	5,097
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		514	513	511	467	445	443	442	441	439	438	437	435	5,525

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(58,773)	(59,069)	(59,365)	(59,661)	(59,957)	(60,253)	(60,549)	(60,845)	(61,141)	(61,437)	(61,733)	(62,029)	(62,325)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	42,722	42,426	42,130	41,834	41,538	41,242	40,946	40,650	40,354	40,058	39,762	39,466	39,170	
6	Average Net Investment		42,574	42,278	41,982	41,686	41,390	41,094	40,798	40,502	40,206	39,910	39,614	39,318	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		313	311	308	262	238	236	235	233	231	230	228	226	3,051
	b Debt Component (Line 6 x Debt Component x 1/12)		89	88	88	79	74	74	73	73	72	72	71	71	924
8	Investment Expenses														
	a Depreciation (E)		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		698	695	692	637	608	606	604	602	599	598	595	593	7,527
	a Recoverable Costs Allocated to Energy		54	53	53	49	47	47	46	46	46	46	46	46	579
	b Recoverable Costs Allocated to Demand		644	642	639	588	561	559	558	556	553	552	549	547	6,948
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		52	51	51	48	46	46	45	45	45	45	44	44	562
13	Retail Demand-Related Recoverable Costs (I)		621	619	616	568	542	540	539	537	534	533	530	528	6,707
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		673	670	667	616	588	586	584	582	579	578	574	572	7,269

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(34,798)	(34,972)	(35,146)	(35,320)	(35,494)	(35,668)	(35,842)	(36,016)	(36,190)	(36,364)	(36,538)	(36,712)	(36,886)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	24,745	24,571	24,397	24,223	24,049	23,875	23,701	23,527	23,353	23,179	23,005	22,831	22,657	
6	Average Net Investment		24,658	24,484	24,310	24,136	23,962	23,788	23,614	23,440	23,266	23,092	22,918	22,744	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		181	180	179	152	138	137	136	135	134	133	132	131	1,768
	b Debt Component (Line 6 x Debt Component x 1/12)		51	51	51	46	43	43	42	42	42	41	41	41	534
8	Investment Expenses														
	a Depreciation (E)		174	174	174	174	174	174	174	174	174	174	174	174	2,088
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		406	405	404	372	355	354	352	351	350	348	347	346	4,390
	a Recoverable Costs Allocated to Energy		31	31	31	29	27	27	27	27	27	27	27	27	338
	b Recoverable Costs Allocated to Demand		375	374	373	343	328	327	325	324	323	321	320	319	4,052
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		30	30	30	28	26	26	26	26	26	26	26	26	326
13	Retail Demand-Related Recoverable Costs (I)		362	361	360	331	317	316	314	313	312	310	309	308	3,913
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		392	391	390	359	343	342	340	339	338	336	335	334	4,239

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E.s 1214 & 1413
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(98,717)	(99,840)	(100,963)	(102,086)	(103,209)	(104,332)	(105,455)	(106,578)	(107,701)	(108,824)	(109,947)	(111,070)	(112,193)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	292,402	291,279	290,156	289,033	287,910	286,787	285,664	284,541	283,418	282,295	281,172	280,049	278,926	
6	Average Net Investment		291,841	290,718	289,595	288,472	287,349	286,226	285,103	283,980	282,857	281,734	280,611	279,488	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,144	2,136	2,128	1,811	1,653	1,646	1,640	1,633	1,627	1,620	1,614	1,607	21,259
	b Debt Component (Line 6 x Debt Component x 1/12)		609	607	604	546	516	514	512	510	508	506	504	502	6,438
8	Investment Expenses														
	a Depreciation (E)		1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	13,476
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,876	3,866	3,855	3,480	3,292	3,283	3,275	3,266	3,258	3,249	3,241	3,232	41,173
	a Recoverable Costs Allocated to Energy		3,876	3,866	3,855	3,480	3,292	3,283	3,275	3,266	3,258	3,249	3,241	3,232	41,173
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		3,738	3,738	3,733	3,375	3,207	3,198	3,183	3,170	3,164	3,151	3,133	3,125	39,915
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,738	3,738	3,733	3,375	3,207	3,198	3,183	3,170	3,164	3,151	3,133	3,125	39,915

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist, $284,622 and Smith $106,497.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Crist 3.5% annually; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	
3	Less: Accumulated Depreciation (C)	(1,396,276)	(1,403,928)	(1,411,580)	(1,419,232)	(1,426,884)	(1,434,536)	(1,442,188)	(1,449,840)	(1,457,492)	(1,465,144)	(1,472,796)	(1,480,448)	(1,488,100)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,386,324	1,378,672	1,371,020	1,363,368	1,355,716	1,348,064	1,340,412	1,332,760	1,325,108	1,317,456	1,309,804	1,302,152	1,294,500	
6	Average Net Investment		1,382,498	1,374,846	1,367,194	1,359,542	1,351,890	1,344,238	1,336,586	1,328,934	1,321,282	1,313,630	1,305,978	1,298,326	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,157	10,101	10,045	8,535	7,775	7,731	7,687	7,643	7,599	7,555	7,511	7,467	99,806
	b Debt Component (Line 6 x Debt Component x 1/12)		2,885	2,869	2,853	2,572	2,427	2,413	2,399	2,385	2,372	2,358	2,344	2,330	30,207
8	Investment Expenses														
	a Depreciation (E)		7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	91,824
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		20,694	20,622	20,550	18,759	17,854	17,796	17,738	17,680	17,623	17,565	17,507	17,449	221,837
	a Recoverable Costs Allocated to Energy		1,592	1,586	1,581	1,443	1,373	1,369	1,364	1,360	1,356	1,351	1,347	1,342	17,064
	b Recoverable Costs Allocated to Demand		19,102	19,036	18,969	17,316	16,481	16,427	16,374	16,320	16,267	16,214	16,160	16,107	204,773
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		1,535	1,534	1,531	1,399	1,337	1,334	1,326	1,320	1,317	1,310	1,302	1,297	16,542
13	Retail Demand-Related Recoverable Costs (I)		18,423	18,359	18,295	16,723	15,916	15,864	15,813	15,761	15,710	15,658	15,606	15,555	197,683
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		19,958	19,893	19,826	18,122	17,253	17,198	17,139	17,081	17,027	16,968	16,908	16,852	214,225

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E.s 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	83,718	83,226	82,734	82,242	81,750	81,258	80,766	80,274	79,782	79,290	78,798	78,306	77,814	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	262,680	262,188	261,696	261,204	260,712	260,220	259,728	259,236	258,744	258,252	257,760	257,268	256,776	
6	Average Net Investment		262,434	261,942	261,450	260,958	260,466	259,974	259,482	258,990	258,498	258,006	257,514	257,022	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,928	1,924	1,921	1,638	1,497	1,495	1,492	1,489	1,487	1,484	1,481	1,478	19,314
	b Debt Component (Line 6 x Debt Component x 1/12)		548	547	546	494	468	467	466	465	464	463	462	461	5,851
8	Investment Expenses														
	a Depreciation (E)		492	492	492	492	492	492	492	492	492	492	492	492	5,904
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,968	2,963	2,959	2,624	2,457	2,454	2,450	2,446	2,443	2,439	2,435	2,431	31,069
	a Recoverable Costs Allocated to Energy		228	228	228	202	189	189	188	188	188	188	187	187	2,390
	b Recoverable Costs Allocated to Demand		2,740	2,735	2,731	2,422	2,268	2,265	2,262	2,258	2,255	2,251	2,248	2,244	28,679
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		220	220	221	196	184	184	183	182	183	182	181	181	2,317
13	Retail Demand-Related Recoverable Costs (I)		2,643	2,638	2,634	2,339	2,190	2,187	2,184	2,181	2,178	2,174	2,171	2,167	27,686
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,863	2,858	2,855	2,535	2,374	2,371	2,367	2,363	2,361	2,356	2,352	2,348	30,003

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E.s 1501, 1535, 1555, & 1819
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	
3	Less: Accumulated Depreciation (C)	(5,168,807)	(5,212,682)	(5,256,557)	(5,300,432)	(5,344,307)	(5,388,182)	(5,432,057)	(5,475,932)	(5,519,807)	(5,563,682)	(5,607,557)	(5,651,432)	(5,695,307)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	9,781,317	9,737,442	9,693,567	9,649,692	9,605,817	9,561,942	9,518,067	9,474,192	9,430,317	9,386,442	9,342,567	9,298,692	9,254,817	
6	Average Net Investment		9,759,380	9,715,505	9,671,630	9,627,755	9,583,880	9,540,005	9,496,130	9,452,255	9,408,380	9,364,505	9,320,630	9,276,755	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		71,702	71,380	71,057	60,443	55,116	54,865	54,612	54,360	54,108	53,855	53,603	53,351	708,452
	b Debt Component (Line 6 x Debt Component x 1/12)		20,368	20,276	20,185	18,216	17,203	17,124	17,046	16,967	16,888	16,809	16,731	16,652	214,465
8	Investment Expenses														
	a Depreciation (E)		34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	418,548
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	107,952
	d Property Taxes		27,389	27,389	27,389	27,389	27,389	27,389	27,389	27,389	27,389	27,389	27,389	27,389	328,668
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		163,334	162,920	162,506	149,923	143,583	143,253	142,922	142,591	142,260	141,928	141,598	141,267	1,778,085
	a Recoverable Costs Allocated to Energy		12,564	12,532	12,500	11,533	11,045	11,019	10,994	10,969	10,943	10,918	10,892	10,867	136,776
	b Recoverable Costs Allocated to Demand		150,770	150,388	150,006	138,390	132,538	132,234	131,928	131,622	131,317	131,010	130,706	130,400	1,641,309
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		12,118	12,118	12,105	11,185	10,758	10,735	10,684	10,645	10,628	10,590	10,528	10,506	132,600
13	Retail Demand-Related Recoverable Costs (I)		145,411	145,043	144,675	133,648	127,997	127,703	127,407	127,112	126,817	126,521	126,227	125,932	1,584,493
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		157,529	157,161	156,780	144,833	138,755	138,438	138,091	137,757	137,445	137,111	136,755	136,438	1,717,093

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 2.8% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E.s 1601, 1620, 1638
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	
3	Less: Accumulated Depreciation (C)	(30,773)	(31,142)	(31,511)	(31,880)	(32,249)	(32,618)	(32,987)	(33,356)	(33,725)	(34,094)	(34,463)	(34,832)	(35,201)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	103,361	102,992	102,623	102,254	101,885	101,516	101,147	100,778	100,409	100,040	99,671	99,302	98,933	
6	Average Net Investment		103,177	102,808	102,439	102,070	101,701	101,332	100,963	100,594	100,225	99,856	99,487	99,118	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		758	755	753	641	584	583	581	579	576	574	572	570	7,526
	b Debt Component (Line 6 x Debt Component x 1/12)		215	215	214	193	183	182	181	181	180	179	179	178	2,280
8	Investment Expenses														
	a Depreciation (E)		369	369	369	369	369	369	369	369	369	369	369	369	4,428
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,342	1,339	1,336	1,203	1,136	1,134	1,131	1,129	1,125	1,122	1,120	1,117	14,234
	a Recoverable Costs Allocated to Energy		103	103	103	93	87	87	87	87	87	86	86	86	1,095
	b Recoverable Costs Allocated to Demand		1,239	1,236	1,233	1,110	1,049	1,047	1,044	1,042	1,038	1,036	1,034	1,031	13,139
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		99	100	100	90	85	85	85	84	84	83	83	83	1,061
13	Retail Demand-Related Recoverable Costs (I)		1,195	1,192	1,189	1,072	1,013	1,011	1,008	1,006	1,002	1,001	999	996	12,684
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,294	1,292	1,289	1,162	1,098	1,096	1,093	1,090	1,086	1,084	1,082	1,079	13,745

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Applicable depreciation rate or rates.
(F) PE 4397 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E.s 1031, 1158, 1167, 1199, 1250, 1287
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	(54,477)	(2,023)	3,927	54,363	42,880	147,200	658,171	201,000	216,000	223,000	178,666	
	b Clearings to Plant		0	(54,477)	119	(1)	0	0	0	0	0	620,005	12,000	1,113,666	
	c Retirements		0	0	0	0	0	0	0	687,931	0	0	0	2,121,481	
	d Cost of Removal		0	0	0	0	0	0	0	100,000	0	0	55,000	14,000	
	e Salvage		0	0	0	0	0	0	0	0	0	0	717,000	0	
2	Plant-in-Service/Depreciation Base (B)	124,400,004	124,400,004	124,345,527	124,345,646	124,345,645	124,345,645	124,345,645	124,345,645	123,657,714	123,657,714	124,277,719	124,289,719	123,281,904	
3	Less: Accumulated Depreciation (C)	(20,143,697)	(20,541,144)	(20,938,591)	(21,335,879)	(21,733,167)	(22,130,455)	(22,527,743)	(22,925,031)	(22,534,388)	(22,929,669)	(23,324,950)	(24,384,040)	(22,645,684)	
4	CWIP - Non Interest Bearing	22,605	22,605	22,605	20,463	24,391	78,754	121,634	268,834	927,005	1,128,005	724,000	935,000	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	104,278,912	103,881,465	103,429,541	103,030,230	102,636,869	102,293,944	101,939,536	101,689,448	102,050,331	101,856,050	101,676,769	100,840,679	100,636,220	
6	Average Net Investment		104,080,189	103,655,503	103,229,886	102,833,550	102,465,407	102,116,740	101,814,492	101,869,890	101,953,191	101,766,410	101,258,724	100,738,450	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		764,677	761,557	758,429	645,587	589,279	587,273	585,535	585,854	586,333	585,259	582,339	579,347	7,611,469
	b Debt Component (Line 6 x Debt Component x 1/12)		217,215	216,329	215,441	194,561	183,925	183,300	182,757	182,856	183,006	182,671	181,759	180,826	2,304,646
8	Investment Expenses														
	a Depreciation (E)		362,258	362,258	362,099	362,099	362,099	362,099	362,099	362,099	360,092	360,092	361,901	361,936	4,341,131
	b Amortization (F)		2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	30,228
	c Dismantlement		32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	392,040
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,379,339	1,375,333	1,371,158	1,237,436	1,170,492	1,167,861	1,165,580	1,165,998	1,164,620	1,163,211	1,161,188	1,157,298	14,679,514
	a Recoverable Costs Allocated to Energy		1,379,339	1,375,333	1,371,158	1,237,436	1,170,492	1,167,861	1,165,580	1,165,998	1,164,620	1,163,211	1,161,188	1,157,298	14,679,514
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		1,330,368	1,329,917	1,327,803	1,200,090	1,140,111	1,137,783	1,132,712	1,131,559	1,131,074	1,128,220	1,122,428	1,118,815	14,230,880
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,330,368	1,329,917	1,327,803	1,200,090	1,140,111	1,137,783	1,132,712	1,131,559	1,131,074	1,128,220	1,122,428	1,118,815	14,230,880

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually; Part of PEs 1158 and 1287 depreciable at 3.5% annually.
(F) Portions of PEs 1158 and 1287 have a 7-year amortization.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, and 1628
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	7,000	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	7,000	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	936,679	936,679	936,679	936,679	936,679	
3	Less: Accumulated Depreciation (C)	(154,622)	(157,332)	(160,042)	(162,752)	(165,462)	(168,172)	(170,882)	(173,592)	(176,302)	(179,031)	(181,760)	(184,489)	(187,218)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	775,057	772,347	769,637	766,927	764,217	761,507	758,797	756,087	760,377	757,648	754,919	752,190	749,461	
6	Average Net Investment		773,702	770,992	768,282	765,572	762,862	760,152	757,442	758,232	759,013	756,284	753,555	750,826	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,684	5,664	5,645	4,806	4,387	4,372	4,356	4,361	4,365	4,349	4,334	4,318	56,641
	b Debt Component (Line 6 x Debt Component x 1/12)		1,615	1,609	1,603	1,448	1,369	1,364	1,360	1,361	1,362	1,358	1,353	1,348	17,150
8	Investment Expenses														
	a Depreciation (E)		2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,729	2,729	2,729	2,729	32,596
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,009	9,983	9,958	8,964	8,466	8,446	8,426	8,432	8,456	8,436	8,416	8,395	106,387
	a Recoverable Costs Allocated to Energy		770	768	766	690	651	650	648	649	650	649	647	646	8,184
	b Recoverable Costs Allocated to Demand		9,239	9,215	9,192	8,274	7,815	7,796	7,778	7,783	7,806	7,787	7,769	7,749	98,203
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		743	743	742	669	634	633	630	630	631	629	625	625	7,934
13	Retail Demand-Related Recoverable Costs (I)		8,911	8,887	8,865	7,990	7,547	7,529	7,511	7,516	7,539	7,520	7,503	7,483	94,801
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		9,654	9,630	9,607	8,659	8,181	8,162	8,141	8,146	8,170	8,149	8,128	8,108	102,735

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist, $919,836; Smith $9,843; Ending Balances: Crist, $919,836; Smith $16,843.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Crist 3.5%; Smith 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(16,321)	(16,504)	(16,687)	(16,870)	(17,053)	(17,236)	(17,419)	(17,602)	(17,785)	(17,968)	(18,151)	(18,334)	(18,517)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	46,549	46,366	46,183	46,000	45,817	45,634	45,451	45,268	45,085	44,902	44,719	44,536	44,353	
6	Average Net Investment		46,458	46,275	46,092	45,909	45,726	45,543	45,360	45,177	44,994	44,811	44,628	44,445	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		341	340	339	288	263	262	261	260	259	258	257	256	3,384
	b Debt Component (Line 6 x Debt Component x 1/12)		97	97	96	87	82	82	81	81	81	80	80	80	1,024
8	Investment Expenses														
	a Depreciation (E)		183	183	183	183	183	183	183	183	183	183	183	183	2,196
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		621	620	618	558	528	527	525	524	523	521	520	519	6,604
	a Recoverable Costs Allocated to Energy		621	620	618	558	528	527	525	524	523	521	520	519	6,604
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		599	600	598	541	514	513	510	509	508	505	503	502	6,402
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		599	600	598	541	514	513	510	509	508	505	503	502	6,402

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330, 1461, 1462
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	
3	Less: Accumulated Depreciation (C)	(4,320,969)	(4,405,450)	(4,489,931)	(4,574,412)	(4,658,893)	(4,743,374)	(4,827,855)	(4,912,336)	(4,996,817)	(5,081,298)	(5,165,779)	(5,250,260)	(5,334,741)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	25,518,709	25,434,228	25,349,747	25,265,266	25,180,785	25,096,304	25,011,823	24,927,342	24,842,861	24,758,380	24,673,899	24,589,418	24,504,937	
6	Average Net Investment		25,476,469	25,391,988	25,307,507	25,223,026	25,138,545	25,054,064	24,969,583	24,885,102	24,800,621	24,716,140	24,631,659	24,547,178	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		187,176	186,555	185,934	158,350	144,572	144,086	143,600	143,114	142,628	142,143	141,657	141,171	1,860,986
	b Debt Component (Line 6 x Debt Component x 1/12)		53,169	52,993	52,817	47,722	45,124	44,972	44,820	44,669	44,517	44,365	44,214	44,062	563,444
8	Investment Expenses														
	a Depreciation (E)		84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	1,013,772
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		324,826	324,029	323,232	290,553	274,177	273,539	272,901	272,264	271,626	270,989	270,352	269,714	3,438,202
	a Recoverable Costs Allocated to Energy		324,826	324,029	323,232	290,553	274,177	273,539	272,901	272,264	271,626	270,989	270,352	269,714	3,438,202
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		313,294	313,329	313,012	281,784	267,061	266,494	265,205	264,222	263,802	262,837	261,328	260,745	3,333,113
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		313,294	313,329	313,012	281,784	267,061	266,494	265,205	264,222	263,802	262,837	261,328	260,745	3,333,113

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balancesand Ending Balances: Crist $13,997,696; Smith $15,715,201; Scholz $126,781.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Crist 3.5%; Smith 3.3%; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E.s 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.s 1178, 1227, 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		54,687	75,782	33,852	7,381	19,906	4,434	30,000	0	0	0	0	0	
	b Clearings to Plant		7,780	378	276	(210)	(24)	373,927	30,000	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	19,637,297	19,645,077	19,645,455	19,645,731	19,645,521	19,645,497	20,019,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	
3	Less: Accumulated Depreciation (C)	(1,195,671)	(1,252,953)	(1,310,258)	(1,367,564)	(1,424,871)	(1,482,177)	(1,539,483)	(1,597,880)	(1,656,364)	(1,714,848)	(1,773,332)	(1,831,816)	(1,890,300)	
4	CWIP - Non Interest Bearing	186,085	232,992	308,396	341,972	349,563	369,493	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	18,627,711	18,625,116	18,643,593	18,620,139	18,570,213	18,532,813	18,479,941	18,451,544	18,393,060	18,334,576	18,276,092	18,217,608	18,159,124	
6	Average Net Investment		18,626,414	18,634,355	18,631,866	18,595,176	18,551,513	18,506,377	18,465,743	18,422,302	18,363,818	18,305,334	18,246,850	18,188,366	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		136,848	136,905	136,887	116,741	106,689	106,430	106,196	105,947	105,610	105,274	104,938	104,601	1,373,066
	b Debt Component (Line 6 x Debt Component x 1/12)		38,873	38,890	38,885	35,182	33,300	33,219	33,146	33,068	32,963	32,858	32,753	32,648	415,785
8	Investment Expenses														
	a Depreciation (E)		57,282	57,305	57,306	57,307	57,306	57,306	58,397	58,484	58,484	58,484	58,484	58,484	694,629
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		233,003	233,100	233,078	209,230	197,295	196,955	197,739	197,499	197,057	196,616	196,175	195,733	2,483,480
	a Recoverable Costs Allocated to Energy		17,923	17,931	17,929	16,095	15,177	15,150	15,211	15,192	15,158	15,124	15,090	15,056	191,036
	b Recoverable Costs Allocated to Demand		215,080	215,169	215,149	193,135	182,118	181,805	182,528	182,307	181,899	181,492	181,085	180,677	2,292,444
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		17,287	17,339	17,362	15,609	14,783	14,760	14,782	14,743	14,721	14,669	14,586	14,555	185,196
13	Retail Demand-Related Recoverable Costs (I)		207,436	207,522	207,502	186,517	175,878	175,575	176,274	176,060	175,666	175,273	174,880	174,486	2,213,069
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		224,723	224,861	224,864	202,126	190,661	190,335	191,056	190,803	190,387	189,942	189,466	189,041	2,398,265

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E.s 1204 & 1299
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		43,580	37,013	6,607	285	37	1,293	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	135,353	1,293	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	6,018,040	6,018,040	6,018,040	6,018,040	6,018,040	6,153,393	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	
3	Less: Accumulated Depreciation (C)	(1,109,012)	(1,126,567)	(1,144,122)	(1,161,677)	(1,179,232)	(1,196,787)	(1,214,736)	(1,232,689)	(1,250,642)	(1,268,595)	(1,286,548)	(1,304,501)	(1,322,454)	
4	CWIP - Non Interest Bearing	47,831	91,411	128,424	135,031	135,316	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	4,956,859	4,982,884	5,002,342	4,991,394	4,974,124	4,956,606	4,939,950	4,921,997	4,904,044	4,886,091	4,868,138	4,850,185	4,832,232	
6	Average Net Investment		4,969,872	4,992,613	4,996,868	4,982,759	4,965,365	4,948,278	4,930,974	4,913,021	4,895,068	4,877,115	4,859,162	4,841,209	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		36,514	36,680	36,711	31,282	28,555	28,458	28,358	28,255	28,152	28,048	27,945	27,842	366,800
	b Debt Component (Line 6 x Debt Component x 1/12)		10,372	10,420	10,428	9,427	8,913	8,882	8,851	8,819	8,787	8,754	8,722	8,690	111,065
8	Investment Expenses														
	a Depreciation (E)		17,555	17,555	17,555	17,555	17,555	17,949	17,953	17,953	17,953	17,953	17,953	17,953	213,442
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		64,441	64,655	64,694	58,264	55,023	55,289	55,162	55,027	54,892	54,755	54,620	54,485	691,307
	a Recoverable Costs Allocated to Energy		4,957	4,973	4,976	4,482	4,233	4,253	4,243	4,233	4,222	4,212	4,202	4,191	53,177
	b Recoverable Costs Allocated to Demand		59,484	59,682	59,718	53,782	50,790	51,036	50,919	50,794	50,670	50,543	50,418	50,294	638,130
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		4,781	4,809	4,819	4,347	4,123	4,143	4,123	4,108	4,100	4,085	4,062	4,052	51,552
13	Retail Demand-Related Recoverable Costs (I)		57,370	57,561	57,596	51,939	49,050	49,287	49,174	49,054	48,934	48,811	48,690	48,571	616,037
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		62,151	62,370	62,415	56,286	53,173	53,430	53,297	53,162	53,034	52,896	52,752	52,623	667,589

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1222, 1233, 1279, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1810, 1824, & 1826
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		70,916	66,274	47,934	149,745,615	8,787,243	2,907,046	3,095,842	2,262,361	4,093,241	1,369,400	796,651	629,923	
	b Clearings to Plant		69,569	62,618	46,458	149,744,664	8,794,675	2,905,411	3,097,475	2,262,361	4,093,241	1,369,400	796,651	629,923	
	c Retirements		0	269,096	121,718	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	(940,793)	21,541	39,921	81,737	5,451	0	0	0	0	0	0	
	e Salvage		7,220	2,187	16,522	0	(33,549)	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	625,142,855	625,212,424	625,005,946	624,930,686	774,675,350	783,470,025	786,375,436	789,472,911	791,735,272	795,828,513	797,197,913	797,994,564	798,624,487	
3	Less: Accumulated Depreciation (C)	(53,266,652)	(55,411,995)	(58,224,205)	(60,235,058)	(62,332,507)	(64,791,387)	(67,385,756)	(69,994,051)	(72,611,382)	(75,235,312)	(77,871,182)	(80,511,047)	(83,153,235)	
4	CWIP - Non Interest Bearing	0	1,347	5,003	6,479	7,430	(2)	1,633	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	571,876,203	569,801,776	566,786,744	564,702,107	712,350,273	718,678,636	718,991,313	719,478,860	719,123,890	720,593,201	719,326,731	717,483,517	715,471,252	
6	Average Net Investment		570,838,990	568,294,260	565,744,426	638,526,190	715,514,455	718,834,975	719,235,087	719,301,375	719,858,546	719,959,966	718,405,124	716,477,385	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,193,954	4,175,258	4,156,523	4,008,667	4,114,924	4,134,020	4,136,321	4,136,702	4,139,906	4,140,490	4,131,548	4,120,461	49,588,774
	b Debt Component (Line 6 x Debt Component x 1/12)		1,191,341	1,186,030	1,180,709	1,208,092	1,284,348	1,290,309	1,291,027	1,291,146	1,292,146	1,292,328	1,289,537	1,286,077	15,083,090
8	Investment Expenses														
	a Depreciation (E)		1,810,459	1,810,662	1,809,926	1,809,706	2,246,502	2,272,156	2,280,631	2,289,667	2,296,266	2,308,206	2,312,201	2,314,524	25,560,906
	b Amortization (F)		12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	153,204
	c Dismantlement		314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	3,778,764
	d Property Taxes		84,152	84,152	84,152	84,152	84,152	84,152	84,152	84,152	84,152	84,152	84,152	84,152	1,009,824
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,607,570	7,583,766	7,558,974	7,438,281	8,057,590	8,108,301	8,119,795	8,129,331	8,140,134	8,152,840	8,145,102	8,132,878	95,174,562
	a Recoverable Costs Allocated to Energy		7,607,570	7,583,766	7,558,974	7,438,281	8,057,590	8,108,301	8,119,795	8,129,331	8,140,134	8,152,840	8,145,102	8,132,878	95,174,562
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		7,337,477	7,333,334	7,319,962	7,213,794	7,848,452	7,899,476	7,890,824	7,889,222	7,905,661	7,907,590	7,873,222	7,862,439	92,281,453
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,337,477	7,333,334	7,319,962	7,213,794	7,848,452	7,899,476	7,890,824	7,889,222	7,905,661	7,907,590	7,873,222	7,862,439	92,281,453

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable
(B) Beginning Balances: Crist $604,794,044; Smith $12,931,385; Daniel $6,773,206, Scholz $644,221. Ending Balances: Crist $778,545,848; Smith $12,931,385; Daniel $6,772,129, Scholz $375,125.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Crist: 3.5%, Smith 3.3%, Smith CT 3.6%, Daniel 2.8%, Scholz 4.1%. Portion of PE 1222 is transmission: 2.0%, 2.3%, 3.6%, and 2.5%.
(F) Portions of PE 1222 and 1233 have a 7 year amortization period. PE 1279 amortization period begins in 2013.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.1280
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	
3	Less: Accumulated Depreciation (C)	(22,270)	(22,804)	(23,338)	(23,872)	(24,406)	(24,940)	(25,474)	(26,008)	(26,542)	(27,076)	(27,610)	(28,144)	(28,678)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	9,751	9,217	8,683	8,149	7,615	7,081	6,547	6,013	5,479	4,945	4,411	3,877	3,343	
6	Average Net Investment		9,484	8,950	8,416	7,882	7,348	6,814	6,280	5,746	5,212	4,678	4,144	3,610	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		70	66	62	49	42	39	36	33	30	27	24	21	499
	b Debt Component (Line 6 x Debt Component x 1/12)		20	19	18	15	13	12	11	10	9	8	7	6	148
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		534	534	534	534	534	534	534	534	534	534	534	534	6,408
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		624	619	614	598	589	585	581	577	573	569	565	561	7,055
	a Recoverable Costs Allocated to Energy		48	48	47	46	45	45	45	44	44	44	43	43	542
	b Recoverable Costs Allocated to Demand		576	571	567	552	544	540	536	533	529	525	522	518	6,513
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (J)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		46	46	46	45	44	44	44	43	43	43	42	42	528
13	Retail Demand-Related Recoverable Costs (I)		556	551	547	533	525	521	518	515	511	507	504	500	6,288
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		602	597	593	578	569	565	562	558	554	550	546	542	6,816

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(E) Applicable depreciation rate or rates.
(F) 5 year amortization beginning 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(I) Line 9b x Line 11.
(J) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Mercury Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (F)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(B) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E
(F) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Working Capital, Annual NOx Expenses
For Project: Annual NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	1,675,143	1,631,294	1,596,828	1,545,818	1,470,604	1,380,996	1,316,805	1,239,405	1,162,904	1,103,210	1,047,956	1,002,427	953,131	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	1,675,143	1,631,294	1,596,828	1,545,818	1,470,604	1,380,996	1,316,805	1,239,405	1,162,904	1,103,210	1,047,956	1,002,427	953,131	
4	Average Net Working Capital Balance		1,653,219	1,614,061	1,571,323	1,508,211	1,425,800	1,348,901	1,278,105	1,201,155	1,133,057	1,075,583	1,025,192	977,779	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		12,146	11,859	11,545	9,469	8,200	7,758	7,350	6,908	6,516	6,186	5,896	5,623	99,456
	b Debt Component (Line 4 x Debt Component x 1/12)		3,450	3,369	3,279	2,854	2,559	2,421	2,294	2,156	2,034	1,931	1,840	1,755	29,942
6	Total Return Component (D)		15,596	15,228	14,824	12,323	10,759	10,179	9,644	9,064	8,550	8,117	7,736	7,378	129,398
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual Nox Allowance Expense		43,849	34,466	51,010	75,214	89,608	64,191	77,400	76,501	59,694	55,254	45,529	49,296	722,012
8	Net Expenses (E)		43,849	34,466	51,010	75,214	89,608	64,191	77,400	76,501	59,694	55,254	45,529	49,296	722,012
9	Total System Recoverable Expenses (Lines 6 + 8)		59,445	49,694	65,834	87,537	100,367	74,370	87,044	85,565	68,244	63,371	53,265	56,674	851,410
	a Recoverable Costs Allocated to Energy		59,445	49,694	65,834	87,537	100,367	74,370	87,044	85,565	68,244	63,371	53,265	56,674	851,410
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (F)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (B)		57,335	48,053	63,752	84,895	97,762	72,455	84,589	83,038	66,278	61,465	51,487	54,789	825,898
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		57,335	48,053	63,752	84,895	97,762	72,455	84,589	83,038	66,278	61,465	51,487	54,789	825,898

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(B) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E
(F) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	24	24	24	24	24	19	15	11	8	4	4	4	4	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	24	24	24	24	24	19	15	11	8	4	4	4	4	
4	Average Net Working Capital Balance		24	24	24	24	22	17	13	10	6	4	4	4	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		0	0	0	0	5	4	4	4	3	0	0	0	20
8	Net Expenses (E)		0	0	0	0	5	4	4	4	3	0	0	0	20
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	5	4	4	4	3	0	0	0	20
	a Recoverable Costs Allocated to Energy		0	0	0	0	5	4	4	4	3	0	0	0	20
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (F)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	4	4	4	4	3	0	0	0	19
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	4	4	4	4	3	0	0	0	19

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(B) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E
(F) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2012 - December 2012

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	711	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	8,657,438	8,621,251	8,603,109	8,554,015	8,492,890	8,436,641	8,389,480	8,271,549	8,150,591	8,056,681	7,978,965	7,909,618	7,841,670	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(798,054)	(776,038)	(754,022)	(731,946)	(710,581)	(688,505)	(666,429)	(644,353)	(622,277)	(600,201)	(578,125)	(556,049)	(533,973)	
3	Total Working Capital Balance	7,859,384	7,845,213	7,849,087	7,822,069	7,782,309	7,748,136	7,723,051	7,627,196	7,528,314	7,456,480	7,400,840	7,353,569	7,307,697	
4	Average Net Working Capital Balance		7,852,299	7,847,150	7,835,578	7,802,189	7,765,223	7,735,594	7,675,124	7,577,755	7,492,397	7,428,660	7,377,205	7,330,633	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		57,691	57,653	57,568	48,982	44,658	44,487	44,140	43,580	43,089	42,722	42,426	42,158	569,154
	b Debt Component (Line 4 x Debt Component x 1/12)		16,388	16,377	16,353	14,762	13,939	13,885	13,777	13,602	13,449	13,334	13,242	13,158	172,266
6	Total Return Component (D)		74,079	74,030	73,921	63,744	58,597	58,372	57,917	57,182	56,538	56,056	55,668	55,316	741,420
7	Expenses														
	a Gains		(22,016)	(22,016)	(22,076)	(22,076)	(22,076)	(22,076)	(22,076)	(22,076)	(22,076)	(22,076)	(22,076)	(22,076)	(264,792)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		36,187	18,142	49,094	61,125	56,249	47,161	117,931	120,958	93,910	77,716	69,347	67,948	815,768
8	Net Expenses (E)		14,171	(3,874)	27,018	39,049	34,173	25,085	95,855	98,882	71,834	55,640	47,271	45,872	550,976
9	Total System Recoverable Expenses (Lines 6 + 8)		88,250	70,156	100,939	102,793	92,770	83,457	153,772	156,064	128,372	111,696	102,939	101,188	1,292,396
	a Recoverable Costs Allocated to Energy		88,250	70,156	100,939	102,793	92,770	83,457	153,772	156,064	128,372	111,696	102,939	101,188	1,292,396
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9638222	0.9663015	0.9677030	0.9683675	0.9725857	0.9727864	0.9703454	0.9690104	0.9697408	0.9684657	0.9651727	0.9652995	
11	Demand Jurisdictional Factor (F)		0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (B)		85,117	67,839	97,747	99,691	90,362	81,308	149,436	151,454	124,674	108,336	99,503	97,823	1,253,290
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		85,117	67,839	97,747	99,691	90,362	81,308	149,436	151,454	124,674	108,336	99,503	97,823	1,253,290

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 12% January 1-April 10, 2012 and 10.25% for April 11-December 31, 2012. See Schedule 9E.
(B) Line 9a x Line 10 x 1.0007 line loss multiplier for January-March 2012 and Line 9a x Line 10 x 1.0015 line loss multiplier for April-December 2012.
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E
(F) The Demand Jurisdictional factor was 0.9644582 from January-March 2012 and 0.9657346 from April-December 2012 as a result of Rate Case Docket No. 110138-EI.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual True-Up Amount
January 1, 2012 - April 10, 2012

FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Column:
(1) Capital Structure Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual True-Up Amount
April 11, 2012 - December 31, 2012

FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	657,374	39.2874	5.26	2.0665	2.0665	
2	Short-Term Debt	17,925	1.0713	0.13	0.0014	0.0014	
3	Preferred Stock	72,957	4.3602	6.39	0.2786	0.4536	
4	Common Stock	644,159	38.4976	10.25	3.9460	6.4241	
5	Customer Deposits	21,229	1.2687	6.00	0.0761	0.0761	
6	Deferred Taxes	256,675	15.3400				
7	Investment Tax Credit	2,924	0.1748	7.66	0.0134	0.0191	
8	Total	1,673,243	100.0000		6.3820	9.0408	0.7534
	ITC Component:						
9	Debt	657,374	47.8268	5.26	2.5157	0.0044	
10	Equity-Preferred	72,957	5.3079	6.39	0.3392	0.0010	
11	-Common	644,159	46.8653	10.25	4.8037	0.0137	
12		1,374,490	100.0000		7.6586	0.0191	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.1484	0.1790
14	Total Equity Component (Lines 3, 4, 10, and 11)					6.8924	0.5744
15	Total Revenue Requirement Rate of Return					9.0408	0.7534

Column:
(1) Capital Structure Approved by FPSC on February 27, 2012 in Docket No. 110138-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on February 27, 2012 in Docket No. 110138-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120007-EI EXHIBIT 37
PARTY Gulf Power Company
DESCRIPTION R.W. Dodd (RWD-3), Calculation Projection)
DATE 1/13-12/13.

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2013 - December 2013

Line No.		Energy ($)	Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period			
	a Projected O & M Activities (Schedule 2P, Lines 7, 8 & 9)	20,069,669	3,881,584	23,951,253
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	112,534,635	4,573,191	117,107,826
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	132,604,304	8,454,775	141,059,079
2	True-Up for Estimated Over/(Under) Recovery for the period January 2012 - December 2012 (Schedule 1E, Line 3)	7,001,685	451,674	7,453,359
3	Final True-Up for the period January 2011 - December 2011 (Schedule 1A, Line 3)	(4,951,708)	(323,924)	(5,275,632)
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2013 - December 2013 (Line 1c - Line 2 - Line 3)	130,554,327	8,327,025	138,881,352
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	130,648,326	8,333,020	138,981,347

Notes:

Allocation to energy and demand in each period are in proportion to the respective period split of costs indicated on Lines 7 & 8 of Schedules 5E & 7E and 5A & 7A.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)

January 2013 - December 2013
Calculation of the Current Period True-Up Amount
Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	4,770	4,739	4,709	4,678	4,647	4,616	4,586	4,555	4,525	4,493	4,463	4,432	55,213	0	55,213
	.2 Crist 5, 6 & 7 Precipitator Projects	416,012	415,254	414,498	413,742	412,986	412,230	411,473	410,717	409,961	409,205	408,448	407,692	4,942,218	0	4,942,218
	.3 Crist 7 Flue Gas Conditioning	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	128,424	0	128,424
	.4 Low NOx Burners, Crist 6 & 7	130,464	130,270	130,074	129,880	129,684	129,490	129,294	129,100	128,905	128,710	128,515	128,320	1,552,706	0	1,552,706
	.5 CEMS - Plants Crist, Scholz, Smith, & Daniel	95,361	95,204	95,045	94,888	94,731	94,572	94,415	94,256	94,099	93,941	93,783	93,626	1,133,921	0	1,133,921
	.6 Substation Contamination Remediation	9,834	10,846	11,858	12,943	13,845	14,284	15,641	15,616	15,590	15,564	15,538	15,513	167,072	154,222	12,850
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	1,772	1,766	1,761	1,756	1,751	1,747	1,741	1,736	1,731	1,726	1,720	1,715	20,922	19,313	1,609
	.8 Crist Cooling Tower Cell	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	43,920	40,536	3,384
	.9 Crist Dechlorination System	2,674	2,666	2,658	2,650	2,642	2,633	2,625	2,617	2,609	2,601	2,592	2,584	31,551	29,124	2,427
	.10 Crist Diesel Fuel Oil Remediation	442	440	439	438	435	434	432	431	430	428	427	426	5,202	4,802	400
	.11 Crist Bulk Tanker Unload Sec Contain Struc	583	580	578	576	574	572	570	567	566	563	561	559	6,849	6,322	527
	.12 Crist IWW Sampling System	339	338	337	335	335	334	333	331	330	329	327	326	3,994	3,687	307
	.13 Sodium Injection System	3,167	3,159	3,151	3,143	3,134	3,126	3,118	3,110	3,101	3,093	3,085	3,077	37,464	0	37,464
	.14 Smith Stormwater Collection System	17,131	17,074	17,019	16,962	16,906	16,850	16,794	16,737	16,682	16,625	16,569	16,512	201,861	186,334	15,527
	.15 Smith Waste Water Treatment Facility	2,376	2,372	2,369	2,365	2,361	2,358	2,355	2,351	2,347	2,343	2,340	2,336	28,273	26,098	2,175
	.16 Daniel Ash Management Project	128,717	128,460	128,204	127,947	127,692	127,436	127,179	126,923	126,667	126,411	126,155	125,898	1,527,689	1,410,175	117,514
	.17 Smith Water Conservation	1,095	1,092	1,088	1,086	1,083	1,080	1,078	1,075	1,072	1,070	26,404	51,739	88,962	82,119	6,843
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist FDEP Agreement for Ozone Attainment	1,099,260	1,096,605	1,093,950	1,091,295	1,088,640	1,085,985	1,083,330	1,080,676	1,078,020	1,075,365	1,072,710	1,070,056	13,015,892	0	13,015,892
	.20 SPCC Compliance	8,223	8,203	8,183	8,163	8,143	8,123	8,103	8,083	8,062	8,042	8,023	8,003	97,354	89,865	7,489
	.21 Crist Common FTIR Monitor	508	507	506	504	503	502	500	499	498	496	495	494	6,012	0	6,012
	.22 Precipitator Upgrades for CAM Compliance	264,135	263,515	262,894	262,273	261,653	261,033	260,413	259,792	259,172	258,552	257,930	257,310	3,128,672	0	3,128,672
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	191,629	191,201	190,771	190,341	189,912	189,482	189,053	188,623	188,193	187,765	187,335	186,905	2,271,210	2,096,501	174,709
	.25 NPDES Permit Compliance Projects	53,375	53,243	53,112	52,979	52,847	52,716	52,584	52,452	52,320	52,189	52,057	51,925	631,799	583,198	48,601
	.26 CAIR/CAMR/CAVR Compliance	7,678,897	7,661,791	7,644,686	7,627,581	7,610,475	7,593,371	7,576,266	7,559,160	7,542,055	7,524,950	7,508,457	7,492,576	91,020,265	0	91,020,265
	.27 General Water Quality	557	553	549	545	541	537	139	0	0	0	0	0	3,421	3,157	264
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual NOx Allowances	6,905	6,712	6,501	6,253	6,001	5,755	5,455	5,105	4,786	4,541	4,336	4,102	66,452	0	66,452
	.30 Seasonal NOx Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.31 SO2 Allowances	53,548	53,313	53,018	52,628	52,267	51,929	51,454	50,866	50,370	50,041	49,777	49,445	618,656	0	618,656
2	Total Investment Projects - Recoverable Costs	10,186,136	10,164,265	10,142,320	10,120,313	10,098,150	10,075,557	10,053,293	10,029,740	10,006,453	9,983,405	9,986,409	9,989,933	120,835,974	4,735,453	116,100,521
3	Recoverable Costs Allocated to Energy	9,796,223	9,774,272	9,752,240	9,730,088	9,707,940	9,685,792	9,663,491	9,640,938	9,618,522	9,596,344	9,576,831	9,557,840	116,100,521		
4	Recoverable Costs Allocated to Demand	389,913	389,993	390,080	390,225	390,210	389,765	389,802	388,802	387,931	387,061	409,578	432,093	4,735,453		
5	Retail Energy Jurisdictional Factor	0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016			
6	Retail Demand Jurisdictional Factor	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346			
7	Jurisdictional Energy Recoverable Costs (B)	9,480,430	9,460,896	9,434,662	9,433,958	9,418,713	9,415,998	9,389,914	9,355,358	9,340,793	9,306,997	9,256,888	9,240,038	112,534,635		
8	Jurisdictional Demand Recoverable Costs (C)	376,552	376,630	376,714	376,854	376,839	376,410	376,445	375,480	374,638	373,798	395,544	417,287	4,573,191		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	9,856,972	9,837,526	9,811,376	9,810,812	9,795,552	9,792,408	9,766,359	9,730,838	9,715,431	9,680,795	9,652,432	9,657,325	117,107,826		

Notes:

(A) Pages 1-27 of Schedule 4P, Line 9, Pages 28-31 of Schedule 4P, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	
3	Less: Accumulated Depreciation (C)	(267,855)	(272,031)	(276,208)	(280,384)	(284,560)	(288,737)	(292,913)	(297,089)	(301,266)	(305,442)	(309,618)	(313,795)	(317,971)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	82,957	78,781	74,604	70,428	66,252	62,075	57,899	53,723	49,546	45,370	41,194	37,017	32,841	
6	Average Net Investment		80,869	76,693	72,516	68,340	64,164	59,987	55,811	51,635	47,458	43,282	39,106	34,929	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		449	426	403	380	356	333	310	287	264	240	217	194	3,859
	b Debt Component (Line 6 x Debt Component x 1/12)		145	137	130	122	115	107	100	92	85	77	70	62	1,242
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	50,112
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,770	4,739	4,709	4,678	4,647	4,616	4,586	4,555	4,525	4,493	4,463	4,432	55,213
	a Recoverable Costs Allocated to Energy		4,770	4,739	4,709	4,678	4,647	4,616	4,586	4,555	4,525	4,493	4,463	4,432	55,213
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		4,616	4,587	4,556	4,536	4,509	4,487	4,456	4,420	4,394	4,358	4,314	4,285	53,518
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,616	4,587	4,556	4,536	4,509	4,487	4,456	4,420	4,394	4,358	4,314	4,285	53,518

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1006 is fully amortized; PE 1244 has a 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Schedule 7P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2013 - December 2013

Rate Class	(1) Percentage of KWH Sales at Generation (%)	(2) Percentage of 12 CP Demand at Generation (%)	(3) Energy-Related Costs	(4) Demand-Related Costs	(5) Total Environmental Costs	(6) Projected Sales at Meter (KWH)	(7) Environmental Cost Recovery Factors (¢/KWH)
RS, RSVP	48.55616%	57.25855%	63,437,809	4,771,365	68,209,175	5,445,580,000	1.253
GS	2.51996%	2.69411%	3,292,286	224,501	3,516,787	282,614,000	1.244
GSD, GSDT, GSTOU	23.69672%	21.66942%	30,959,368	1,805,717	32,765,085	2,657,985,000	1.233
LP, LPT	10.10202%	8.03822%	13,198,120	669,827	13,867,947	1,160,741,000	1.195
PX, PXT, RTP, SBS	13.74907%	9.70138%	17,962,930	808,418	18,771,348	1,607,910,000	1.167
OS-I, OS-II	0.96811%	0.36650%	1,264,820	30,541	1,295,361	108,574,000	1.193
OS-III	0.40796%	0.27182%	532,993	22,651	555,644	45,752,000	1.214
TOTAL	100.00000%	100.00000%	$130,648,326	$8,333,020	138,981,347	11,309,156,000	1.229

Notes:
(1) From Schedule 6P, Col 8
(2) From Schedule 6P, Col 9
(3) Col 1 x Total Energy $ from Schedule 1P, line 5
(4) Col 2 x Total Demand $ from Schedule 1P, line 5
(5) Col 3 + Col 4
(6) Projected KWH sales for the period January 2013 - December 2013
(7) Col 5 x 100 / Col 6

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2013 - December 2013

Line No.		Energy ($)	Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period			
	a Projected O & M Activities (Schedule 2P, Lines 7, 8 & 9)	20,069,669	3,881,584	23,951,253
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	112,557,519	4,573,191	117,130,710
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	132,627,188	8,454,775	141,081,963
2	True-Up for Estimated Over/(Under) Recovery for the period January 2012 - December 2012 (Schedule 1E, Line 3)	7,001,685	451,674	7,453,359
3	Final True-Up for the period January 2011 - December 2011 (Schedule 1A, Line 3)	(4,951,708)	(323,924)	(5,275,632)
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2013 - December 2013 (Line 1c - Line 2 - Line 3)	130,577,211	8,327,025	138,904,236
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	130,671,227	8,333,020	139,004,247

Notes:

Allocation to energy and demand in each period are in proportion to the respective period split of costs indicated on Lines 7 & 8 of Schedules 5E & 7E and 5A & 7A.

Schedule 2P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013

O & M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
	.1 Sulfur	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.2 Air Emission Fees	-	492,000	-	-	-	-	-	-	-	-	140,000	-	632,000	0	632,000
	.3 Title V	8,575	9,575	9,031	11,131	13,247	9,031	9,831	10,131	9,831	10,831	13,247	10,581	125,044	0	125,044
	.4 Asbestos Fees	-	-	-	-	-	-	-	-	-	900	-	-	900	900	0
	.5 Emission Monitoring	57,054	42,054	42,682	71,682	70,506	45,682	54,682	52,682	48,682	43,182	70,506	46,182	645,576	0	645,576
	.6 General Water Quality	49,645	57,750	75,578	57,378	95,138	66,466	51,353	67,078	81,021	68,923	90,728	90,895	851,953	851,953	0
	.7 Groundwater Contamination Investigation	117,921	117,921	119,129	169,129	199,801	119,129	282,464	283,264	233,264	183,264	203,138	132,470	2,160,894	2,160,894	0
	.8 State NPDES Administration	-	-	-	-	-	-	-	-	-	-	-	34,500	34,500	34,500	0
	.9 Lead and Copper Rule	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,377	16,480	16,480	0
	.10 Env Auditing/Assessment	-	-	-	-	-	-	-	-	-	3,500	3,500	-	7,000	7,000	0
	.11 General Solid & Hazardous Waste	34,000	35,637	38,720	37,920	45,830	39,220	41,220	37,720	38,720	36,120	44,130	39,920	469,157	469,157	0
	.12 Above Ground Storage Tanks	1,055	31,055	23,970	770	23,356	44,470	3,170	4,570	26,370	3,070	1,356	23,370	186,582	186,582	0
	.13 Low NOx	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	10,833	1,500	10,833	1,500	10,833	1,500	10,833	1,500	10,833	1,500	10,835	1,500	74,000	0	74,000
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.19 FDEP NOx Reduction Agreement	123,831	123,212	117,259	141,663	164,055	164,391	157,391	158,391	134,767	149,435	120,103	115,828	1,670,326	0	1,670,326
	.20 CAIR/CAMR/CAVR Compliance Program	1,153,093	1,081,934	1,304,319	1,336,176	1,420,283	1,589,090	1,574,273	1,516,735	1,322,004	1,234,926	1,267,890	1,741,841	16,542,564	0	16,542,564
	.21 MACT ICR	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.22 Crist Water Conservation	22,400	22,400	22,400	22,400	22,400	28,160	28,160	28,160	28,160	22,400	22,400	22,400	291,840	291,840	0
	.23 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.24 Annual NOx Allowances	25,920	26,589	30,920	36,460	32,130	34,964	46,841	48,433	38,498	27,895	27,958	35,696	412,304	0	412,304
	.25 Seasonal NOx Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.26 SO2 Allowances	32,432	31,647	48,736	57,600	40,677	51,484	77,581	82,623	52,434	37,268	34,685	55,720	602,887	0	602,887
2	Total of O & M Activities	1,638,132	2,074,647	1,844,950	1,945,182	2,139,629	2,194,960	2,339,172	2,292,660	2,025,957	1,824,587	2,051,849	2,352,280	24,724,007	4,019,306	20,704,701
3	Recoverable Costs Allocated to Energy	1,411,738	1,808,511	1,563,780	1,656,212	1,751,731	1,896,142	1,931,432	1,870,495	1,617,049	1,505,037	1,685,224	2,007,348	20,704,701		
4	Recoverable Costs Allocated to Demand	226,394	266,136	281,170	288,970	387,898	298,818	407,740	422,165	408,908	319,550	366,625	344,932	4,019,306		
5	Retail Energy Jurisdictional Factor	0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016			
6	Retail Demand Jurisdictional Factor	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346			
7	Jurisdictional Energy Recoverable Costs (A)	1,366,227	1,750,528	1,512,856	1,605,806	1,699,542	1,843,326	1,876,753	1,815,088	1,570,358	1,459,658	1,628,924	1,940,603	20,069,669		
8	Jurisdictional Demand Recoverable Costs (B)	218,637	257,017	271,536	279,068	374,607	288,579	393,769	407,699	394,897	308,600	354,062	333,113	3,881,584		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,584,864	2,007,545	1,784,392	1,884,874	2,074,149	2,131,905	2,270,522	2,222,787	1,965,255	1,768,258	1,982,986	2,273,716	23,951,253		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)

January 2013 - December 2013
Calculation of the Current Period True-Up Amount
Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	6,737	6,706	6,676	6,645	6,614	6,584	6,553	6,523	6,492	6,461	6,430	6,400	78,821	0	78,821
	.2 Crist 5, 6 & 7 Precipitator Projects	416,012	415,254	414,498	413,742	412,986	412,230	411,473	410,717	409,961	409,205	408,448	407,692	4,942,218	0	4,942,218
	.3 Crist 7 Flue Gas Conditioning	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	128,424	0	128,424
	.4 Low NOx Burners, Crist 6 & 7	130,464	130,270	130,074	129,880	129,684	129,490	129,294	129,100	128,905	128,710	128,515	128,320	1,552,706	0	1,552,706
	.5 CEMS - Plants Crist, Scholz, Smith, & Daniel	95,361	95,204	95,045	94,888	94,731	94,572	94,415	94,256	94,099	93,941	93,783	93,626	1,133,921	0	1,133,921
	.6 Substation Contamination Remediation	9,834	10,846	11,858	12,943	13,845	14,284	15,641	15,616	15,590	15,564	15,538	15,513	167,072	154,222	12,850
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	1,772	1,766	1,761	1,756	1,751	1,747	1,741	1,736	1,731	1,726	1,720	1,715	20,922	19,313	1,609
	.8 Crist Cooling Tower Cell	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	43,920	40,536	3,384
	.9 Crist Dechlorination System	2,674	2,666	2,658	2,650	2,642	2,633	2,625	2,617	2,609	2,601	2,592	2,584	31,551	29,124	2,427
	.10 Crist Diesel Fuel Oil Remediation	442	440	439	438	435	434	432	431	430	428	427	426	5,202	4,802	400
	.11 Crist Bulk Tanker Unload Sec Contain Struc	583	580	578	576	574	572	570	567	566	563	561	559	6,849	6,322	527
	.12 Crist IWW Sampling System	339	338	337	335	335	334	333	331	330	329	327	326	3,994	3,687	307
	.13 Sodium Injection System	3,167	3,159	3,151	3,143	3,134	3,126	3,118	3,110	3,101	3,093	3,085	3,077	37,464	0	37,464
	.14 Smith Stormwater Collection System	17,131	17,074	17,019	16,962	16,906	16,850	16,794	16,737	16,682	16,625	16,569	16,512	201,861	186,334	15,527
	.15 Smith Waste Water Treatment Facility	2,376	2,372	2,369	2,365	2,361	2,358	2,355	2,351	2,347	2,343	2,340	2,336	28,273	26,098	2,175
	.16 Daniel Ash Management Project	128,717	128,460	128,204	127,947	127,692	127,436	127,179	126,923	126,667	126,411	126,155	125,898	1,527,689	1,410,175	117,514
	.17 Smith Water Conservation	1,095	1,092	1,088	1,086	1,083	1,080	1,078	1,075	1,072	1,070	26,404	51,739	88,962	82,119	6,843
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist FDEP Agreement for Ozone Attainment	1,099,260	1,096,605	1,093,950	1,091,295	1,088,640	1,085,985	1,083,330	1,080,676	1,078,020	1,075,365	1,072,710	1,070,056	13,015,892	0	13,015,892
	.20 SPCC Compliance	8,223	8,203	8,183	8,163	8,143	8,123	8,103	8,083	8,062	8,042	8,023	8,003	97,354	89,865	7,489
	.21 Crist Common FTIR Monitor	508	507	506	504	503	502	500	499	498	496	495	494	6,012	0	6,012
	.22 Precipitator Upgrades for CAM Compliance	264,135	263,515	262,894	262,273	261,653	261,033	260,413	259,792	259,172	258,552	257,930	257,310	3,128,672	0	3,128,672
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	191,629	191,201	190,771	190,341	189,912	189,482	189,053	188,623	188,193	187,765	187,335	186,905	2,271,210	2,096,501	174,709
	.25 NPDES Permit Compliance Projects	53,375	53,243	53,112	52,979	52,847	52,716	52,584	52,452	52,320	52,189	52,057	51,925	631,799	583,198	48,601
	.26 CAIR/CAMR/CAVR Compliance	7,678,897	7,661,791	7,644,686	7,627,581	7,610,475	7,593,371	7,576,266	7,559,160	7,542,055	7,524,950	7,508,457	7,492,576	91,020,265	0	91,020,265
	.27 General Water Quality	557	553	549	545	541	537	139	0	0	0	0	0	3,421	3,157	264
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual NOx Allowances	6,905	6,712	6,501	6,253	6,001	5,755	5,455	5,105	4,786	4,541	4,336	4,102	66,452	0	66,452
	.30 Seasonal NOx Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.31 SO2 Allowances	53,548	53,313	53,018	52,628	52,267	51,929	51,454	50,866	50,370	50,041	49,777	49,445	618,656	0	618,656
2	Total Investment Projects - Recoverable Costs	10,188,103	10,166,232	10,144,287	10,122,280	10,100,117	10,077,525	10,055,260	10,031,708	10,008,420	9,985,373	9,988,376	9,991,901	120,859,582	4,735,453	116,124,129
3	Recoverable Costs Allocated to Energy	9,798,190	9,776,239	9,754,207	9,732,055	9,709,907	9,687,760	9,665,458	9,642,906	9,620,489	9,598,312	9,578,798	9,559,808	116,124,129		
4	Recoverable Costs Allocated to Demand	389,913	389,993	390,080	390,225	390,210	389,765	389,802	388,802	387,931	387,061	409,578	432,093	4,735,453		
5	Retail Energy Jurisdictional Factor	0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016			
6	Retail Demand Jurisdictional Factor	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346			
7	Jurisdictional Energy Recoverable Costs (B)	9,482,323	9,462,800	9,436,565	9,435,865	9,420,621	9,417,912	9,391,826	9,357,268	9,342,703	9,308,906	9,258,790	9,241,940	112,557,519		
8	Jurisdictional Demand Recoverable Costs (C)	376,552	376,630	376,714	376,854	376,839	376,410	376,445	375,480	374,638	373,798	395,544	417,287	4,573,191		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	9,858,875	9,839,430	9,813,279	9,812,719	9,797,460	9,794,322	9,768,271	9,732,748	9,717,341	9,682,704	9,654,334	9,659,227	117,130,710		

Notes:

(A) Pages 1-27 of Schedule 4P, Line 9, Pages 28-31 of Schedule 4P, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	e Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	
3	Less: Accumulated Depreciation (C)	0	(4,176)	(8,353)	(12,529)	(16,705)	(20,882)	(25,058)	(29,234)	(33,411)	(37,587)	(41,763)	(45,940)	(50,116)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	350,812	346,636	342,459	338,283	334,107	329,930	325,754	321,578	317,401	313,225	309,049	304,872	300,696	
6	Average Net Investment		348,724	344,548	340,371	336,195	332,019	327,842	323,666	319,490	315,313	311,137	306,961	302,784	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,937	1,914	1,891	1,868	1,844	1,821	1,798	1,775	1,752	1,728	1,705	1,682	21,715
	b Debt Component (Line 6 x Debt Component x 1/12)		624	616	609	601	594	587	579	572	564	557	549	542	6,994
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	50,112
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		6,737	6,706	6,676	6,645	6,614	6,584	6,553	6,523	6,492	6,461	6,430	6,400	78,821
	a Recoverable Costs Allocated to Energy		6,737	6,706	6,676	6,645	6,614	6,584	6,553	6,523	6,492	6,461	6,430	6,400	78,821
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		6,520	6,491	6,459	6,443	6,417	6,401	6,367	6,330	6,305	6,266	6,215	6,187	76,401
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,520	6,491	6,459	6,443	6,417	6,401	6,367	6,330	6,305	6,266	6,215	6,187	76,401

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1006 is fully amortized; PE 1244 has a 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	35,301,539	
3	Less: Accumulated Depreciation (C)	7,374,703	7,271,728	7,168,753	7,065,779	6,962,804	6,859,830	6,756,855	6,653,881	6,550,906	6,447,931	6,344,957	6,241,982	6,139,008	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	42,676,242	42,573,267	42,470,292	42,367,318	42,264,343	42,161,369	42,058,394	41,955,420	41,852,445	41,749,470	41,646,496	41,543,521	41,440,547	
6	Average Net Investment		42,624,755	42,521,780	42,418,805	42,315,831	42,212,856	42,109,882	42,006,907	41,903,933	41,800,958	41,697,983	41,595,009	41,492,034	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		236,781	236,208	235,636	235,064	234,492	233,920	233,348	232,776	232,204	231,632	231,060	230,488	2,803,609
	b Debt Component (Line 6 x Debt Component x 1/12)		76,256	76,071	75,887	75,703	75,519	75,335	75,150	74,966	74,782	74,598	74,413	74,229	902,909
8	Investment Expenses														
	a Depreciation (E)		102,975	102,975	102,975	102,975	102,975	102,975	102,975	102,975	102,975	102,975	102,975	102,975	1,235,700
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		416,012	415,254	414,498	413,742	412,986	412,230	411,473	410,717	409,961	409,205	408,448	407,692	4,942,218
	a Recoverable Costs Allocated to Energy		416,012	415,254	414,498	413,742	412,986	412,230	411,473	410,717	409,961	409,205	408,448	407,692	4,942,218
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		402,601	401,940	401,000	401,150	400,682	400,748	399,824	398,551	398,124	396,867	394,803	394,136	4,790,426
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		402,601	401,940	401,000	401,150	400,682	400,748	399,824	398,551	398,124	396,867	394,803	394,136	4,790,426

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	
6	Average Net Investment		1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	1,457,158	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	97,140
	b Debt Component (Line 6 x Debt Component x 1/12)		2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	31,284
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	128,424
	a Recoverable Costs Allocated to Energy		10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	10,702	128,424
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		10,357	10,359	10,353	10,376	10,383	10,404	10,399	10,385	10,393	10,379	10,344	10,346	124,478
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,357	10,359	10,353	10,376	10,383	10,404	10,399	10,385	10,393	10,379	10,344	10,346	124,478

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	
3	Less: Accumulated Depreciation (C)	5,066,384	5,039,845	5,013,306	4,986,768	4,960,229	4,933,690	4,907,152	4,880,613	4,854,074	4,827,536	4,800,997	4,774,458	4,747,920	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	14,164,308	14,137,769	14,111,230	14,084,692	14,058,153	14,031,614	14,005,076	13,978,537	13,951,998	13,925,460	13,898,921	13,872,382	13,845,844	
6	Average Net Investment		14,151,039	14,124,500	14,097,961	14,071,423	14,044,884	14,018,345	13,991,807	13,965,268	13,938,729	13,912,191	13,885,652	13,859,113	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		78,609	78,462	78,314	78,167	78,019	77,872	77,724	77,577	77,430	77,282	77,135	76,987	933,578
	b Debt Component (Line 6 x Debt Component x 1/12)		25,316	25,269	25,221	25,174	25,126	25,079	25,031	24,984	24,936	24,889	24,841	24,794	300,660
8	Investment Expenses														
	a Depreciation (E)		26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	318,468
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		130,464	130,270	130,074	129,880	129,684	129,490	129,294	129,100	128,905	128,710	128,515	128,320	1,552,706
	a Recoverable Costs Allocated to Energy		130,464	130,270	130,074	129,880	129,684	129,490	129,294	129,100	128,905	128,710	128,515	128,320	1,552,706
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		126,258	126,093	125,838	125,927	125,820	125,883	125,634	125,276	125,183	124,829	124,222	124,053	1,505,016
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		126,258	126,093	125,838	125,927	125,820	125,883	125,634	125,276	125,183	124,829	124,222	124,053	1,505,016

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1001, 1060, 1154, 1164, 1188, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1358, 1364, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 1558, 1570, 1592, 1658, 1829 & 1830
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	7,411,265	
3	Less: Accumulated Depreciation (C)	2,498,469	2,476,984	2,455,500	2,434,016	2,412,532	2,391,048	2,369,564	2,348,080	2,326,595	2,305,111	2,283,627	2,262,143	2,240,659	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	9,909,734	9,888,249	9,866,765	9,845,281	9,823,797	9,802,313	9,780,829	9,759,345	9,737,860	9,716,376	9,694,892	9,673,408	9,651,924	
6	Average Net Investment		9,898,992	9,877,507	9,856,023	9,834,539	9,813,055	9,791,571	9,770,087	9,748,603	9,727,118	9,705,634	9,684,150	9,662,666	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		54,989	54,870	54,750	54,631	54,512	54,392	54,273	54,153	54,034	53,915	53,795	53,676	651,990
	b Debt Component (Line 6 x Debt Component x 1/12)		17,709	17,671	17,632	17,594	17,556	17,517	17,479	17,440	17,402	17,363	17,325	17,287	209,975
8	Investment Expenses														
	a Depreciation (E)		21,388	21,388	21,388	21,388	21,388	21,388	21,388	21,388	21,388	21,388	21,388	21,388	256,656
	b Amortization (F)		96	96	96	96	96	96	96	96	96	96	96	96	1,152
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	14,148
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		95,361	95,204	95,045	94,888	94,731	94,572	94,415	94,256	94,099	93,941	93,783	93,626	1,133,921
	a Recoverable Costs Allocated to Energy		95,361	95,204	95,045	94,888	94,731	94,572	94,415	94,256	94,099	93,941	93,783	93,626	1,133,921
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		92,287	92,152	91,950	92,000	91,909	91,938	91,742	91,464	91,382	91,109	90,650	90,513	1,099,096
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		92,287	92,152	91,950	92,000	91,909	91,938	91,742	91,464	91,382	91,109	90,650	90,513	1,099,096

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances and Ending Balances: Crist, $4,175,213; Scholz $916,802 Smith $1,734,877; Daniel $584,373.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Crist 3.5%; Crist 1-3 CEMS 3.2%; Smith 3.3%; Scholz 4.1%; Daniel 2.8% annually.
(F) Part of PE 1283 has a 7 year amortization period. PEs 1364 & 1658 are fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Substation Contamination Remediation
P.E.s 1007, 2859, 3400, 3412, & 3477
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		150,000	130,000	150,000	150,000	100,000	24,000	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	704,000	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	1,247,024	1,247,024	1,247,024	1,247,024	1,247,024	1,247,024	1,951,024	1,951,024	1,951,024	1,951,024	1,951,024	1,951,024	1,951,024	
3	Less: Accumulated Depreciation (C)	(285,591)	(287,822)	(290,053)	(292,284)	(294,515)	(296,746)	(298,977)	(302,499)	(306,021)	(309,543)	(313,065)	(316,587)	(320,109)	
4	CWIP - Non Interest Bearing	0	150,000	280,000	430,000	580,000	680,000	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	961,433	1,109,202	1,236,971	1,384,740	1,532,509	1,630,278	1,652,047	1,648,525	1,645,003	1,641,481	1,637,959	1,634,437	1,630,915	
6	Average Net Investment		1,035,318	1,173,087	1,310,856	1,458,625	1,581,394	1,641,163	1,650,286	1,646,764	1,643,242	1,639,720	1,636,198	1,632,676	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,751	6,516	7,282	8,103	8,785	9,117	9,167	9,148	9,128	9,109	9,089	9,070	100,265
	b Debt Component (Line 6 x Debt Component x 1/12)		1,852	2,099	2,345	2,609	2,829	2,936	2,952	2,946	2,940	2,933	2,927	2,921	32,289
8	Investment Expenses														
	a Depreciation (E)		2,231	2,231	2,231	2,231	2,231	2,231	3,522	3,522	3,522	3,522	3,522	3,522	34,518
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		9,834	10,846	11,858	12,943	13,845	14,284	15,641	15,616	15,590	15,564	15,538	15,513	167,072
	a Recoverable Costs Allocated to Energy		756	834	912	996	1,065	1,099	1,203	1,201	1,199	1,197	1,195	1,193	12,850
	b Recoverable Costs Allocated to Demand		9,078	10,012	10,946	11,947	12,780	13,185	14,438	14,415	14,391	14,367	14,343	14,320	154,222
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		732	807	882	966	1,033	1,068	1,169	1,165	1,164	1,161	1,155	1,153	12,455
13	Retail Demand-Related Recoverable Costs (I)		8,767	9,669	10,571	11,538	12,342	12,733	13,943	13,921	13,898	13,875	13,852	13,829	148,938
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		9,499	10,476	11,453	12,504	13,375	13,801	15,112	15,086	15,062	15,036	15,007	14,982	161,393

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Part of PE 1007 depreciable at 2.2% annually; PEs 3400 and 3412 are depreciable at 2.2% annually; PE 2859 depreciable at 2.0% annually.
(F) The amortizable portion of PE 1007 is fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E.s 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	
3	Less: Accumulated Depreciation (C)	(95,773)	(96,466)	(97,159)	(97,852)	(98,545)	(99,238)	(99,931)	(100,624)	(101,317)	(102,010)	(102,703)	(103,396)	(104,089)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	147,200	146,507	145,814	145,121	144,428	143,735	143,042	142,349	141,656	140,963	140,270	139,577	138,884	
6	Average Net Investment		146,854	146,161	145,468	144,775	144,082	143,389	142,696	142,003	141,310	140,617	139,924	139,231	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		816	812	808	804	800	797	793	789	785	781	777	773	9,535
	b Debt Component (Line 6 x Debt Component x 1/12)		263	261	260	259	258	257	255	254	253	252	250	249	3,071
8	Investment Expenses														
	a Depreciation (E)		693	693	693	693	693	693	693	693	693	693	693	693	8,316
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,772	1,766	1,761	1,756	1,751	1,747	1,741	1,736	1,731	1,726	1,720	1,715	20,922
	a Recoverable Costs Allocated to Energy		136	136	135	135	135	134	134	134	133	133	132	132	1,609
	b Recoverable Costs Allocated to Demand		1,636	1,630	1,626	1,621	1,616	1,613	1,607	1,602	1,598	1,593	1,588	1,583	19,313
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		132	132	131	131	131	130	130	130	129	129	128	128	1,561
13	Retail Demand-Related Recoverable Costs (I)		1,580	1,574	1,570	1,565	1,561	1,558	1,552	1,547	1,543	1,538	1,534	1,529	18,651
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,712	1,706	1,701	1,696	1,692	1,688	1,682	1,677	1,672	1,667	1,662	1,657	20,212

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist, $149,950; Smith $93,023.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Crist 3.5%; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	
6	Average Net Investment		498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	498,339	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,768	2,768	2,768	2,768	2,768	2,768	2,768	2,768	2,768	2,768	2,768	2,768	33,216
	b Debt Component (Line 6 x Debt Component x 1/12)		892	892	892	892	892	892	892	892	892	892	892	892	10,704
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	3,660	43,920
	a Recoverable Costs Allocated to Energy		282	282	282	282	282	282	282	282	282	282	282	282	3,384
	b Recoverable Costs Allocated to Demand		3,378	3,378	3,378	3,378	3,378	3,378	3,378	3,378	3,378	3,378	3,378	3,378	40,536
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		273	273	273	273	274	274	274	274	274	273	273	273	3,281
13	Retail Demand-Related Recoverable Costs (I)		3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	39,144
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,535	3,535	3,535	3,535	3,536	3,536	3,536	3,536	3,536	3,535	3,535	3,535	42,425

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Dechlorination System
P.E.s 1180 & 1248
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	382,060	382,060	382,060	382,060	382,060	382,060	382,060	382,060	382,060	382,060	382,060	382,060	382,060	
3	Less: Accumulated Depreciation (C)	(169,204)	(170,319)	(171,434)	(172,549)	(173,664)	(174,779)	(175,894)	(177,009)	(178,124)	(179,239)	(180,354)	(181,469)	(182,584)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	212,856	211,741	210,626	209,511	208,396	207,281	206,166	205,051	203,936	202,821	201,706	200,591	199,476	
6	Average Net Investment		212,299	211,184	210,069	208,954	207,839	206,724	205,609	204,494	203,379	202,264	201,149	200,034	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,179	1,173	1,167	1,161	1,155	1,148	1,142	1,136	1,130	1,124	1,117	1,111	13,743
	b Debt Component (Line 6 x Debt Component x 1/12)		380	378	376	374	372	370	368	366	364	362	360	358	4,428
8	Investment Expenses														
	a Depreciation (E)		1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	13,380
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,674	2,666	2,658	2,650	2,642	2,633	2,625	2,617	2,609	2,601	2,592	2,584	31,551
	a Recoverable Costs Allocated to Energy		206	205	204	204	203	203	202	201	201	200	199	199	2,427
	b Recoverable Costs Allocated to Demand		2,468	2,461	2,454	2,446	2,439	2,430	2,423	2,416	2,408	2,401	2,393	2,385	29,124
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		199	198	197	198	197	197	196	195	195	194	192	192	2,350
13	Retail Demand-Related Recoverable Costs (I)		2,383	2,377	2,370	2,362	2,355	2,347	2,340	2,333	2,325	2,319	2,311	2,303	28,125
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,582	2,575	2,567	2,560	2,552	2,544	2,536	2,528	2,520	2,513	2,503	2,495	30,475

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(36,067)	(36,268)	(36,469)	(36,670)	(36,871)	(37,072)	(37,273)	(37,474)	(37,675)	(37,876)	(38,077)	(38,278)	(38,479)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	32,856	32,655	32,454	32,253	32,052	31,851	31,650	31,449	31,248	31,047	30,846	30,645	30,444	
6	Average Net Investment		32,756	32,555	32,354	32,153	31,952	31,751	31,550	31,349	31,148	30,947	30,746	30,545	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		182	181	180	179	177	176	175	174	173	172	171	170	2,110
	b Debt Component (Line 6 x Debt Component x 1/12)		59	58	58	58	57	57	56	56	56	55	55	55	680
8	Investment Expenses														
	a Depreciation (E)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		442	440	439	438	435	434	432	431	430	428	427	426	5,202
	a Recoverable Costs Allocated to Energy		34	34	34	34	33	33	33	33	33	33	33	33	400
	b Recoverable Costs Allocated to Demand		408	406	405	404	402	401	399	398	397	395	394	393	4,802
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		33	33	33	33	32	32	32	32	32	32	32	32	388
13	Retail Demand-Related Recoverable Costs (I)		394	392	391	390	388	387	385	384	383	381	380	380	4,635
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		427	425	424	423	420	419	417	416	415	413	412	412	5,023

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(62,325)	(62,621)	(62,917)	(63,213)	(63,509)	(63,805)	(64,101)	(64,397)	(64,693)	(64,989)	(65,285)	(65,581)	(65,877)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	39,170	38,874	38,578	38,282	37,986	37,690	37,394	37,098	36,802	36,506	36,210	35,914	35,618	
6	Average Net Investment		39,022	38,726	38,430	38,134	37,838	37,542	37,246	36,950	36,654	36,358	36,062	35,766	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		217	215	213	212	210	209	207	205	204	202	200	199	2,493
	b Debt Component (Line 6 x Debt Component x 1/12)		70	69	69	68	68	67	67	66	66	65	65	64	804
8	Investment Expenses														
	a Depreciation (E)		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		583	580	578	576	574	572	570	567	566	563	561	559	6,849
	a Recoverable Costs Allocated to Energy		45	45	44	44	44	44	44	44	44	43	43	43	527
	b Recoverable Costs Allocated to Demand		538	535	534	532	530	528	526	523	522	520	518	516	6,322
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		44	44	43	43	43	43	43	43	43	42	42	42	515
13	Retail Demand-Related Recoverable Costs (I)		520	517	516	514	512	510	508	505	504	502	500	498	6,106
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		564	561	559	557	555	553	551	548	547	544	542	540	6,621

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(36,886)	(37,060)	(37,234)	(37,408)	(37,582)	(37,756)	(37,930)	(38,104)	(38,278)	(38,452)	(38,626)	(38,800)	(38,974)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	22,657	22,483	22,309	22,135	21,961	21,787	21,613	21,439	21,265	21,091	20,917	20,743	20,569	
6	Average Net Investment		22,570	22,396	22,222	22,048	21,874	21,700	21,526	21,352	21,178	21,004	20,830	20,656	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		125	124	123	122	122	121	120	119	118	117	116	115	1,442
	b Debt Component (Line 6 x Debt Component x 1/12)		40	40	40	39	39	39	39	38	38	38	37	37	464
8	Investment Expenses														
	a Depreciation (E)		174	174	174	174	174	174	174	174	174	174	174	174	2,088
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		339	338	337	335	335	334	333	331	330	329	327	326	3,994
	a Recoverable Costs Allocated to Energy		26	26	26	26	26	26	26	25	25	25	25	25	307
	b Recoverable Costs Allocated to Demand		313	312	311	309	309	308	307	306	305	304	302	301	3,687
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		25	25	25	25	25	25	25	24	24	24	24	24	295
13	Retail Demand-Related Recoverable Costs (I)		302	301	300	298	298	297	296	296	295	294	292	291	3,560
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		327	326	325	323	323	322	321	320	319	318	316	315	3,855

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E.s 1214 & 1413
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(112,193)	(113,316)	(114,439)	(115,562)	(116,685)	(117,808)	(118,931)	(120,054)	(121,177)	(122,300)	(123,423)	(124,546)	(125,669)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	278,926	277,803	276,680	275,557	274,434	273,311	272,188	271,065	269,942	268,819	267,696	266,573	265,450	
6	Average Net Investment		278,365	277,242	276,119	274,996	273,873	272,750	271,627	270,504	269,381	268,258	267,135	266,012	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,546	1,540	1,534	1,528	1,521	1,515	1,509	1,503	1,496	1,490	1,484	1,478	18,144
	b Debt Component (Line 6 x Debt Component x 1/12)		498	496	494	492	490	488	486	484	482	480	478	476	5,844
8	Investment Expenses														
	a Depreciation (E)		1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	13,476
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,167	3,159	3,151	3,143	3,134	3,126	3,118	3,110	3,101	3,093	3,085	3,077	37,464
	a Recoverable Costs Allocated to Energy		3,167	3,159	3,151	3,143	3,134	3,126	3,118	3,110	3,101	3,093	3,085	3,077	37,464
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		3,065	3,058	3,048	3,047	3,041	3,039	3,030	3,018	3,011	3,000	2,982	2,975	36,314
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,065	3,058	3,048	3,047	3,041	3,039	3,030	3,018	3,011	3,000	2,982	2,975	36,314

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $284,622 and Smith $106,497.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Crist 3.5% annually; Smith 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	
3	Less: Accumulated Depreciation (C)	(1,488,100)	(1,495,752)	(1,503,404)	(1,511,056)	(1,518,708)	(1,526,360)	(1,534,012)	(1,541,664)	(1,549,316)	(1,556,968)	(1,564,620)	(1,572,272)	(1,579,924)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,294,500	1,286,848	1,279,196	1,271,544	1,263,892	1,256,240	1,248,588	1,240,936	1,233,284	1,225,632	1,217,980	1,210,328	1,202,676	
6	Average Net Investment		1,290,674	1,283,022	1,275,370	1,267,718	1,260,066	1,252,414	1,244,762	1,237,110	1,229,458	1,221,806	1,214,154	1,206,502	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		7,170	7,127	7,085	7,042	7,000	6,957	6,915	6,872	6,830	6,787	6,745	6,702	83,232
	b Debt Component (Line 6 x Debt Component x 1/12)		2,309	2,295	2,282	2,268	2,254	2,241	2,227	2,213	2,200	2,186	2,172	2,158	26,805
8	Investment Expenses														
	a Depreciation (E)		7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	91,824
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		17,131	17,074	17,019	16,962	16,906	16,850	16,794	16,737	16,682	16,625	16,569	16,512	201,861
	a Recoverable Costs Allocated to Energy		1,318	1,313	1,309	1,305	1,300	1,296	1,292	1,287	1,283	1,279	1,275	1,270	15,527
	b Recoverable Costs Allocated to Demand		15,813	15,761	15,710	15,657	15,606	15,554	15,502	15,450	15,399	15,346	15,294	15,242	186,334
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		1,276	1,271	1,266	1,265	1,261	1,260	1,255	1,249	1,246	1,240	1,232	1,228	15,049
13	Retail Demand-Related Recoverable Costs (I)		15,271	15,221	15,172	15,121	15,071	15,021	14,971	14,921	14,871	14,820	14,770	14,720	179,950
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		16,547	16,492	16,438	16,386	16,332	16,281	16,226	16,170	16,117	16,060	16,002	15,948	194,999

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E.s 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	77,814	77,322	76,830	76,338	75,846	75,354	74,862	74,370	73,878	73,386	72,894	72,402	71,910	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	256,776	256,284	255,792	255,300	254,808	254,316	253,824	253,332	252,840	252,348	251,856	251,364	250,872	
6	Average Net Investment		256,530	256,038	255,546	255,054	254,562	254,070	253,578	253,086	252,594	252,102	251,610	251,118	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,425	1,422	1,420	1,417	1,414	1,411	1,409	1,406	1,403	1,400	1,398	1,395	16,920
	b Debt Component (Line 6 x Debt Component x 1/12)		459	458	457	456	455	455	454	453	452	451	450	449	5,449
8	Investment Expenses														
	a Depreciation (E)		492	492	492	492	492	492	492	492	492	492	492	492	5,904
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,376	2,372	2,369	2,365	2,361	2,358	2,355	2,351	2,347	2,343	2,340	2,336	28,273
	a Recoverable Costs Allocated to Energy		183	182	182	182	182	181	181	181	181	180	180	180	2,175
	b Recoverable Costs Allocated to Demand		2,193	2,190	2,187	2,183	2,179	2,177	2,174	2,170	2,166	2,163	2,160	2,156	26,098
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		177	176	176	176	177	176	176	176	176	175	174	174	2,109
13	Retail Demand-Related Recoverable Costs (I)		2,118	2,115	2,112	2,108	2,104	2,102	2,100	2,096	2,092	2,089	2,086	2,082	25,204
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,295	2,291	2,288	2,284	2,281	2,278	2,276	2,272	2,268	2,264	2,260	2,256	27,313

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E.s 1501, 1535, 1555, & 1819
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	
3	Less: Accumulated Depreciation (C)	(5,695,307)	(5,730,186)	(5,765,065)	(5,799,944)	(5,834,823)	(5,869,702)	(5,904,581)	(5,939,460)	(5,974,339)	(6,009,218)	(6,044,097)	(6,078,976)	(6,113,855)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	9,254,817	9,219,938	9,185,059	9,150,180	9,115,301	9,080,422	9,045,543	9,010,664	8,975,785	8,940,906	8,906,027	8,871,148	8,836,269	
6	Average Net Investment		9,237,378	9,202,499	9,167,620	9,132,741	9,097,862	9,062,983	9,028,104	8,993,225	8,958,346	8,923,467	8,888,588	8,853,709	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		51,314	51,120	50,926	50,732	50,539	50,345	50,151	49,957	49,764	49,570	49,376	49,182	602,976
	b Debt Component (Line 6 x Debt Component x 1/12)		16,526	16,463	16,401	16,338	16,276	16,214	16,151	16,089	16,026	15,964	15,902	15,839	194,189
8	Investment Expenses														
	a Depreciation (E)		34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	418,548
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		25,998	25,998	25,998	25,998	25,998	25,998	25,998	25,998	25,998	25,998	25,998	25,998	311,976
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		128,717	128,460	128,204	127,947	127,692	127,436	127,179	126,923	126,667	126,411	126,155	125,898	1,527,689
	a Recoverable Costs Allocated to Energy		9,901	9,882	9,862	9,842	9,822	9,803	9,783	9,763	9,744	9,724	9,704	9,684	117,514
	b Recoverable Costs Allocated to Demand		118,816	118,578	118,342	118,105	117,870	117,633	117,396	117,160	116,923	116,687	116,451	116,214	1,410,175
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		9,582	9,565	9,541	9,542	9,529	9,530	9,506	9,474	9,463	9,431	9,380	9,362	113,905
13	Retail Demand-Related Recoverable Costs (I)		114,745	114,515	114,287	114,058	113,831	113,602	113,373	113,145	112,917	112,689	112,461	112,232	1,361,855
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		124,327	124,080	123,828	123,600	123,360	123,132	122,879	122,619	122,380	122,120	121,841	121,594	1,475,760

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 2.8% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E.s 1601, 1620 & 1638
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	6,900,000	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	
3	Less: Accumulated Depreciation (C)	(35,201)	(35,570)	(35,939)	(36,308)	(36,677)	(37,046)	(37,415)	(37,784)	(38,153)	(38,522)	(38,891)	(39,260)	(39,629)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	6,900,000	6,900,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	98,933	98,564	98,195	97,826	97,457	97,088	96,719	96,350	95,981	95,612	95,243	6,994,874	6,994,505	
6	Average Net Investment		98,749	98,380	98,011	97,642	97,273	96,904	96,535	96,166	95,797	95,428	3,545,059	6,994,690	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		549	547	544	542	540	538	536	534	532	530	19,693	38,856	63,941
	b Debt Component (Line 6 x Debt Component x 1/12)		177	176	175	175	174	173	173	172	171	171	6,342	12,514	20,593
8	Investment Expenses														
	a Depreciation (E)		369	369	369	369	369	369	369	369	369	369	369	369	4,428
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,095	1,092	1,088	1,086	1,083	1,080	1,078	1,075	1,072	1,070	26,404	51,739	88,962
	a Recoverable Costs Allocated to Energy		84	84	84	84	83	83	83	83	82	82	2,031	3,980	6,843
	b Recoverable Costs Allocated to Demand		1,011	1,008	1,004	1,002	1,000	997	995	992	990	988	24,373	47,759	82,119
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		81	81	81	81	81	81	81	81	80	80	1,963	3,848	6,619
13	Retail Demand-Related Recoverable Costs (I)		976	973	970	968	966	963	961	958	956	954	23,538	46,123	79,306
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,057	1,054	1,051	1,049	1,047	1,044	1,042	1,039	1,036	1,034	25,501	49,971	85,925

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 4397 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E.s 1031, 1158, 1167, 1199, 1250, 1287
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	123,281,904	
3	Less: Accumulated Depreciation (C)	(22,645,684)	(23,007,199)	(23,368,714)	(23,730,229)	(24,091,744)	(24,453,259)	(24,814,774)	(25,176,289)	(25,537,804)	(25,899,319)	(26,260,834)	(26,622,349)	(26,983,864)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	100,636,220	100,274,705	99,913,190	99,551,675	99,190,160	98,828,645	98,467,130	98,105,615	97,744,100	97,382,585	97,021,070	96,659,555	96,298,040	
6	Average Net Investment		100,455,463	100,093,948	99,732,433	99,370,918	99,009,403	98,647,888	98,286,373	97,924,858	97,563,343	97,201,828	96,840,313	96,478,798	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		558,030	556,022	554,014	552,005	549,997	547,989	545,981	543,973	541,964	539,956	537,948	535,940	6,563,819
	b Debt Component (Line 6 x Debt Component x 1/12)		179,715	179,068	178,421	177,775	177,128	176,481	175,834	175,188	174,541	173,894	173,247	172,601	2,113,893
8	Investment Expenses														
	a Depreciation (E)		358,996	358,996	358,996	358,996	358,996	358,996	358,996	358,996	358,996	358,996	358,996	358,996	4,307,952
	b Amortization (F)		2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	2,519	30,228
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,099,260	1,096,605	1,093,950	1,091,295	1,088,640	1,085,985	1,083,330	1,080,676	1,078,020	1,075,365	1,072,710	1,070,056	13,015,892
	a Recoverable Costs Allocated to Energy		1,099,260	1,096,605	1,093,950	1,091,295	1,088,640	1,085,985	1,083,330	1,080,676	1,078,020	1,075,365	1,072,710	1,070,056	13,015,892
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		1,063,823	1,061,446	1,058,326	1,058,082	1,056,206	1,055,735	1,052,661	1,048,665	1,046,893	1,042,941	1,036,873	1,034,476	12,616,127
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,063,823	1,061,446	1,058,326	1,058,082	1,056,206	1,055,735	1,052,661	1,048,665	1,046,893	1,042,941	1,036,873	1,034,476	12,616,127

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5 % annually; Part of PE 1158 and 1287 depreciable at 3.5% annually.
(F) Portions of PE 1158 and 1287 have a 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, & 1628
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	936,679	936,679	936,679	936,679	936,679	936,679	936,679	936,679	936,679	936,679	936,679	936,679	936,679	
3	Less: Accumulated Depreciation (C)	(187,218)	(189,947)	(192,676)	(195,405)	(198,134)	(200,863)	(203,592)	(206,321)	(209,050)	(211,779)	(214,508)	(217,237)	(219,966)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	749,461	746,732	744,003	741,274	738,545	735,816	733,087	730,358	727,629	724,900	722,171	719,442	716,713	
6	Average Net Investment		748,097	745,368	742,639	739,910	737,181	734,452	731,723	728,994	726,265	723,536	720,807	718,078	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,156	4,141	4,125	4,110	4,095	4,080	4,065	4,050	4,034	4,019	4,004	3,989	48,868
	b Debt Component (Line 6 x Debt Component x 1/12)		1,338	1,333	1,329	1,324	1,319	1,314	1,309	1,304	1,299	1,294	1,290	1,285	15,738
8	Investment Expenses														
	a Depreciation (E)		2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	32,748
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,223	8,203	8,183	8,163	8,143	8,123	8,103	8,083	8,062	8,042	8,023	8,003	97,354
	a Recoverable Costs Allocated to Energy		633	631	629	628	626	625	623	622	620	619	617	616	7,489
	b Recoverable Costs Allocated to Demand		7,590	7,572	7,554	7,535	7,517	7,498	7,480	7,461	7,442	7,423	7,406	7,387	89,865
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		613	611	609	609	607	608	605	604	602	600	596	596	7,260
13	Retail Demand-Related Recoverable Costs (I)		7,330	7,313	7,295	7,277	7,259	7,241	7,224	7,205	7,187	7,169	7,152	7,134	86,786
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,943	7,924	7,904	7,886	7,866	7,849	7,829	7,809	7,789	7,769	7,748	7,730	94,046

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist, $919,836; Smith $16,843.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Crist 3.5%; Smith 3.3% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(18,517)	(18,700)	(18,883)	(19,066)	(19,249)	(19,432)	(19,615)	(19,798)	(19,981)	(20,164)	(20,347)	(20,530)	(20,713)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	44,353	44,170	43,987	43,804	43,621	43,438	43,255	43,072	42,889	42,706	42,523	42,340	42,157	
6	Average Net Investment		44,262	44,079	43,896	43,713	43,530	43,347	43,164	42,981	42,798	42,615	42,432	42,249	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		246	245	244	243	242	241	240	239	238	237	236	235	2,886
	b Debt Component (Line 6 x Debt Component x 1/12)		79	79	79	78	78	78	77	77	77	76	76	76	930
8	Investment Expenses														
	a Depreciation (E)		183	183	183	183	183	183	183	183	183	183	183	183	2,196
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		508	507	506	504	503	502	500	499	498	496	495	494	6,012
	a Recoverable Costs Allocated to Energy		508	507	506	504	503	502	500	499	498	496	495	494	6,012
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		492	491	490	489	488	488	486	484	484	481	478	478	5,829
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		492	491	490	489	488	488	486	484	484	481	478	478	5,829

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330, 1461, 1462
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	
3	Less: Accumulated Depreciation (C)	(5,334,741)	(5,419,222)	(5,503,703)	(5,588,184)	(5,672,665)	(5,757,146)	(5,841,627)	(5,926,108)	(6,010,589)	(6,095,070)	(6,179,551)	(6,264,032)	(6,348,513)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	24,504,937	24,420,456	24,335,975	24,251,494	24,167,013	24,082,532	23,998,051	23,913,570	23,829,089	23,744,608	23,660,127	23,575,646	23,491,165	
6	Average Net Investment		24,462,697	24,378,216	24,293,735	24,209,254	24,124,773	24,040,292	23,955,811	23,871,330	23,786,849	23,702,368	23,617,887	23,533,406	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		135,890	135,421	134,952	134,482	134,013	133,544	133,075	132,605	132,136	131,667	131,197	130,728	1,599,710
	b Debt Component (Line 6 x Debt Component x 1/12)		43,764	43,613	43,461	43,310	43,159	43,008	42,857	42,706	42,555	42,404	42,252	42,101	515,190
8	Investment Expenses														
	a Depreciation (E)		84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	1,013,772
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		264,135	263,515	262,894	262,273	261,653	261,033	260,413	259,792	259,172	258,552	257,930	257,310	3,128,672
	a Recoverable Costs Allocated to Energy		264,135	263,515	262,894	262,273	261,653	261,033	260,413	259,792	259,172	258,552	257,930	257,310	3,128,672
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		255,620	255,066	254,333	254,291	253,858	253,762	253,041	252,097	251,689	250,756	249,313	248,754	3,032,580
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		255,620	255,066	254,333	254,291	253,858	253,762	253,041	252,097	251,689	250,756	249,313	248,754	3,032,580

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances and Ending Balances: Crist $13,997,696; Smith $15,715,201; Scholz $126,781.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Crist 3.5%; Smith 3.3%; Scholz 4.1% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E.s 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.s 1178, 1227 & 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	20,049,424	
3	Less: Accumulated Depreciation (C)	(1,890,300)	(1,948,784)	(2,007,268)	(2,065,752)	(2,124,236)	(2,182,720)	(2,241,204)	(2,299,688)	(2,358,172)	(2,416,656)	(2,475,140)	(2,533,624)	(2,592,108)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	18,159,124	18,100,640	18,042,156	17,983,672	17,925,188	17,866,704	17,808,220	17,749,736	17,691,252	17,632,768	17,574,284	17,515,800	17,457,316	
6	Average Net Investment		18,129,882	18,071,398	18,012,914	17,954,430	17,895,946	17,837,462	17,778,978	17,720,494	17,662,010	17,603,526	17,545,042	17,486,558	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		100,711	100,387	100,062	99,737	99,412	99,087	98,762	98,437	98,112	97,788	97,463	97,138	1,187,096
	b Debt Component (Line 6 x Debt Component x 1/12)		32,434	32,330	32,225	32,120	32,016	31,911	31,807	31,702	31,597	31,493	31,388	31,283	382,306
8	Investment Expenses														
	a Depreciation (E)		58,484	58,484	58,484	58,484	58,484	58,484	58,484	58,484	58,484	58,484	58,484	58,484	701,808
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		191,629	191,201	190,771	190,341	189,912	189,482	189,053	188,623	188,193	187,765	187,335	186,905	2,271,210
	a Recoverable Costs Allocated to Energy		14,741	14,708	14,675	14,642	14,609	14,576	14,543	14,509	14,476	14,443	14,410	14,377	174,709
	b Recoverable Costs Allocated to Demand		176,888	176,493	176,096	175,699	175,303	174,906	174,510	174,114	173,717	173,322	172,925	172,528	2,096,501
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		14,266	14,236	14,197	14,196	14,174	14,170	14,131	14,079	14,058	14,008	13,929	13,899	169,343
13	Retail Demand-Related Recoverable Costs (I)		170,827	170,445	170,062	169,679	169,296	168,913	168,530	168,148	167,765	167,383	167,000	166,616	2,024,664
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		185,093	184,681	184,259	183,875	183,470	183,083	182,661	182,227	181,823	181,391	180,929	180,515	2,194,007

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E.s 1204 & 1299
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	6,154,686	
3	Less: Accumulated Depreciation (C)	(1,322,454)	(1,340,407)	(1,358,360)	(1,376,313)	(1,394,266)	(1,412,219)	(1,430,172)	(1,448,125)	(1,466,078)	(1,484,031)	(1,501,984)	(1,519,937)	(1,537,890)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	4,832,232	4,814,279	4,796,326	4,778,373	4,760,420	4,742,467	4,724,514	4,706,561	4,688,608	4,670,655	4,652,702	4,634,749	4,616,796	
6	Average Net Investment		4,823,256	4,805,303	4,787,350	4,769,397	4,751,444	4,733,491	4,715,538	4,697,585	4,679,632	4,661,679	4,643,726	4,625,773	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		26,793	26,693	26,594	26,494	26,394	26,295	26,195	26,095	25,995	25,896	25,796	25,696	314,936
	b Debt Component (Line 6 x Debt Component x 1/12)		8,629	8,597	8,565	8,532	8,500	8,468	8,436	8,404	8,372	8,340	8,308	8,276	101,427
8	Investment Expenses														
	a Depreciation (E)		17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	215,436
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		53,375	53,243	53,112	52,979	52,847	52,716	52,584	52,452	52,320	52,189	52,057	51,925	631,799
	a Recoverable Costs Allocated to Energy		4,106	4,096	4,086	4,075	4,065	4,055	4,045	4,035	4,025	4,015	4,004	3,994	48,601
	b Recoverable Costs Allocated to Demand		49,269	49,147	49,026	48,904	48,782	48,661	48,539	48,417	48,295	48,174	48,053	47,931	583,198
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		3,974	3,965	3,953	3,951	3,944	3,942	3,930	3,915	3,909	3,894	3,870	3,861	47,108
13	Retail Demand-Related Recoverable Costs (I)		47,581	47,463	47,346	47,228	47,110	46,994	46,876	46,758	46,640	46,523	46,406	46,289	563,214
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		51,555	51,428	51,299	51,179	51,054	50,936	50,806	50,673	50,549	50,417	50,276	50,150	610,322

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) 3.5% annually.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1067, 1095, 1222, 1233, 1279, 1362, 1468, 1469, 1512, 1513, 1517, 1551, 1552, 1646, 1647, 1684, 1810, 1824, & 1826
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions	-	0	0	0	0	0	0	0	0	0	0	166,666	166,666	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	798,624,487	
3	Less: Accumulated Depreciation (C)	(83,153,235)	(85,482,364)	(87,811,493)	(90,140,622)	(92,469,751)	(94,798,880)	(97,128,009)	(99,457,138)	(101,786,267)	(104,115,396)	(106,444,525)	(108,773,654)	(111,102,783)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	166,666	333,332	
5	Net Investment (Lines 2 + 3 + 4) (A)	715,471,252	713,142,123	710,812,994	708,483,865	706,154,736	703,825,607	701,496,478	699,167,349	696,838,220	694,509,091	692,179,962	690,017,499	687,855,036	
6	Average Net Investment		714,306,688	711,977,559	709,648,430	707,319,301	704,990,172	702,661,043	700,331,914	698,002,785	695,673,656	693,344,527	691,098,731	688,936,268	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,967,974	3,955,035	3,942,097	3,929,159	3,916,220	3,903,282	3,890,344	3,877,405	3,864,467	3,851,529	3,839,053	3,827,041	46,763,606
	b Debt Component (Line 6 x Debt Component x 1/12)		1,277,895	1,273,728	1,269,561	1,265,394	1,261,227	1,257,061	1,252,894	1,248,727	1,244,560	1,240,393	1,236,376	1,232,507	15,060,323
8	Investment Expenses														
	a Depreciation (E)		2,316,362	2,316,362	2,316,362	2,316,362	2,316,362	2,316,362	2,316,362	2,316,362	2,316,362	2,316,362	2,316,362	2,316,362	27,796,344
	b Amortization (F)		12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	12,767	153,204
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		103,899	103,899	103,899	103,899	103,899	103,899	103,899	103,899	103,899	103,899	103,899	103,899	1,246,788
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,678,897	7,661,791	7,644,686	7,627,581	7,610,475	7,593,371	7,576,266	7,559,160	7,542,055	7,524,950	7,508,457	7,492,576	91,020,265
	a Recoverable Costs Allocated to Energy		7,678,897	7,661,791	7,644,686	7,627,581	7,610,475	7,593,371	7,576,266	7,559,160	7,542,055	7,524,950	7,508,457	7,492,576	91,020,265
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		7,431,351	7,416,144	7,395,740	7,395,440	7,383,737	7,381,861	7,361,779	7,335,245	7,324,283	7,298,059	7,257,615	7,243,444	88,224,698
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,431,351	7,416,144	7,395,740	7,395,440	7,383,737	7,381,861	7,361,779	7,335,245	7,324,283	7,298,059	7,257,615	7,243,444	88,224,698

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning and Ending Balances: Crist $778,545,848; Smith $12,931,385; Daniel $6,772,129, Scholz $375,125.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Crist 3.5%; Smith 3.3%; Smith CT 3.6%; Daniel 2.8%; Scholz 4.1%. Portions of PE 1222 are transmission: 2.0%, 2.3%, 3.6%, and 2.5%.
(F) Portions of PE 1222 and 1233 have a 7 year amortization period. PE 1279 amortization begins in 2013.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.1280
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		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	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	
3	Less: Accumulated Depreciation (C)	(28,678)	(29,212)	(29,746)	(30,280)	(30,814)	(31,348)	(31,882)	(32,021)	(32,021)	(32,021)	(32,021)	(32,021)	(32,021)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	3,343	2,809	2,275	1,741	1,207	673	139	0	0	0	0	0	0	
6	Average Net Investment		3,076	2,542	2,008	1,474	940	406	70	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		17	14	11	8	5	2	0	0	0	0	0	0	57
	b Debt Component (Line 6 x Debt Component x 1/12)		6	5	4	3	2	1	0	0	0	0	0	0	21
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		534	534	534	534	534	534	139	0	0	0	0	0	3,343
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		557	553	549	545	541	537	139	0	0	0	0	0	3,421
	a Recoverable Costs Allocated to Energy		43	43	42	42	42	41	11	0	0	0	0	0	264
	b Recoverable Costs Allocated to Demand		514	510	507	503	499	496	128	0	0	0	0	0	3,157
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (H)		42	42	41	41	41	40	11	0	0	0	0	0	258
13	Retail Demand-Related Recoverable Costs (I)		496	493	490	486	482	479	124	0	0	0	0	0	3,050
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		538	535	531	527	523	519	135	0	0	0	0	0	3,308

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) 5 year amortization beginning 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0015 line loss multiplier.
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Mercury Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 line loss multiplier.
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Working Capital, Annual NOx Expenses
For Project: Annual Nox Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	953,131	927,211	900,622	869,702	833,242	801,112	766,148	719,307	670,874	632,376	604,481	576,523	540,827	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	953,131	927,211	900,622	869,702	833,242	801,112	766,148	719,307	670,874	632,376	604,481	576,523	540,827	
4	Average Net Working Capital Balance		940,171	913,917	885,162	851,472	817,177	783,630	742,728	695,091	651,625	618,429	590,502	558,675	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		5,223	5,077	4,917	4,730	4,539	4,353	4,126	3,861	3,620	3,435	3,280	3,103	50,264
	b Debt Component (Line 4 x Debt Component x 1/12)		1,682	1,635	1,584	1,523	1,462	1,402	1,329	1,244	1,166	1,106	1,056	999	16,188
6	Total Return Component (D)		6,905	6,712	6,501	6,253	6,001	5,755	5,455	5,105	4,786	4,541	4,336	4,102	66,452
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual Nox Allowance Expense		25,920	26,589	30,920	36,460	32,130	34,964	46,841	48,433	38,498	27,895	27,958	35,696	412,304
8	Net Expenses (E)		25,920	26,589	30,920	36,460	32,130	34,964	46,841	48,433	38,498	27,895	27,958	35,696	412,304
9	Total System Recoverable Expenses (Lines 6 + 8)		32,825	33,301	37,421	42,713	38,131	40,719	52,296	53,538	43,284	32,436	32,294	39,798	478,756
	a Recoverable Costs Allocated to Energy		32,825	33,301	37,421	42,713	38,131	40,719	52,296	53,538	43,284	32,436	32,294	39,798	478,756
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (B)		31,767	32,233	36,202	41,413	36,995	39,585	50,815	51,952	42,034	31,458	31,215	38,475	464,144
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		31,767	32,233	36,202	41,413	36,995	39,585	50,815	51,952	42,034	31,458	31,215	38,475	464,144

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 line loss multiplier.
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal Nox Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	4	4	4	4	4	4	4	4	4	4	4	4	4	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	4	4	4	4	4	4	4	4	4	4	4	4	4	
4	Average Net Working Capital Balance		4	4	4	4	4	4	4	4	4	4	4	4	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 line loss multiplier.
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2013 - December 2013
Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	7,841,670	7,788,876	7,736,867	7,667,769	7,589,807	7,528,768	7,456,922	7,358,979	7,255,994	7,183,198	7,125,568	7,070,521	6,994,439	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(533,973)	(513,611)	(493,249)	(472,887)	(452,525)	(432,163)	(411,801)	(391,439)	(371,077)	(350,715)	(330,353)	(309,991)	(289,629)	
3	Total Working Capital Balance	7,307,697	7,275,265	7,243,618	7,194,882	7,137,282	7,096,605	7,045,121	6,967,540	6,884,917	6,832,483	6,795,215	6,760,530	6,704,810	
4	Average Net Working Capital Balance		7,291,481	7,259,442	7,219,250	7,166,082	7,116,944	7,070,863	7,006,331	6,926,229	6,858,700	6,813,849	6,777,873	6,732,670	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		40,504	40,326	40,103	39,808	39,535	39,279	38,920	38,475	38,100	37,851	37,651	37,400	467,952
	b Debt Component (Line 4 x Debt Component x 1/12)		13,044	12,987	12,915	12,820	12,732	12,650	12,534	12,391	12,270	12,190	12,126	12,045	150,704
6	Total Return Component (D)		53,548	53,313	53,018	52,628	52,267	51,929	51,454	50,866	50,370	50,041	49,777	49,445	618,656
7	Expenses														
	a Gains		(20,362)	(20,362)	(20,362)	(20,362)	(20,362)	(20,362)	(20,362)	(20,362)	(20,362)	(20,362)	(20,362)	(20,362)	(244,344)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		52,794	52,009	69,098	77,962	61,039	71,846	97,943	102,985	72,796	57,630	55,047	76,082	847,231
8	Net Expenses (E)		32,432	31,647	48,736	57,600	40,677	51,484	77,581	82,623	52,434	37,268	34,685	55,720	602,887
9	Total System Recoverable Expenses (Lines 6 + 8)		85,980	84,960	101,754	110,228	92,944	103,413	129,035	133,489	102,804	87,309	84,462	105,165	1,221,543
	a Recoverable Costs Allocated to Energy		85,980	84,960	101,754	110,228	92,944	103,413	129,035	133,489	102,804	87,309	84,462	105,165	1,221,543
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9663133	0.9664890	0.9659864	0.9681134	0.9687540	0.9706894	0.9702343	0.9689250	0.9696711	0.9683956	0.9651443	0.9653016	
11	Demand Jurisdictional Factor		0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
12	Retail Energy-Related Recoverable Costs (B)		83,208	82,236	98,440	106,873	90,175	100,532	125,382	129,535	99,836	84,676	81,640	101,668	1,184,201
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		83,208	82,236	98,440	106,873	90,175	100,532	125,382	129,535	99,836	84,676	81,640	101,668	1,184,201

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x 1.0015 line loss multiplier.
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Air Quality Assurance Testing
PEs 1006 and 1244

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This line item includes the audit test trailer and associated support equipment used to conduct Relative Accuracy Test Audits (RATAs) on the Continuous Emission Monitoring Systems (CEMS) as required by the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The RATA test trailer CEM system was replaced during the 2002-2003 recovery period. The CEMS trailer was also replaced in 2010. These replacements provide Gulf with the accuracy and reliability needed to accurately measure SO_2, NOx, and CO_2 and to further maintain compliance with CAAA requirements.

Project-to-Date: Plant-in-service of $350,812 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 5, 6 & 7 Precipitator Projects
PEs 1038, 1119, 1216, 1243, and 1249

FPSC Approval: Order No. PSC-94-0044-FOF-EI
Order No. PSC-09-0759-FOF-EI

Description:
The Crist precipitator projects are necessary to improve particulate removal capabilities as a result of burning low sulfur coal. The larger more efficient precipitators with increased collection areas improve particulate collection efficiency.

Accomplishments:
The precipitators have successfully reduced particulate emissions while burning low sulfur coal. The upgraded Crist Unit 7 precipitator was placed in service during 2004 as part of the FDEP agreement.

Project-to-Date: Plant-in-service of $35,301,539 projected at December 2013.

Progress Summary: The Plant Crist Unit 6 precipitator upgrade was placed in service in April 2012. Prudently incurred costs associated with the Crist Unit 6 precipitator project were approved for inclusion in the ECRC in Order No. PSC-09-0759-FOF-EI.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 7 Flue Gas Conditioning
PE 1228

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This project included the injection of sulfur trioxide into the flue gas to enhance particulate removal and improve the collection characteristics of fly ash. Retirement of the Plant Crist Unit 7 flue gas conditioning system was completed during July 2005.

Accomplishments:
The system enhanced particulate removal in the precipitator.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Low NO_x Burners, Crist 6 & 7
PEs 1234, 1236, 1242, and 1284

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Low NO_x burners are unique burners installed to decrease the NO_x emissions that are formed during the combustion process. This equipment was installed to meet the requirements of the 1990 Clean Air Act Amendments.

Accomplishments:
The Low NO_x burner systems have proven effective in reducing NO_x emissions. The low NO_x burners on Crist Unit 7 were replaced during the 2003-2004 time frame and the Crist Unit 6 burners were replaced during December 2005.

Project-to-Date: Plant-in-service of $9,097,924 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CEMs – Plant Crist, Scholz, Smith, and Daniel
PEs 1001, 1060, 1154, 1164, 1188, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1358, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 1592, 1658, 1829, and 1830

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Continuous Emission Monitoring (CEM) line item includes dilution extraction emission monitors that measure the concentrations of sulfur dioxide (SO_2), carbon dioxide (CO_2) and nitrogen oxides (NO_x) in the flue gas. Opacity and flow monitors were also installed under this line item. All CEMs monitors were installed pursuant to the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The systems at both Gulf and Mississippi Power continue to successfully exceed routine quality assurance/quality control (QA/QC) audits as required by the 1990 CAAA.

Project-to-Date: Plant-in-service of $7,411,265 projected at December 2013.

Progress Summary:
The Plant Scholz Units 1 & 2 CEMS analyzer replacements and the Smith Unit 1 gas analyzers and opacity monitor replacements were completed in 2001 and 2002. The Plant Crist Unit 6 & 7 and the Plant Scholz Units 1&2 flow monitors were replaced during 2005. The Plant Daniel Units 1&2 gas analyzers were also replaced during 2005 and the flow monitors were replaced during 2007. During 2008, the opacity, flow, and gas monitors at Plant Smith and opacity and gas monitors at Plant Scholz were replaced. During the 2009 recovery period, the CEMS project included replacement of opacity monitors at Plant Crist on Units 4 through 7 and the installation of CEMs equipment for the new Plant Crist scrubber stack to monitor SO_2, NOx, CO_2 and flow. Plant Crist completed the installation of two CEMS bypass monitoring systems for Units 4 through 7 in 2011.

Projections: In-Service

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Substation Contamination Remediation
PEs 1007, 2859, 3400, 3412, and 3477

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
Three groundwater treatment systems were purchased for the treatment of contaminated groundwater at substation sites.

Accomplishments:
Systems have proven effective in groundwater remediation.

Project-to-Date: Plant-in-service of $1,951,024 projected at December 2013.

Progress Summary: In-Service

Projections: Projected 2013 expenditures total $704,000 for the Highland City substation remediation project.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Raw Water Flow Meters; Crist and Smith
PEs 1155 and 1606

FPSC Approval: Order No. PSC-96-1171-FOF-EI

Description:
The Raw Water Flow Meters capital project was necessary for Gulf to comply with the Plant Crist and Plant Smith Consumptive Use and Individual Water Use permits issued by the Northwest Florida Water Management District (NWFWMD). These permits require the installation and monitoring of in-line totaling water flow meters on all existing and future water supply wells. Gulf incurred costs related to the installation and operation of new in-line totaling water flow meters at Plant Crist and Plant Smith for implementation of this new activity.

Accomplishments:
The raw water flow meters have been installed at Plant Crist and Plant Smith.

Project-to-Date: Plant-in-service of $242,973 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Cooling Tower Cell
PE 1232

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Crist Cooling Tower cell is a pollution control device which allows condenser cooling water to be continually reinjected into the condenser. The cooling tower reduces water discharge temperatures to meet the National Pollution Discharge Elimination System (NPDES) industrial wastewater requirements.

Accomplishments:
Plant Crist has maintained compliance with the temperature discharge limits as required by the facility's NPDES Permit. The original cooling tower cell was retired during July 2007 when the new Crist Unit 7 cooling tower was placed-in-service.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Dechlorination System
PE 1248 and PE 1180

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
State and Federal Pollution Discharge Elimination System permits require significant reductions in chlorine concentrations prior to discharge from the plant. The Crist dechlorination system uses sodium bisulfite to chemically eliminate the residual chlorine present in the plant industrial wastewater prior to discharge.

Accomplishments:
The system has been effective in maintaining chlorine discharge limits.

Project-to-Date: Plant-in-service of $382,060 projected at December 2013.

Progress Summary: During 2011 Plant Crist replaced the existing sodium bisulfate storage tank and installed a new dechlorination system for the Unit 6 and Unit 7 cooling tower blowdowns and the ECUA return water pit. These systems are necessary in order to dechlorinate the industrial wastewater prior to discharge.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Diesel Fuel Oil Remediation
PE 1270

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The Crist diesel fuel oil remediation project included installing monitoring wells in the vicinity of the Crist diesel tank systems to determine if groundwater contamination was present. The project also included the installation of an impervious cap to reduce migration of contaminants to groundwater.

Accomplishments: Monitoring wells and an impervious cap were installed.

Project-to-Date: Plant-in-service of $68,923 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Bulk Tanker Unloading Secondary Containment
PE 1271

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The Crist Bulk Tanker Unloading Secondary Containment project was necessary to minimize the potential risk of an uncontrolled discharge of pollutants into the waters of the United States. Secondary containment must be installed for tank unloading racks pursuant to the Federal Spill Prevention Control and Countermeasures (SPCC) regulation (40 CFR Part 112).

Accomplishments:
The Plant Crist unloading area secondary containment complies with current SPCC regulatory requirements.

Project-to-Date: Plant-in-service of $101,495 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist IWW Sampling System
PE 1275

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The 1993 revision to Plant Crist's National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit moved the compliance point from the end of the discharge canal to a point upstream of Thompson's Bayou. To allow for this sample point modification, an access dock was constructed in the discharge canal. The Crist Industrial Wastewater (IWW) project also included a small building for monitoring and sampling equipment.

Accomplishments:
The dock is complete and samples are being collected at the required compliance point.

Project-to-Date: Plant-in-service of $59,543 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Sodium Injection System
PEs 1214 and 1413

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
The Sodium Injection System line item includes silo storage systems and associated components that inject sodium carbonate directly onto the coal feeder belt to enhance precipitator performance when burning low sulfur coal. Sodium injection is used at Plant Smith on Units 1 and 2 and at Plant Crist on Units 4 and 5. The injection of sodium carbonate as an additive to low sulfur coal reduces opacity levels to maintain compliance with the Clean Air Act provisions.

Accomplishments:
The silo storage and injection system components at Plants Smith and Crist have been installed. These systems are fully operational.

Project-to-Date: Plant-in-service of $391,119 projected at December 2013.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Stormwater Collection System
PE 1446

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The National Pollutant Discharge Elimination System (NPDES) stormwater program requires industrial facilities to install stormwater management systems in order to prevent the unpermitted discharge of contaminated stormwater to the surface waters of the United States.

Accomplishments:
No unpermitted discharges have occurred since system installation.

Project-to-Date: Plant-in-service of $2,782,600 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Waste Water Treatment Facility
PEs 1466 and 1643

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
During the 1990's a wastewater treatment facility was installed at Plant Smith to replace the septic tank system that was installed in the early 1960's. In April 2004 a new waste-water treatment facility with additional capacity was installed to replace the facility installed in the 1990's. The new treatment plant includes aeration and chlorination of the wastewater prior to discharge in the Plant Smith ash pond.

Accomplishments: Plant Smith has maintained compliance with the NPDES industrial wastewater permit.

Project-to-Date: Plant-in-service of $178,962 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Daniel Ash Management Project
PEs 1501, 1535, 1555, and 1819

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The original Daniel Ash Management project included the installation of a dry ash transport system, lining the bottom of the ash pond, closure and capping of the existing fly ash pond, and the expansion of the landfill area. During 2006 Plant Daniel completed construction of a new on-site ash storage facility in preparation for the completion and closure of the existing landfill area.

Accomplishments: Construction of the new on-site ash storage facility was completed in 2006. Portions of the original Daniel ash storage facility were closed in place during 2010.

Project-to-Date: Plant-in-service of $14,950,124 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Water Conservation
PEs 1601, 1620, & 1638

FPSC Approval: **Order No. PSC-01-1788-FOF-EI and**
Order No. PSC-09-0759-FOF-EI

Description:
Specific Condition nine of Plant Smith's consumptive use permit, issued by the Northwest Florida Water Management District (NWFWMD), requires the plant to implement measures to increase water conservation and efficiency at the facility. Phase I of the Smith Water Conservation project consisted of adding pumps, piping, valves, and controls to reclaim water from the ash pond. Phase II, the Smith Closed Loop Cooling System for the laboratory sampling system, was installed during 2005 to further reduce groundwater usage. Phase III includes investigating the feasibility of utilizing reclaimed water at Plant Smith.

Gulf must determine a suitable method to dispose of beneficially used reclaimed water prior to agreeing to accept reclaimed water from suppliers in the Bay County area. Gulf is determining whether the existing Plant Smith site properties make it feasible for injection of used reclaimed water. Both the test injection well and monitoring well required by the Florida Department of Environmental Protection (FDEP) have been installed. Gulf is currently in the testing phase of the project. Since the testing and evaluation process is not complete and a final agreement has not been reached with the applicable suppliers of reclaimed water, the decision to move forward with the project has not yet been made. During 2013, Gulf anticipates designing a pump system and conducting longer term testing of the well system. Based on the testing results, Gulf will make a final determination on whether to move forward with the Plant Smith Reclaimed Water project. If it is determined that the project should be pursued, additional activities such as installation of additional injection well(s), a pumping system, monitoring well(s) and permitting the wells as a class I injection system would take place. ,

Accomplishments: Plant Smith estimated that the closed loop cooling project reduced water consumption by approximately 125,000 gallons per day.

Project-to-Date: Plant-in-service of $134,134 projected at December 2013.

Progress Summary: See Accomplishments

Projections: The 2013 projection for this line item totals $6.9 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Underground Fuel Tank Replacement
PE 4397

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Underground Fuel Tank Replacement Program provided for the replacement of Gulf's underground storage tanks with new above ground tanks (ASTs). The installation of ASTs significantly reduced the risk of potential petroleum product discharges, groundwater contamination, and subsequent remediation activities.

Accomplishments:
All underground storage tanks have been replaced with above ground tank systems.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist FDEP Agreement for Ozone Attainment
PEs 1031, 1158, 1167, 1199, 1250, and 1287

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description:
The Florida Department of Environmental Protection (FDEP) and Gulf Power entered into an agreement on August 28, 2002 to support Escambia/Santa Rosa County area's effort to maintain compliance with the 8-hour ozone ambient air quality standards. This agreement included a requirement for Gulf to install Selective Catalytic Reduction (SCR) controls on Crist Unit 7, relocate the Crist Unit 7 precipitator, and install a NO_x reduction technology on Plant Crist Unit 6, and Units 4 and 5 if necessary, to meet the NO_x standard specified in the Agreement.

Accomplishments: The new Crist Unit 7 precipitator and SCR were placed in service during 2004 and 2005, respectively. The Crist Unit 6 Selective Non-Catalytic Reduction (SNCR)/low NOx burners with Over-Fired Air (OFA) technologies were then placed in service during November 2005. The Crist Unit 4 and Unit 5 SNCRs were subsequently placed in service during April 2006. The Crist Unit 6 SNCR wasretired during the Spring of 2012 when the Crist Unit 6 SCR was placed in-service.

Project-to-Date: Plant-in-service of $123,281,904 projected at December 2013.

Progress Summary: In-Service. Gulf plans to replace one layer of the Plant Crist Unit 7 SCR catalyst during 2012.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SPCC Compliance
PEs 1272, 1404, and 1628

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The SPCC Compliance projects were required as the result of a more stringent July 2002 revision to Title 40 Code of Federal Regulation Part 112, which is commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The 2002 regulatory revision specifically included oil-containing electrical equipment within the scope of the regulation. Therefore, oil-filled electrical equipment that has the potential to discharge to navigable waters must be provided with appropriate containment and/or diversionary structures to prevent such a discharge. The 2002 revisions also resulted in oil storage containers having a capacity greater than or equal to 55 gallons being classified as bulk storage containers that are subject to the secondary containment requirements in 40 CFR Part 112.8(c).

Accomplishments: The 2006 SPCC project at Plant Crist routed stormwater from the switchyard drains to the new oil skimming sump where any potential spill could be captured, preventing the oil from reaching surface water. During 2009, Plant Smith installed secondary containment for a padmount transformer located along the ash pond discharge canal.

Project-to-Date: Plant-in-service of $936,679 projected at December 2013.

Progress Summary: In-service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Common FTIR Monitor
PE 1297

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The purchase of a Fourier Transform Infrared (FTIR) spectrometer, a device used to measure and analyze various low concentration stack gas emissions, was required at Plant Crist under Title V regulations.

Accomplishments: Purchasing the FTIR instrument has enabled Gulf Power to measure ammonia slip emissions as required by the Plant Crist air permit.

Project-to-Date: Plant-in-service of $62,870 projected at December 2013

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Precipitator Upgrades for Compliance Assurance Monitoring Compliance PEs 1175, 1191, 1305, 1330, 1461, and 1462

FPSC Approval: Order No. PSC-04-1187-FOF-EI

Description: Compliance Assurance Monitoring (CAM) Precipitator Upgrades were required to comply with new CAM regulations. CAM requirements are regulated under Title V of the 1990 Clean Air Act Amendments (CAAA) which requires a method of continuously monitoring particulate emissions. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and the results were included as part of the CAM plans in Gulf's Title V Air Permits effective January 2005. Several precipitator upgrades have been necessary to meet the more stringent surrogate opacity standards under CAM.

Accomplishments: The Plant Smith Unit 2 and Unit 1 precipitator upgrades were placed in service during April 2005 and May 2007, respectively. The Plant Scholz Unit 2 precipitator upgrade was completed during December of 2007. The Plant Crist Units 4 and 5 precipitator upgrades were placed in-service during March of 2008.

Project-to-Date: Plant-in-service of $29,839,678 projected at December 2013.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Groundwater Investigation
PEs 1218 and 1361

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The Florida Department of Environmental Protection (FDEP) lowered the arsenic groundwater standard from 0.05 mg/L to 0.01 mg/L effective January 1, 2005. Historical groundwater monitoring data from Plants Crist and Scholz indicated that these facilities may be unable to comply with the lower standard.

Accomplishments: The Plant Crist and Plant Scholz projects have been canceled because Gulf has been released from any remedial actions at these sites.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Water Conservation Project
PEs 1178, 1227 and 1298

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description:
This project is part of the Plant Crist water conservation and consumptive use efficiency program to reduce the demand for groundwater and surface water withdrawals. Specific Condition six of the Northwest Florida Water Management District Individual Water Use Permit Number19850074 issued January 27, 2005 requires Plant Crist to implement measures to increase water conservation and efficiency at the facility. The first Plant Crist Water Conservation project was placed in service during 2006. This project included installing automatic level controls on the fire water tanks to reduce groundwater usage. The second phase of the project involves utilizing reclaimed water from ECUA's proposed wastewater treatment to reduce the demand for groundwater and surface water withdrawals at Plant Crist. The Northwest Florida Water Management District has agreed that this is a valid project to pursue for continued implementation of the water conservation effort.

Accomplishments: Level controls were installed on the fire tank system during 2006. Portions of the plant Crist reclaimed water project were placed in-service in 2009 and 2010. Gulf began receiving reclaimed water from ECUA in November 2010.

Project-to-Date: Plant-in-service of $20,049,424 projected at December 2013.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: NPDES Permit Compliance Projects
PE 1204 and 1299

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The water quality based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code (F.A.C.) were amended in April 2002 with an effective date of May 2002. The more stringent hardness based standard is included by reference in the Plant Crist National Pollution Discharge Elimination System (NPDES) industrial wastewater permit.

Accomplishments: Plant Crist installed stainless steel condenser tubes on Unit 6 during June 2006 in an effort to meet the revised water quality standards during times of lower hardness in the river water. During 2008 Plant Crist completed the second phase of the project which involved installing a chemical treatment system in the ash pond. During 2010, Gulf completed the third phase of the project that included installing an aeration system in the ash pond. During 2011-2013 Plant Crist has completed installation of a new caustic tank and a sulfuric acid tank as part of the ash pond chemical treatment system.

Project-to-Date: Plant-in-service of $6,154,686 projected at December 2013.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CAIR /CAMR/ CAVR Compliance
PEs 1034, 1035, 1036, 1037, 1067, 1095, 1222, 1233, 1279, 1362, 1468, 1469, 1512, 1513, 1551, 1552, 1646, 1647, 1684, 1810, 1824, and 1826

FPSC Approval: Order No. PSC-06-0972-FOF-EI
Description: This line item includes the prudently incurred costs for compliance with Gulf's Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule or its replacement (the Mercury and Air Toxics Standards (MATS) Rule) and the Clean Air Visibility Rule (CAVR).

Accomplishments:
Immediately after passage of EPA's CAIR and CAMR in 2005, Gulf began extensive engineering, design, and other planning activities to determine the most cost effective strategy for compliance with the CAIR, CAMR, and CAVR requirements. On March 29, 2007, Gulf petitioned the Commission for approval of the Company's plan to achieve and maintain compliance with the CAIR, CAMR, and CAVR. On June 22, 2007, the Office of Public Counsel ("OPC"), the Florida Industrial Power Users' Group ("FIPUG") and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's CAIR/CAMR/CAVR Compliance Plan (the "Plan"). That stipulation identified 10 specific components of Gulf's Plan as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the Plan. On August 14, 2007, the Commission voted to approve the stipulation with the provision that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its Plan into which the Company is moving. The approved Plan includes a more detailed discussion of the planning process and evaluation utilized by Gulf to select the most reasonable and prudent strategy for compliance with these regulations on a plant and/or unit specific basis.

Project-to-Date: Plant-in-service of $798,624,487 projected at December 2013.

Progress Summary: The Plant Crist Unit 6 SCR was placed in-service during April 2012.

Projections: Gulf plans to add an additional catalyst layer to the Plant Crist Unit 6 SCR during 2014. A new catalyst layer will be purchased in late 2013 for installation during the spring of 2014 outage. The 2013 projected cost for this line item is $332,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: General Water Quality
PE 1280

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: Gulf Power purchased a boat during 2007 for surface water sampling required by the Plants Crist, Smith and Scholz National Pollutant Discharge Elimination System (NPDES) permits. The permits had new conditions which required Gulf to establish a biological evaluation plan and implementation schedule for each plant.

Accomplishments: The General Water Quality sampling boat was purchased during 2007. It is currently being used to conduct Gulf's surface water sampling for Plants Crist, Smith, and Scholz.

Project-to-Date: Plant-in-service of $32,021 projected at December 2013.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Mercury Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Mercury Allowances were included as part of Gulf's March 2007 CAIR/CAMR/CAVR Compliance Program. The purchase of allowances in conjunction with the retrofit projects comprised the most reasonable, cost-effective means for Gulf to meet the CAIR, CAMR and CAVR requirements. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating EPA's CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. In response to the CAMR vacatur, mercury allowances have been removed from Gulf's Compliance Program.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Annual NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Although the retrofit installations set forth in Gulf's CAIR/CAMR/CAVR Compliance Program significantly reduce emissions, they will not result in Gulf achieving CAIR / CAVR compliance levels without the purchase of some emission allowances. Thus, Gulf's CAIR/CAMR/CAVR Compliance Program calls for the purchase of allowances. The purchase of allowances in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR, or its replacement program, the Cross-State Air Pollution Rule, requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:

Gulf began surrendering annual NOx allowances during 2009.

Projections: Gulf is not projecting the need to purchase additional annual NOx allowances during 2013. The projected 2013 O&M Annual NOx allowance expenses are $412,304.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Seasonal NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Although the retrofit installations set forth in Gulf's CAIR/CAMR/CAVR Compliance Program significantly reduce emissions, they will not result in Gulf achieving CAIR/CAVR compliance levels without the purchase of some emission allowances. Thus, Gulf's CAIR/CAMR/CAVR Compliance Program calls for the purchase of allowances. The purchase of allowances in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR or its replacement program, the Cross-State Air Pollution Rule (CSAPR), requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:

Gulf began surrendering seasonal NOx allowances during 2009.

Projections: Gulf is not currently projecting the need to purchase additional seasonal NOx allowances during 2013.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SO_2 Allowances

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Part of Gulf's strategy to comply with the Acid Rain Program under the Clean Air Act Amendments of 1990 was to bring several of Gulf's Phase II generating units into compliance early and bank the SO_2 allowances associated with those units. SO_2 reductions under the CAIR program utilize this program requiring an increased rate of surrender beginning in 2010. Gulf's bank was slowly been drawn down over the years due to more allowances being consumed than are allocated to Gulf by EPA. Gulf proposed to meet this shortfall by executing forward contracts to secure allowances supplemented with forward contracts, swaps, and spot market purchases of allowances as prices dictate.

Accomplishments: Gulf executed forward contacts to secure allowances during 2006, 2007, and 2009.

Project-to-Date: N/A

Progress Summary: See Accomplishments

Projections: The projected 2013 O&M SO_2 allowance expenses are $602,887.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.1

Title: Sulfur

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Crist Unit 7 sulfur trioxide (SO_3) flue gas system allowed for the injection of SO_3 into the flue gas stream. The addition of sulfur trioxide to the flue gas improved the collection efficiency of the precipitator when burning a low sulfur coal. Sulfur trioxide agglomerated the particles which in turn enhanced the collection efficiency of the precipitator.

Accomplishments:
The flue gas injection system was retired during 2005.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.2

Title: Air Emission Fees

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Air Emission Fees are the annual fees required by the Florida Department of Environmental Protection (FDEP) and Mississippi Department of Environmental Quality (MDEQ) under Title V of the 1990 Clean Air Act Amendments.

Accomplishments:
Fees have been paid by due dates.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $632,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.3

Title: Title V

FPSC Approval: Order No. PSC-95-0384-FOF-EI

Description:
Title V expenses are associated with the preparation of the Clean Air Act Amendments (CAAA) Title V permit applications and the subsequent implementation of Title V permits. Renewal of the Title V permits is on a five year cycle (i.e. 2005, 2010, etc). Title V permits are periodically revised between renewals to incorporate major changes or modifications of a source.

Accomplishments:
During 2009, the Title V renewal applications were submitted for Plants Crist, Smith, and Scholz and the Pea Ridge Generating Facility. The final permits for Crist, Smith, and Scholz were issued in December 2009 and the Pea Ridge permit was subsequently issued in March 2010. An application to revise the Plant Crist Title V permit to incorporate new operating conditions for the Crist FGD scrubber was submitted in June, 2010 and was subsequently issued in November, 2010. The initial Title V permit for the Perdido Landfill Gas-to-Energy Facility was issued in March, 2012. An application to revise the Plant Smith Title V permit to incorporate new operating conditions for the Smith Combined Cycle units was submitted in June 2012 and issuance is expected later this year.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $125,044

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.4

Title: Asbestos Fees

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
Asbestos Fees include both annual and individual project fees due to the Florida Department of Environmental Protection (FDEP) for asbestos abatement projects.

Accomplishments:
Fees are paid as required by FDEP.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $900

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.5

Title: Emission Monitoring

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Emission Monitoring program provides quality assurance/quality control testing for Continuous Emission Monitoring systems, including Relative Accuracy Test Audits and Linearity Tests, as required by the Clean Air Act Amendments (CAAA) of 1990.

Accomplishments:
All systems are in compliance.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $645,576

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.6

Title: General Water Quality

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The General Water Quality activities are undertaken pursuant to the Company's NPDES permit, soil contamination studies, dechlorination, surface and groundwater monitoring studies. This line item also includes expenses for Gulf's Cooling Water Intake program, the Impaired Waters Rule, Storm Water Maintenance, and the Impoundment Integrity project.

Accomplishments:
All activities are on-going in compliance with all applicable environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $851,953

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.7

Title: Groundwater Contamination Investigation

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Groundwater Contamination Investigation project includes sampling and testing to determine possible environmental impacts to soil and groundwater from past herbicide applications at various substation sites. Once possible environmental impacts to groundwater and soils have been identified cleanup operations are initiated.

Accomplishments:
The Florida Department of Environmental Protection has issued a No Further Action (NFA) letter or Site Rehabilitation Completion Order for 62 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $2,160,894

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.8

Title: State NPDES Administration

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The State NPDES Administration fees are required by the State of Florida's National Pollutant Discharge Elimination System (NPDES) program administration. Annual and five year permit renewal fees are required for the NPDES industrial wastewater permits at Plants Crist, Smith and Scholz.

Accomplishments:
Gulf has complied with NPDES program administration fee submittal schedule.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $34,500

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.9

Title: Lead & Copper Rule

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The Lead and Copper Rule expenses include potable water treatment and sampling costs as required by the Florida Department of Environmental Protection (FDEP) regulations.

Accomplishments:
Gulf has complied with all sampling and analytical protocols.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $16,480

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.10

Title: Environmental Auditing/Assessment

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Environmental Auditing/Assessment program ensures continued compliance with environmental laws, rules, and regulations through auditing and/or assessment of company facilities and operations.

Accomplishments:
Audits and assessments completed to date have demonstrated compliance with environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $7,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.11

Title: General Solid and Hazardous Waste

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The General Solid and Hazardous Waste program provides for the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes. This line item also includes O&M expenses associated with Gulf's Spill Prevention Control and Countermeasures (SPCC) plan.

Accomplishments:
Gulf has complied with all hazardous and solid waste regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $469,157

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.12

Title: Above Ground Storage Tanks

FPSC Approval: Order No. PSC-97-1047-FOF-EI

Description:
The Above Ground Storage Tank projects are required under the provisions of Chapter 62-762, F.A.C. which includes specific performance standards applicable to storage tank systems. These performance standards include installation of secondary containment and cathodic protection systems as well as periodic tank integrity testing.

Accomplishments:
Gulf has complied with all applicable storage tank requirements.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $186,582

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.13

Title: Low NO_x

FPSC Approval: Order No. PSC-98-0803-FOF-EI

Description:
The Low NO_x activity refers to the maintenance expenses associated with the Low NO_x burner tips on Crist Units 4 & 5 and Smith Unit 1.

Accomplishments:
Burner tips on Plant Crist Units 4 & 5 and Plant Smith Unit 1 have been installed and are in-service.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.14

Title: Ash Pond Diversion Curtains

FPSC Approval: Order No. PSC-98-1764-FOF-EI

Description:
The installation of flow diversion curtains in the Plant Crist ash pond were required to effectively increase water retention time in the ash pond. Diversion curtains allow for the sedimentation/precipitation treatment process to be more effective in reducing levels of suspended particulate from the Plant Crist ash pond outfall.

Accomplishments:
Plant Crist replaced the diversion curtains and dredged the pond during the 2009-2010 timeframe.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $0

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.15

Title: Mercury Emissions

FPSC Approval: Order No. PSC-99-0912-FOF-EI

Description: The Mercury Emissions program pertains to requirements for Gulf to periodically analyze coal shipments for mercury and chlorine content. The Environmental Protection Agency (EPA) mandated that shipments of coal would be analyzed for mercury and chlorine only during 1999. No further notices of continued sampling requirements of coal shipments beyond 1999 have been issued by EPA, therefore no expenses have been planned for this activity.

Accomplishments:
Coal shipments were analyzed as required during 1999. Sampling and analytical requirements are not expected during 2011.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.16

Title: Sodium Injection

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
This line item includes the O&M expenses associated with the sodium injection systems at Plant Smith and Plant Crist. Sodium carbonate is added to the Plant Crist and Plant Smith coal supply to enhance precipitator efficiencies when burning certain low sulfur coals.

Accomplishments:
Sodium carbonate injection is used at Plant Smith and Plant Crist as necessary when low sulfur coal is burned.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $74,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.17

Title: Gulf Coast Ozone Study (GCOS)

FPSC Approval: Order No. PSC-00-0476-FOF-EI

Description:
This project referred to Gulf's participation in the Gulf Coast Ozone Study (GCOS) which was a joint modeling analysis between Gulf Power and the State of Florida to provide an improved basis for assessment of eight-hour ozone air quality for Northwest Florida. The goal of the project was to develop strategies for ozone ambient air attainment to supplement the Florida Department of Environmental Protection (FDEP) studies submitted to the Environmental Protection Agency (EPA) for Escambia and Santa Rosa counties.

Accomplishments: The GCOS project was completed during 2006.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.18

Title: SPCC Substation Project

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
During July 2002 EPA published a revision to Title 40 Code of Regulation Part 112, commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The revision expanded applicability of the rule to include oil containing electrical transformers and regulators, which had previously been excluded from the SPCC regulations. Gulf was required to install additional containment and/or diversionary structures or equipment at several substations to prevent a potential discharge of mineral oil to navigable waters of the United States or adjoining shorelines.

Accomplishments: Gulf has assessed its substations to determine which sites are subject to the revised SPCC regulations. Additional containment has been added to the substations that were identified as having a reasonable risk of discharging oil into navigable waters of the United States or adjoining shorelines.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.19

Title: FDEP NO_x Reduction Agreement

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description: This line item includes the O&M expenses associated with the Crist Unit 6 and Unit 7 SCRs and the Crist Units 4 and 5Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the Florida Department of Environmental Protection (FDEP) and Gulf Power Agreement entered into on August 28, 2002. Anhydrous ammonia, urea, air monitoring, catalyst regeneration, and general operation and maintenance expenses are included in this line item.

Accomplishments: The Crist Unit 6 and Unit 7 SCRs and the Crist Units 4 and5 SNCRs are fully operational. The Crist Unit 6 SNCR was retired when the Crist Unit 6 SCR was placed in-service during the Spring of 2012.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,670,326

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.20

Title: CAIR/CAMR/CAVR Compliance Program

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: This line item includes the O&M expenses associated with the stipulated portions of Gulf's CAIR/CAMR/CAVR Compliance program and the Climate Registry. Immediately after the passage of the EPA's CAIR and CAMR in 2005, Gulf began extensive engineering, design, and other planning activities to determine the most cost effective strategy for compliance with the CAIR, CAMR, and CAVR requirements. On March 29, 2007, Gulf petitioned the Commission for approval of the Company's plan to achieve and maintain compliance with the CAIR, CAMR, and CAVR. On June 22, 2007, the Office of Public Counsel ("OPC"), the Florida Industrial Power Users' Group ("FIPUG") and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's CAIR/CAMR/CAVR Compliance Plan (the "Plan"). That stipulation identified 10 specific components of Gulf's Plan as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the Plan. On August 14, 2007, the Commission voted to approve the stipulation with the provision that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its Plan into which the Company is moving. The approved plan includes a more detailed discussion of the planning process and evaluation utilized by Gulf to select the most reasonable and prudent strategy for compliance with these regulations on a plant and/or unit specific basis.

Accomplishments: The Scholz mercury monitoring system, the first Compliance Plan capital project, was placed in-service during August 2008. The Plant Smith Unit 1 and Unit 2 SNCRs were placed in service during May 2009 and December 2008, respectively. The Crist Units 4 -7 scrubber project was placed in-service December of 2009 and the Crist Unit 6 hydrated lime injection system was placed in-service in 2011. The Plant Crist Unit 6 SCR was placed-in-service in April of 2012. The Crist Unit 6 SNCR was retired when the Crist Unit 6 SCR was placed in-service. Gulf will be incurring O&M expenses associated with these projects during 2013.

Fiscal Expenditures: N/A
Progress Summary: See Accomplishments

Projections: $16,542,564

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.21

Title: Maximum Achievable Control Technology (MACT)
Information Collection Request (ICR)

FPSC Approval: Order No. PSC-09-0759-FOF-EI

Description: During early 2010 EPA finalized an extensive Information Collection Request (ICR) for coal and oil fired steam electric generating units to support Maximum Achievable Control Technology (MACT) rulemaking under Section 112 of the Clean Air Act (CAA). The ICR required submission of information on control equipment efficiencies, emissions, capital and O&M costs, and fuel data for all coal and oil fired generating units greater than 25MW.

Accomplishments:
Gulf completed the Part I & 2 MACT ICR survey and the Part 3 emissions testing reports during 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $0

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2013-December 2013

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.22

Title: Crist Water Conservation

FPSC Approval: Order No. PSC-08-0775-FOF-EI

Description: Gulf Power entered into an agreement with the Emerald Coast Utilities Authority (ECUA) to begin utilizing reclaimed water from ECUA's new wastewater treatment plant to reduce the demand for groundwater and surface water withdrawals. This line item includes general O&M expenses associated with the Plant Crist reclaimed water system such as piping and valve maintenance and pump replacements.

Accomplishments:
Gulfs began receiving reclaimed water from ECUA during November 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $291,840

Schedule 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2013 - December 2013

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Jan - Dec. 2013 Projected Sales at Meter (KWH)	(3) Projected Avg 12 CP at Meter (KW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (KWH)	(7) Projected Avg 12 CP at Generation (KW)	(8) Percentage of KWH Sales at Generation (%)	(9) Percentage of 12 CP Demand at Generation (%)
RS, RSVP	57.312955%	5,445,580,000	1,084,644.04	1.00820508	1.00777864	5,487,939,206	1,093,543.63	48.55616%	57.25855%
GS	63.216034%	282,614,000	51,034.32	1.00820395	1.00777656	284,811,765	51,453.00	2.51996%	2.69411%
GSD, GSDT, GSTOU	73.903822%	2,657,985,000	410,564.62	1.00800263	1.00762887	2,678,262,422	413,850.22	23.69672%	21.66942%
LP, LPT	84.021171%	1,160,741,000	157,703.92	0.97344897	0.98364378	1,141,755,665	153,516.72	10.10202%	8.03822%
PX, PXT, RTP, SBS	94.359108%	1,607,910,000	194,524.27	0.95247952	0.96644352	1,553,954,200	185,280.38	13.74907%	9.70138%
OS-I/II	178.491660%	108,574,000	6,943.91	1.00802086	1.00777465	109,418,125	6,999.61	0.96811%	0.36650%
OS-III	101.451511%	45,752,000	5,148.11	1.00838359	1.00778595	46,108,223	5,191.27	0.40796%	0.27182%
TOTAL		11,309,156,000	1,910,563.19			11,302,249,606	1,909,834.83	100.00000%	100.00000%

Notes:
(1) Average 12 CP load factor based on actual 2009 load research data
(2) Projected KWH sales for the period January 2013 - December 2013
(3) Calculated: (Col 2) / (8,760 x Col 1), (8,760 hours = the # of hours in 1 year)
(4) Based on demand losses identified in Docket No. 110138-EI
(5) Based on energy losses identified in Docket No. 110138-EI
(6) Col 2 x Col 5
(7) Col 3 x Col 4
(8) Col 6 / total for Col 6
(9) Col 7 / total for Col 7

Schedule 7P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2013 - December 2013

Rate Class	(1) Percentage of KWH Sales at Generation (%)	(2) Percentage of 12 CP Demand at Generation (%)	(3) Energy-Related Costs	(4) Demand-Related Costs	(5) Total Environmental Costs	(6) Projected Sales at Meter (KWH)	(7) Environmental Cost Recovery Factors (¢/KWH)
RS, RSVP	48.55616%	57.25855%	63,448,931	4,771,365	68,220,296	5,445,580,000	1.253
GS	2.51996%	2.69411%	3,292,863	224,501	3,517,364	282,614,000	1.245
GSD, GSDT, GSTOU	23.69672%	21.66942%	30,964,795	1,805,717	32,770,512	2,657,985,000	1.233
LP, LPT	10.10202%	8.03822%	13,200,433	669,827	13,870,260	1,160,741,000	1.195
PX, PXT, RTP, SBS	13.74907%	9.70138%	17,966,078	808,418	18,774,496	1,607,910,000	1.168
OS-I, OS-II	0.96811%	0.36650%	1,265,041	30,541	1,295,582	108,574,000	1.193
OS-III	0.40796%	0.27182%	533,086	22,651	555,737	45,752,000	1.215
TOTAL	100.00000%	100.00000%	$130,671,227	$8,333,020	139,004,247	11,309,156,000	1.229

Notes:
(1) From Schedule 6P, Col 8
(2) From Schedule 6P, Col 9
(3) Col 1 x Total Energy $ from Schedule 1P, line 5
(4) Col 2 x Total Demand $ from Schedule 1P, line 5
(5) Col 3 + Col 4
(6) Projected KWH sales for the period January 2013 - December 2013
(7) Col 5 x 100 / Col 6

Schedule 8P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projection Period Amount
January 2013-December 2013

FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	666,447	40.7337	5.03	2.0495	2.0495	
2	Short-Term Debt	29,679	1.8140	0.43	0.0078	0.0078	
3	Preferred Stock	53,354	3.2610	6.33	0.2064	0.3360	
4	Common Stock	618,903	37.8278	10.25	3.8773	6.3123	
5	Customer Deposits	22,133	1.3528	6.25	0.0846	0.0846	
6	Deferred Taxes	242,193	14.8030				
7	Investment Tax Credit	3,398	0.2077	7.50	0.0156	0.0221	
8	Total	1,636,107	100.0000		6.2412	8.8123	0.7344
	ITC Component:						
9	Debt	666,447	49.7830	5.03	2.5048	0.0052	
10	Equity-Preferred	53,354	3.9855	6.33	0.2522	0.0009	
11	-Common	618,903	46.2315	10.25	4.7387	0.0160	
12		1,338,703	100.0000		7.4957	0.0221	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.1471	0.1789
14	Total Equity Component (Lines 3, 4, 10, and 11)					6.6652	0.5555
15	Total Revenue Requirement Rate of Return					8.8123	0.7344

Column:
(1) Based on the May 2012 Surveillance Report, Schedule 4.
(2) Column (1) / Total Column (1)
(3) Based on the May 2012 Surveillance Report, Schedule 4.
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: **Environmental Cost Recovery Clause**)

Docket No.: **120007-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by U. S. mail this 27th day of August, 2012 on the following:

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