INFORMATION COLLECTION REQUEST FOR NATIONAL EMMISION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP) FOR COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Part B of the Supporting Statement

1. Respondent Universe

In 2005, the number of coal- and oil-fired electric utility steam generating facilities owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies included approximately 1,325 units (boilers) that generated greater than 25 megawatts-electric (MWe), according to the U.S. Department of Energy/Energy Information Administration (DOE/EIA) Form EIA-767 database. Currently, this database contains the most recent data available from DOE for coal- and oil-fired electric utility steam generating units but DOE/EIA states that (as of the writing of this supporting statement) that the 2007 database is soon to be made publically available. The 2006 EIA-860 database covers some of the same units covered by EIA-767; however, this database also includes units owned and operated by non-utilities (including independent power producers and combined heat and power producers). EPA will query this database to determine if it includes any coal- or oil-fired electric utility steam generating units that meet the Act's definition. Additionally, EPA/OAR/Office of Air Quality Planning and Standards will coordinate with EPA/OAR/Clean Air Markets Division (to obtain an industry configuration database output from their electric utility sulfur dioxide (SO_2) cap-and trade program) for help with the development of the final list of electric utilities in this survey data collection effort. As facilities respond to the ICR data request, the Agency will modify this base list of units to represent all affected sources under this effort.

2. Selection of Units to Conduct Stack Testing

Coal-fired units to be tested will be selected to cover four potential groupings of hazardous air pollutants (HAP) that may be addressed through the use of surrogates based on current understanding of appropriate surrogates. These potential groupings of HAP are acid-gas HAP (e.g., hydrogen chloride (HCl), hydrogen fluoride (HF)), dioxin/furan organic HAP, non-dioxin/furan organic HAP, and mercury and other non-mercury metallic HAP. For oil-fired units, the bases for any surrogacy argument(s) are less well developed and will require more extensive testing. Rationale for the selection of units for each possible surrogate grouping is

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discussed below. In the following stack testing, each facility is required to test after the last control device or at the stack if the last control device is not shared with one or more other units. In this way, the facility would test before any "dilution" by gases from a separately-controlled unit.

Coal-fired units, acid gas HAP

The acid-gas HAP, HCl and HF, are water-soluble compounds and are more soluble in water than is SO_2. (Hydrogen cyanide, HCN, representing the "cyanide compounds," is also water-soluble and will be considered an "acid-gas HAP" in this document.) HCl also has a large acid dissociation constant (i.e., HCl is a strong acid) and is, thus, will react easily in an acid-base reaction with (i.e., be readily adsorbed on) caustic sorbents (e.g., lime, limestone). This indicates that both HCl and HF will be more rapidly and readily removed from a flue gas stream than will SO_2, even when only plain water is utilized. In the slurry streams, composed of water and sorbent (e.g., lime, limestone) utilized in both wet and dry flue gas desulfurization (FGD) systems, acid gases and SO_2 are absorbed by the slurry mixture and react to (usually) form solid salts. In fluidized bed combustion (FBC) systems, the acid gases and SO_2 are adsorbed by the sorbent (usually limestone) that is added to the coal and an inert material (e.g., sand, silica, alumina, or ash) as part of the FBC process. The adsorption process is temperature dependent and the cooler the flue gas, the more effectively the acid gases will react with the sorbents. One mole of calcium hydroxide ($Ca(OH)_2$) will neutralize one mole of SO_2, whereas one mole of $Ca(OH)_2$ will neutralize two moles of HCl. A similar reaction occurs with the neutralization of HF. These reactions demonstrate that when using a spray dryer, the HCl and HF are removed more readily than is the SO_2. Given that even more water is available in a wet-FGD system, the same condition would also hold in that situation (i.e., in a wet-FGD, HCl and HF would be removed more readily than SO_2). Thus, emissions of SO_2, a commonly measured pollutant, could be used as a surrogate for emissions of the acid-gas HAP HCl and HF. Although this approach has not been used in any section 112 rules by the Agency, it has been used in a number of State permitting actions (e.g., Arkansas/Plum Point; Kentucky/Spurlock 3; Nebraska/Nebraska City 2; Wisconsin/Elm Road-Oak Creek and Weston 4).

However, potential issues have been raised as to whether SO_2 can serve as a legally defensible surrogate for HCl and HF because the subject HAP (i.e., HCl, HF) must be "inherently present" in the potential surrogate (i.e., SO_2), a condition presented by the Court in

Sierra Club v. EPA, January 13, 2004 ("Copper Smelters") and a condition that is not present with this HAP/surrogate group. In addition, there are coal-fired utility boilers that utilize low chlorine content coals and that do not have FGD systems installed. In order to assess whether any of these units could be among the top performing 12 percent of sources on an HCl-emissions basis, it is necessary to identify and test such units.

Based on data obtained through the 1999 ICR, EPA was able to rank-order the coals used by chlorine content. Although there is variation in the coal chlorine content over a year, this methodology, and the number of units selected, will provide a reasonable basis for ensuring that some low-chlorine coal is included in the testing. From this ranking, EPA selected 360 units at 139 facilities with the lowest chlorine content coals. EPA also evaluated coal-fired units with FGD systems installed. Using a tested SO_2 removal efficiency (at the unit's annual operational factor) of 90 percent or greater as a metric and assuming equal or greater HCl/HF/HCN removal, EPA selected 123 units at 78 facilities with the lowest resulting estimated chlorine emissions. Each of the facilities identified as using a low-chlorine coal would be required to test one unit, assuming its use of the common, low-chlorine content coal and not being equipped with any SO_2 controls. Each facility identified with FGD systems installed would be required to test after that specific FGD control (or at the stack if the FGD control device is not shared with one or more other units). If a facility has more than one unit on the FGD control list, the facility would be required to test only one of those FGD controls (or at the stack if the FGD control device is not shared with one or more other units). The facility units identified in the non-FGD portion of Attachment 4 (i.e., low chlorine coal users) would be required to test for HCl, HF, HCN, SO_2, O_2, carbon dioxide (CO_2), and moisture from the stack gases, and chlorine, fluorine, and sulfur content, higher heating value (HHV), and proximate/ultimate analyses of coal being utilized during the test. Similarly, each of the facilities identified as using an FGD system in Attachment 4 would be required to test one unit, assuming use of an FGD system, for HCl, HF, HCN, SO_2, O_2, CO_2, and moisture from the stack gases, and chlorine, fluorine, and sulfur content, HHV, and proximate/ultimate analyses of coal being utilized during the test.

This would yield an additional 217 data sets to be added to the data set from which to determine the top performing 12 percent.

Coal-fired units, dioxin/furan organic HAP

Dioxin data were obtained in support of the 1998 Utility Report to Congress. However, approximately one-half of those data were listed as being below the minimum detection limit for the given test, indicating potential issues with developing an emission limit. Dioxin/furan emissions from coal-fired utility units are generally considered to be low, presumably because of the insufficient amounts of available chlorine. As a result of previous work conducted on municipal waste combustors (MWC), it has also been proposed that the formation of dioxins and furans in exhaust gases is inhibited by the presence of sulfur.[1] Further, it has been suggested that if the sulfur-to-chlorine ratio (S:Cl) is greater than 1.0, then formation of dioxins/furans is inhibited.[2,3] The vast majority of the coal analyses provided through the 1999 ICR indicated S:Cl values greater than 1.0. Based on data obtained through the 1999 ICR, EPA was able to rank-order the coals used by S:Cl value. Again, although there is variation in the S:Cl value over a year, this methodology, and the number of units selected, will provide a reasonable basis for ensuring that some coals with the S:Cl value sought are included in the testing. From this ranking, EPA selected 394 units at 137 facilities (Attachment 5) with S:Cl values less than 5.0 (a value selected to obtain a sufficient number of units in the pool selected for testing). Each of these facilities would be required to test one unit, assuming use of coal with a common S:Cl value, for dioxins/furans, O_2, CO_2, and moisture from the stack gases, and chlorine and sulfur content, HHV, and proximate/ultimate analyses of the coal being utilized during the test.

In addition, as a result of previous work done on MWC units, EPA identified activated carbon as a potential control technology for dioxin/furan control. Therefore, EPA identified 21 units at 12 facilities with activated carbon injection (ACI) systems installed (Attachment 5). Each of these facilities would be required to test one unit, assuming use of ACI and common coal, for dioxins/furans from the stack gases, and chlorine and sulfur content, HHV, and proximate/ultimate analyses of the coal being utilized during the test.

This would yield an additional 149 data sets to be added to the data set from which to determine the top performing 12 percent.

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[1] Gullett, B.K., et al. Effect of Cofiring Coal on Formation of Polychlorinated Dibenzo-*p*-Dioxins and Dibenzofurans during Waste Combustion. *Environmental Science and Technology*. Vol. 34, No. 2:282-290. 2000.
[2] Raghunathan, K., and B,K. Gullett. Role of Sulfur in Reducing PCDD and PCDF Formation. *Environmental Science and Technology*. Vol. 30, No. 6:1827-1834. 1996.
[3] Li., H., et al. Chlorinated Organic Compounds Evolved During the combustion of Blends of Refuse-derived Fuels and Coals. *Journal of Thermal Analysis*. Vol. 49:1417-1422. 1997.

Coal-fired units, non-dioxin/furan organic HAP

Emissions of carbon monoxide (CO), volatile organic compounds (VOC), and/or total hydrocarbons (THC) have been used as surrogates for the non-dioxin/furan organic HAP based on the theory that efficient combustion leads to lower organic emissions.[4] However, there are very few emissions data available for these compounds from coal-fired utility boilers. Further, the HAP/CO surrogacy pairing has the same issue with the Copper Smelter ruling noted earlier for acid gas HAP/SO_2. Therefore, EPA selected those 274 coal-fired units at 184 facilities (Attachment 6) having come on-line since 1980 as being representative of the most modern, and, thus, presumed most efficient, units. Each facility with one of these units would be required to test one unit, assuming the unit came on-line since 1980, for CO, VOC, THC, polycyclic organic matter (POM), NO_x, formaldehyde, methane, O_2, CO_2, and moisture from the stack gases and HHV and proximate/ultimate analyses of the coal being utilized during the test. This would yield an additional 184 data sets to be added to the data set from which to determine the top performing 12 percent.

Coal-fired units, mercury and other non-mercury metallic HAP

Emissions of certain non-mercury metallic HAP (i.e., antimony (Sb), beryllium (Be), cadmium (Cd), cobalt (Co), lead (Pb), manganese (Mn), and nickel (Ni)) have been assumed to be well controlled by particulate matter (PM) control devices. However, mercury (Hg) and other non-mercury metallic HAP (i.e., arsenic (As), chromium (Cr), and selenium (Se)), because of their presence in both particulate and vapor phases, have been reported, in some instances, to be not well controlled by PM control devices. Also, it has been shown through recent stack testing that certain non-mercury metallic HAP (i.e., As, Cr, and Se) tend to condense on (or as) very fine particulate matter in the emissions from coal-fired units. There are very few recent emissions test data available showing the potential control of these metallic HAP from coal-fired utility boilers. (Phosphorus (P) will be considered a "non-mercury metallic HAP" in this document.)

The capture of Hg is dependent on several factors including the chloride content of the coal, the amount of unburned carbon present in the fly ash, the flue gas temperature, and the speciation of the Hg. Based on available data, EPA believes that ACI may be an effective control technology for controlling Hg emissions in coal-fired plants. However, EPA has no

[4] U.S. Environmental Protection Agency. NESHAPS: Final Standards for Hazardous Air Pollutants for Hazardous Waste Combustors; Final Rule. 64 FR 52828. September 30, 1999.

direct stack test results showing how effectively these ACI-equipped plants reduce their Hg emissions.

Finally, coal contains trace quantities of the naturally-occurring radionuclides (e.g., uranium and thorium), as well as their radioactive decay products, and potassium-40. When coal is burned, minerals, including most of the radionuclides, do not burn and concentrate in the ash. Although most of the ash is captured, fly ash including some radionuclides, escape from the boiler into the atmosphere. There is some indication that the radionuclides partition to, or enrich on, the in the fine particulate fraction of coal-fired emissions. The behavior of uranium and the uranium-decay products has been attributed to the fact that uranium typically occurs in coal in different phases and can, therefore, give rise to both volatile and semi-volatile species during combustion. The only available data on radionuclide emissions from coal-fired EGUs is nearly 15 years old.

For these reasons, EPA selected those 214 coal-fired units at 123 facilities with PM controls having come on-line since 1990 as being representative of the most modern PM controlled units as well as units with ACI in use. Although some of the units meet both criteria, some only meet the ACI usage criteria. The units chosen to meet these two criteria have a good potential for control of fine PM, radionuclides, and Hg. These units are shown in Attachment 7.

Each facility in Attachment 7 would be required to test after that specific PM control (or at the stack if the PM control device is not shared with one or more other units). If a facility has more than one unit on the PM control list, the facility would be required to test after each of those PM controls (or at the stack if the PM control device is not shared with one or more other units). There are several facilities that are listed in both the PM and the ACI portion of this list of units. These facilities can test at the control device exit (or at the stack if the PM control device is not shared with one or more other units) as long as the ACI injection occurs before the PM control listed. Therefore, each of these facilities would be required to test the unit listed, and if ACI equipped, assuming use of ACI and common coal, for Sb, As, Be, Cd, Cr, Cr^{+6}, Co, Pb, Mn, Hg, Ni, Se, P, PM (total filterable, fine [dry], fine [wet]), total solids, black carbon, radionuclides, O_2, CO_2, and moisture. All units would also be required to analyze their coal for the metals above (including Hg), P, radionuclides, chlorine, and provide the HHV and proximate/ultimate analyses of the coal being utilized during the test.

This would yield an additional 214 data sets to be added to the data set from which to determine the top performing 12 percent.

Oil-fired units

The potential surrogacy arguments for coal-fired units are primarily based on the use of add-on control technologies, in the case of the non-mercury metallic HAP (PM) and the acid-gas HAP (HCl, HF), or on the S:Cl value for the dioxin/furan organic HAP. However, the data obtained in support of the 1998 Utility Report to Congress and the 2000 Regulatory Determination do not indicate any correlation between PM control and emissions of non-mercury metallic HAP from oil-fired units. Further, no oil-fired unit has a FGD system installed, eliminating the potential basis for the use of emissions of SO_2 as a surrogate for emissions of the acid-gas HAP from such units. In addition, it is not known if the S:Cl value has the same relevance for oil-fired units as it does for coal-fired units. Thus, EPA has no basis for determining which oil-fired units may be the "best performers." Therefore, all units at each facility that are controlled by a fabric filter or an electrostatic precipitator (77 units at 38 facilities) and 1 unit at each facility where all units are controlled by only multiclones or have no PM control (112 units at 39 facilities) in Attachment 8, would be required to test their stack emissions for Sb, As, Be, Cd, Cr, Cr^{+6}, Co, Pb, Mn, Hg, Ni, Se, P, PM (total filterable, fine [dry], fine [wet]), black carbon, radionuclides, HCl, HF, HCN, SO_2, dioxins/furans, CO, VOC, THC, POM, NO_x, formaldehyde, methane, O_2, CO_2, and moisture. All units would be required to sample their oil for the metals (including Hg), P, radionuclides, chlorine, fluorine, sulfur, and provide HHV and proximate/ultimate analyses of the oil being utilized during the test.

3. Response Rates

Since the information will be requested pursuant to the authority of CAA section 114, EPA expects that all respondents requested to submit information will do so.

Attachment 1.

Draft Questionnaire Content

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Approval Expires __/__/__

ELECTRIC UTILITY STEAM GENERATING UNIT

HAZARDOUS AIR POLLUTANT EMISSIONS INFORMATION COLLECTION EFFORT

BURDEN STATEMENT

Preliminary estimates of the public burden associated with this information collection effort indicate a total of 100,370 hours and $104,807,458. This is the estimated burden for 555 facilities to provide information on their boilers, fuel oil types and/or coal rank, 1,325 units to provide hazardous air pollutant (HAP) emission data and 12 months of fuel analyses, and 880 units to conduct emissions testing.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information that is sent to ten or more persons unless it displays a currently valid Office of Management and Budget (OMB) control number.

GENERAL INSTRUCTIONS

[NOTE: It is EPA's intent for the final version of this questionnaire to be in electronic format. The final format will include all questions noted herein.]

Please provide the information requested in the following forms. If you are unable to respond to an item as it is stated, please provide any information you believe may be related. Use additional copies of the request forms for your response.

If you believe the disclosure of the information requested would compromise confidential business information (CBI) or a trade secret, clearly identify such information as discussed in the cover letter. Any information subsequently determined to constitute CBI or a trade secret under EPA's CBI regulations at 40 CFR part 2, subpart B, will be protected pursuant to those regulations and, for trade secrets, under 18 U.S.C. 1905. If no claim of confidentiality

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accompanies the information when it is received by EPA, it may be made available to the public by EPA without further notice pursuant to EPA regulations at 40 CFR 2.203. Because Clean Air Act (CAA) section 114(c) exempts emission data from claims of confidentiality, the emission data you provide may be made available to the public notwithstanding any claims of confidentiality. A definition of what the EPA considers emissions data is provided in 40 CFR 2.301(a)(2)(i).

The following section is to be completed by all facilities:

- Part I - General Facility Information: once for each facility. A copy of Part I should be completed and returned to the address noted below within 60 days of receipt.

The following section is to be completed by all facilities meeting the section 112(a)(8) definition of an electric utility steam generating unit:

- Part II - Fuel Analyses and Emission Data: Additional copies of certain pages may be necessary for a complete response. A copy of Part II responses should be completed and returned to the address noted below within 60 days of receipt.

The following section is to be completed by all facilities selected for stack testing:

- Part III – Emissions Test Data: One emissions test (consisting of three runs). A copy of the emissions test report should be completed and returned to the address noted below within 6 months of receipt.

Detailed instructions for each part follow.

Questions regarding this information request should be directed to Mr. Bill Maxwell at (919) 541-5430.

Return this information request and any additional information to:

Sector Policies and Programs Division (Mail Code D205-01)
U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

Attention: Peter Tsirigotis, Director

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12. For each boiler noted in Part I, question 15, provide the following information:

Boiler ID	Emissions test results (Indicate format of emission data)[36]							
	Date of test	PM[37]	SO_2	HCl/HF/HCN	Metal HAP[38]	Hg[39]	CO	Other organics (specify)

[36] Provide emission test data for all tests conducted since January 1, 2004. Please include test data acquired both before and after any control device. Use additional pages as necessary. EPA may, at some future date, request a copy of one or more emission test reports. Data generated to fulfill both Federal and State requirements must be provided. Note that data generated pursuant to CAA Title V must be maintained and available for 5 years.

[37] If emission testing recorded the emissions of filterable and condensable PM, separately, please include those separate emission results. Also, please include separate emission results for total PM, PM_{10}, and $PM_{2.5}$.

[38] Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus radionuclides, and selenium; indicate emission level for all metal HAP for which an emission test has been conducted.

[39] Please provide separate results for total Hg, elemental Hg, oxidized Hg, and particulate Hg, as available. If the emissions testing recorded the amount of unburned carbon in fly ash (as reflected by the "Loss of Ignition" [L.O.I.]) at the time of any Hg testing, please include these data.

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PART III: EMISSION TESTING

For units identified in Part B of the Supporting Statement, testing is to be performed for the identified HAP on a one-time basis after the last control device (i.e., after the last control device or at the stack if the last control device is not shared with one or more other units). Facilities are to use the test procedures noted in Enclosure 1 ("Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Procedures, Methods, and Reporting Requirements") for both the stack and fuel sampling. Each test is to consist of three separate runs at the sampling location. EPA requires that the facility conduct paired trains for the fine particulate matter testing (which is included in the testing of units for mercury and other non-mercury metallic HAP) and duplicate trains for the other HAP being tested. Emission measurements frequently consist of a sequential set (typically three) of singular method tests over the course of several hours or days. In contrast, a sequential set of duplicate or paired method tests provides the only measure of test method precision, thereby facilitating identification of test data "outliers" occasionally generated through improper test method execution, versus true source emission variability. Indeed, paired method data provides a quantifiable way to identify and distinguish between erratic test data and actual emission variations. EPA is considering requiring testing twice within the test period to account for variability in emissions testing.

Enclosure 1

Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Procedures, Methods, and Reporting Requirements

This document provides an overview of approved methods, target pollutant units of measure, and reporting requirements for the coal- and oil-fired electric utility steam generating unit test plan. The document is organized as follows:

1.0 Stack Testing Procedures and Methods
2.0 Fuel Analysis Procedures and Methods
3.0 How to Report Data
4.0 How to Submit Data
5.0 Definitions
6.0 Contact Information for Questions on Test Plan and Reporting

1.0 Stack Testing Procedures and Methods

The EPA coal- and oil-fired electric utility steam generating unit test program includes stack test data requests for several pollutants, including specific hazardous air pollutants (HAP) and potential surrogate groups. If you operate a coal- or oil-fired electric utility steam generating unit, you were selected to perform a stack test for some combination of the following pollutants or potential surrogate groups:

- Non-dioxin/furan organic HAP: Carbon monoxide (CO), total hydrocarbons (THC), volatile organic compounds (VOC); polycyclic organic matter (POM), methane, formaldehyde, oxygen (O_2), carbon dioxide (CO_2), oxides of nitrogen (NO_X), volatile and semi-volatile organic HAP
- Dioxin/furan: dioxins/furans (D/F), O_2, CO_2
- Acid gas HAP: hydrogen chloride (HCl), hydrogen fluoride (HF), hydrogen cyanide (HCN), sulfur dioxide (SO_2), O_2, CO_2
- Mercury and non-mercury metallic HAP: mercury (Hg), HAP metals (including antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), Cr^{+6}, cobalt (Co), lead (Pb), manganese (Mn), nickel (Ni), phosphorus (P) and selenium (Se)), radionuclides, particulate matter (PM – total filterable, $PM_{2.5}$ (wet and dry), and condensable); total solids; carbon (black, elemental, organic), O_2, CO_2

Refer to Table _ on page _ of the section 114 letter you received for the specific combustion unit and pollutants we are requesting that you perform emission tests. You may have submitted test data for some of these pollutants already.

1.1 How to Select Sample Location and Gas Composition Analysis Methods

U.S. EPA Method 1 of Appendix A of Part 60 must be used to select the locations and number of traverse points for sampling. See http://www.epa.gov/ttn/emc/methods/method1.html for a copy of the method and guidance information.

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Analysis of flue gas composition, including oxygen concentration, must be performed using U.S. EPA Methods 3A or 3B of Appendix A of Part 60. See http://www.epa.gov/ttn/emc/methods/method3a.html for Method 3A or http://www.epa.gov/ttn/emc/methods/method3b.html for Method 3B information.

1.2 Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Reporting

Table 1.2 presents a summary of the recommended test methods for each pollutant and possible alternative methods. If you would like to use a method not on this list, and the list does not meet the definition of "equivalent" provided in the definitions section of this document, please contact EPA for approval of an alternative method.

For copies of the recommended U.S. EPA methods and additional information, please refer to EPA's Emission Measurement Center website: http://www.epa.gov/ttn/emc/. A copy of RCRA Method 0011 for aldehydes may be obtained here: http://www.epa.gov/epawaste/hazard/testmethods/sw846/pdfs/0011.pdf.

Report pollutant emission data as specified in Table 1.2 below. Each test should be comprised of three test runs. All pollutant concentrations should be corrected to 7 percent oxygen and should be reported on the same moisture basis. Report the results of the stack tests according to the instructions in Section 3.0 of this enclosure. In addition to the emission test data, you should also report the following process information taken during the 30 day period before, at the time of, and during, the emissions test: Heat input; fuel composition and feed rate; steam output; emissions control devices in use during the test; control device operating or monitoring parameters (including, as appropriate to the control device, flue gas flow rate, pressure drop, scrubber liquor pH, scrubber liquor flow rate, sorbent type and sorbent injection rate), and process parameters (such as oxygen).

Table 1.2: Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Alternative Methods

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
CO	U.S. EPA Method 10, 10A, or 10B	None	ppmvd @ 7% O_2
Formaldehyde	U.S. EPA Method 320 with a minimum sample time of 1 hour per run.	RCRA Method 0011. Collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 2 hours per run.	ppmvd @ 7% O_2
HCl and HF	U.S. EPA Method 26A	U.S. EPA Method 26 if there are no entrained water droplets in the sample or U.S. EPA Method 320.	lb/MMBtu

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Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
HCN	U.S. EPA Conditional Test Method 033 (CTM-033)	U.S. EPA Method 26A combined with the analysis procedures from CTM-033, U.S. EPA Method 320, or U.S. EPA Method 26 combined with the analysis procedures from CTM-033, U.S. EPA Method 320 if there are no entrained water droplets in the sample.	lb/MMBtu
Hg	ASTM-D6784-02 (Ontario Hydro Method). Collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 2 hours per run.	U.S. EPA Method 29* or U.S. EPA Method 30B.	lb/MMBtu
Cr^{+6}	U.S. EPA SW-846 Method 0061	U.S. EPA Method 29*. Report all Cr as Cr^{+6}.	lb/MMBtu
Metals	U.S. EPA Method 29** No permanganate solution needed, if Hg will not be measured. Collect a minimum volume of 4.0 cubic meters or have a minimum sample time of 4 hours per run. Determine total filterable PM emissions according to §8.3.1.1. Use IC(A)P/MS for the analytical finish. Report all metals results, and report all Cr as Cr^{+6}.	None	lb/MMBtu
Radionuclides	U.S. EPA Method 114. Conduct on digestate of front half filter and on back half of Method 29	None	Microcuries/dry standard cubic meter
$PM_{2.5}$ from stacks without entrained water droplets (e.g., not from units with wet scrubbers)	U.S. EPA Other Test Method 27 (OTM 27) (include cyclone catch***)	None	lb/MMBtu
Black Carbon (BC), elemental carbon (EC), and organic carbon (OC)	Analysis by Magee Scientific Model OT21 – take sample from M201A or M5 filter post gravimetric determination AND IMPROVE_A Thermal/Optical Carbon Analysis		lb/MMBtu for BC, EC, and OC

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Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
$PM_{2.5}$ from stacks with entrained water droplets AND Total Dissolved Solids (TDS) and Total Suspended Solids (TSS) from wet scrubber recirculation liquid	U.S. EPA Method 5 with a filter temperature of 320°F +/- 25°F AND ASTM D5907	For TDS and TSS, Standard Methods of the Examination of Water and Wastewater Method 2540B for solids in scrubber recirculation liquid	lb/MMBtu for PM; AND mg solids liter of scrubber recirculation liquid****
PM (condensable)	U.S. EPA Other Test Method 28 (OTM 28)	None	lb/MMBtu
THC	U.S. EPA Method 25A with a minimum sampling time of one hour per run. Calibrate the measuring instrument with a mixture of the organic compounds being emitted or with propane.	None	ppmvd @ 7% O2
CH_4	U.S. EPA Method 18. Have a minimum sample time of 1 hour per run.	U.S. EPA Method 320.	ppmvd @ 7% O2
D/F, PCB*****	U.S. EPA Method 23. Collect a minimum volume of 10 cubic meters or have a minimum sample time of 8 hours per run. Use high resolution GCMS for the analytical finish.	None	ng/dscm @ 7% O2
Speciated Volatile Organic HAP	U.S. EPA Method 0031with SW-846 Method 8260B. Collect a minimum volume of 10 cubic meters or have a minimum sample time of 8 hours per run.	None	µg/dscm @ 7% O2
Speciated Semi-volatile Organic HAP	U.S. EPA Method 0010 with SW-846 Method 8270D. Collect a minimum volume of 10 cubic meters or have a minimum sample time of 8 hours per run. Use high resolution GCMS for the analytical finish.	None	µg/dscm @ 7% O2
NO_x******	U.S. EPA Method 7E	U.S. EPA Method 7, 7A, 7B, 7C, or 7D	ppmvd @ 7% O_2
SO_2******	U.S. EPA Method 6C	U.S. EPA Method 6	ppmvd @ 7% O_2
O_2/CO_2	U.S. EPA Method 3A	U.S. EPA Method 3B	%
Moisture	U.S. EPA Method 4	None	%

*Method 29 in appendix A-8 to part 60 of this chapter can also be used for Hg, but follow the procedures for preparation of Hg standards and sample analysis in sections 13.4.1.1 through 13.4.1.3 of ASTM D6784-02 instead of the procedures in sections 7.5.33 and 11.1.3 of Method 29, and perform the QA/QC procedures in section 13.4.2 of ASTM D6784-02 instead of the procedures in section 9.2.3 of Method 29. The tester may also opt to use the sample recovery and preparation procedures in ASTM D6784-02 instead of the Method 29 procedures, as follows:

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sections 8.2.8 and 8.2.9.1 of Method 29 can be replaced with sections 13.2.9.1 through 13.2.9.3 of ASTM D6784-02; sections 8.2.9.2 and 8.2.9.3 of Method 29 can be replaced with sections 13.2.10.1 through 13.2.10.4 of ASTM D6784-02; section 8.3.4 of Method 29 can be replaced with section 13.3.4 or 13.3.6 of ASTM D6784-02 (as appropriate); and section 8.3.5 of Method 29 can be replaced with section 13.3.5 or 13.3.6 of ASTM D6784-02 (as appropriate).

If both mercury and other metals will be testing using EPA Method 29, the stack test company should be diligent in the set-up and handling of the impingers to avoid cross contamination of the manganese from the permanganate into the metals catch. Alternately, the contractor may want to collect mercury on a separate train from the train used to collect the other metals.

**If both mercury and other metals will be testing using EPA Method 29, the stack test company should be diligent in the set-up and handling of the impingers to avoid cross contamination of the manganese from the permanganate into the metals catch. Alternately, the contractor may want to collect mercury on a separate train from the train used to collect the other metals.

***PM filterable is determined by including the cyclone catch.

****Also report scrubber recirculation liquid flow rate in liters/min and fuel feed rate in MMBTU/hr.

*****Just the 12 "dioxin-like" PCB congeners (see the WHO PCB Congener List)

******If a combustion unit has CEMS installed for CO, NO_x and/or SO_2, the unit can report daily averages from 30 days of CEMS data in lieu of conducting a CO, NO_x and/or SO_2 stack test. In order to correlate these emissions with other stack test emissions, a portion of the CEMS data should contain emissions data collected during performance of the other requested stack tests. The CEMS must meet the requirements of the applicable Performance Specification: CO – Performance Specification 4; NO_x and SO_2 – Performance Specification 2.

2.0 Fuel Analysis Procedures and Methods

The EPA coal- and oil-fired electric utility steam generating unit test program is requesting fuel variability data for fuel-based HAP. The fuel analyses requested include: mercury, chlorine, fluorine, and metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium) for any coal- and oil-fired electric utility steam generating unit that is selected to conduct a stack test.

You will need to conduct one fuel sample (comprised of three composite samples, each individually analyzed) of the fuel used during the stack test (one composite sample per test run).

Refer to page 1 of the Section 114 letter you received for the specific types of fuel analyses we are requesting from your facility. Directions for collecting, compositing, preparing, and analyzing fuel analysis data are outlined in Sections 2.1 through 2.4.

2.1 How to Collect a Fuel Sample

Table 2.1 outlines a summary of how samples should be collected. Alternately, you may use the procedures in ASTM D2234–00 (for coal) to collect the sample.

Table 2.1: Summary of Sample Collection Procedures

Sampling Location	Sampling Procedures	Sample Collection Timing
	Solid Fuels	
Belt or Screw Feeder	Stop the belt and withdraw a 6- inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag for further processing as specified in Sections 2.2 through 2.5 of this document.	Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.
Fuel Pile or Truck	For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile. At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling. Transfer all samples to a clean plastic bag for further processing as specified in Sections 2.2 through 2.5 of this document.	
	Liquid Fuels	
Manual Sampling	Follow collection methods outlined in ASTM D 4057	
Automatic Sampling	Follow collection methods outlined in ASTM D4177	

Sampling Location	Sampling Procedures	Sample Collection Timing
	Fuel Supplier Analysis	
Fuel Supplier	If you will be using fuel analysis from a fuel supplier in lieu of site specific sampling and analysis, the fuel supplier must collect the sample as specified above and prepare the sample according to methods specified in Sections 2.2 through 2.5 of this document.	

2.2 Create a Composite Sample for Solid Fuels

Follow the seven steps listed below to composite each sample:

(1) Thoroughly mix and pour the entire composite sample over a clean plastic sheet.
(2) Break sample pieces larger than 3 inches into smaller sizes.
(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.
(4) Separate one of the quarter samples as the first subset.
(5) If this subset is too large for grinding, repeat step 3 with the quarter sample and obtain a one-quarter subset from this sample.
(6) Grind the sample in a mill according to ASTM E829-94, or for selenium sampling according to SW-846-7740.
(7) Use the procedure in step 3 of this section to obtain a one quarter subsample for analysis. If the quarter sample is too large, subdivide it further using step 3.

2.3 Prepare Sample for Analysis

Use the methods listed in Table 2.2 to prepare your composite samples for analysis.

Table 2.2: Methods for Preparing Composite Samples

Fuel Type	Method
Solid	SW-846-3050B or EPA 3050 for total selected metal preparation
Liquid	SW-846-3020A or any SW-846 sample digestion procedures giving measures of total metal
Coal	ASTM D2013-04
Biomass	ASTM D5198-92 (2003) or equivalent, EPA 3050, or TAPPI T266 for total selected metal preparation

2.4 Analyzing Fuel Sample

Table 2.3 outlines a list of approved methods for analyzing fuel samplings. If you would like to use a method not on this list, and the list does not meet the definition of "equivalent" provided in Section 5 of this document, please contact EPA for approval of an alternative method.

Table 2.3: List of Analytical Methods for Fuel Analysis

Analyte	Fuel Type	Method	Target Reported Units of Measure
Higher Heating Value	Coal	ASTM D5865–04, ASTM D240, ASTM E711-87 (1996)	
	Biomass	ASTM E711–87 (1996) or equivalent, ASTM D240, or ASTM D5865-04	
	Other Solids	ASTM-5865-03a, ASTM D240, ASTM E711-87 (1997)	
	Liquid	ASTM-5865-03a, ASTM D240, ASTM E711-87 (1996)	Btu/lb
Moisture	Coal, Biomass, Other Solids	ASTM-D3 173-03, ASTM E871-82 (1998) or equivalent, EPA 160.3 Mod., or ASTM D2691-95 for coal.	%
Mercury Concentration	Coal	ASTM D6722-01, EPA Method 1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	
	Biomass	SW-846-7471A, EPA Method 1631E, SW-846-1631, ASTM D6722-01, EPA 821-R-01-013, or equivalent	
	Other Solids	SW-846-7471A, EPA Method 1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	ppm
	Liquid	SW-846-7470A, EPA Method 1631E, SW-846-1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	
Total Selected Metals Concentration	Coal	SW-846-6010B, ASTM D3683-94 (2000), SW-846-6020, -6020A or ASTM D6357-04 (for arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel in coal)	ppm
		ASTM D4606-03 or SW-846-7740 (for Se)	
		SW-846-7060 or 7060A (for As)	
	Biomass	SW-846-6010B, ASTM D6357-04, SW-846-6020, -6020A, EPA 200.8, or ASTM E885-88 (1996) or equivalent, SW-846-7740 (for Se)	
		SW-846-7060 or -7060A (for As)	
	Other Solids	SW-846-6010B, EPA 200.8	
		SW-846-7060 or 7060A for As	
	Liquid	SW-846-6020, -6020A, , SW-846-6010B, SW-846-7740 for Se, SW-846-7060 or -7060A for As	
Chlorine Concentration	Coal	SW-846-9250 or ASTM D6721-01 or equivalent, SW-846-5050, -9056, -9076, or -9250, ASTM E776-87 (1996)	
	Biomass, Other Solids, Liquids	ASTM E776-87 (1996), SW-846-9250, SW-846-5050, -9056, -9076, or -9250	ppm
Fluorine Concentration	Coal	ASTM D3761-96(2002), D5987-96 (2002)	ppm

Report the results of your fuel analysis according to the directions provided in section 3.0 of this enclosure.

3.0 How to Report Data

The method for reporting the results of any testing and monitoring requests depend on the type of tests and the type of methods used to complete the test requirements. This section discusses the requirements for reporting the data.

3.1 Reporting stack test data

If you conducted a stack test using one of the methods listed in Table 3.1, (Method 6C, Method 7E, Method 10, Method 17, Method 25A, Method 26A, Method 29, Method 101, Method 101A, Method 201A, Method 202) you must report your data using the EPA Electronic Reporting Tool (ERT) Version 3. At present, only these methods are supported by the ERT. ERT is a Microsoft ® Access database application. Two versions of the ERT application are available. If you are not a registered owner of Microsoft ® Access, you can install the runtime version of the ERT Application. Both versions of the ERT are available at http://www.epa.gov/ttn/chief/ert/ert_tool.html. The ERT supports an Excel spreadsheet application (which is included in the files downloaded with the ERT) to document the collection of the field sampling data. After completing the ERT, will also need to attach an electronic copy of the emission test report (PDF format preferred) to the Attachments module of the ERT.

Table 3.1: List of Test Methods Supported by ERT

Test Methods Supported by ERT
Methods 1 through 4
Method 7E
Method 6C
Method 5
Method 3A
Method 29
Method 26A
Method 25A
Method 202
Method 201A
Method 17
Method 101A
Method 101
Method 10
CT Method 40
CT Method 39

If you conducted a stack test using a method not currently supported by the ERT, you must report the results of this test in a Microsoft ® Excel Emission Test Template. The Excel templates are specific to each pollutant and type of unit and they can be downloaded from {*to be added later*}. You must report the results of each test on appropriately labeled worksheet corresponding to the specific tests requested at your combustion unit. If more than one unit at your facility conducted a stack test using methods not currently supported by the ERT, you must make a copy of the worksheet and update the combustor ID in order to distinguish between each

separate test. After completing the worksheet, you must also submit an electronic copy of the emission test report (PDF format preferred).

If you have CO CEMS that meets performance specification-4 or a SO_2 and/or NO_x CEMS that meets performance specification-2 installed at your combustion unit, and you used CEMS data to meet CO, SO_2 and/or NO_x test requirements at your facility, you must report daily averages from 30 days of CEMS data in a Microsoft ® Excel CEMS Template. The Excel templates are specific to each pollutant and type of unit and they can be downloaded from {*to be added later*}.

3.2 Reporting Fuel Analysis Data

If you conducted a fuel analysis, you must report the analysis results separately for each of the 12 samples in a Microsoft ® Excel Fuel Analysis Template. The fuel samples collected in conjunction with the stack test are comprised of three composite samples, each of which is analyzed separately. The remaining nine additional fuel samples are also comprised of three composite samples, but only the combined composite samples are analyzed. The Excel template can be downloaded from {*to be added later*}. If you conducted fuel analysis on more than one type of fuel used during testing, or for more than one combustion unit, you must make a copy of the worksheet and update the combustor ID and fuel type in each worksheet order to distinguish between the separate fuel analyses.

3.3 Required Fields for ERT Reporting

This section outlines the required data entry fields for the ERT in order to satisfy the requirements of this ICR test program. Appendix A {*to be provided later*} lists each field within the ERT and notes whether or not the field is required or optional.

4.0 How to Submit Data

You may submit your data in one of three ways as listed below. However, in order to avoid duplicate data and keep all data for a particular facility together, we request that you submit all of the data requested from your facility in the same way. To submit your data:

- E-mail an electronic copy of all requested files to {*to be added later*}
- If the files are too large for your e-mail system, you may upload the electronic files to a FTP site (see directions for FTP site procedures below)
- Mail a CD or DVD containing an electronic copy of all requested files to the EPA address shown in your Section 114 letter. If no electronic copy is available, mail a hard copy of all requested files to the EPA address shown in your Section 114 letter.
- If you are submitting Confidential Business Information (CBI), you must mail a separate CD or DVD containing only the CBI portion of your data to the EPA address shown in your Section 114 letter.

The steps below outline how to upload files to the FTP site by using "My Computer" as well as by using a FTP Client software.

Directions for accessing the FTP site via "My Computer"...

{*To be added later*}

5.0 Definitions

The following definitions apply to the coal- and oil-fired electric utility steam generating unit test plan methods:

Equivalent means:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.
(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.
(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.
(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.
(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.
(6) An equivalent pollutant (mercury, TSM, or total chlorine) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in this test plan.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. States, such as California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, such as Department of Defense (DOD) and Department of Transportation (DOT).

This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

6.0 Contact Information for Questions on Test Plan and Reporting

For questions on how to report data using the ERT, contact:
Ron Myers
U.S. EPA
(919) 541-5407
myers.ron@epa.gov

or

Barrett Parker
U.S. EPA
(919) 541-5635
parker.barrett@epa.gov

For questions on the test methods contact:
Peter Westlin
U.S. EPA
(919) 541-1058
westlin.peter@epa.gov

OR

Gary McAlister
U.S. EPA
(919) 541-1062
mcalister.gary@epa.gov

For questions on the coal- and oil-fired electric utility steam generating unit test plan, including units selected to test and reporting mechanisms other than the ERT, contact:
William Maxwell
U.S. EPA
(919) 541-5430
maxwell.bill@epa.gov

For questions on uploading files to the FTP site, contact:
{To be provided later.}

Attachment 4.

List of coal-fired electric utility steam generating units selected for HCl/HF/HCN acid gas HAP testing

State	Facility Name	Coal rank	No. units	Scrubber
WI	J. P. Madgett	Subbituminous	1	N
MN	Black Dog Generating Plant	Subbituminous	2	N
KS	Tecumseh	Subbituminous; Bituminous	2	N
MO	Lake Road Plant	Subbituminous	1	N
WI	Columbia	Subbituminous	2	N
OK	Sooner	Subbituminous	2	N
NE	Lon Wright	Subbituminous	1	N
IA	Burlington	Subbituminous	1	N
MO	Thomas Hill	Subbituminous	3	N
OK	Muskogee	Subbituminous	3	N
OK	Northeastern	Subbituminous	2	N
TX	Coleto Creek	Subbituminous; Bituminous	1	N
KS	Nearman Creek	Subbituminous	1	N
MN	Laskin Energy Center	Subbituminous	2	N
NE	Gerald Gentleman Station	Subbituminous	2	N
AR	Flint Creek	Subbituminous	1	N
TX	Welsh	Subbituminous	3	N
MO	Labadie	Subbituminous	4	N
LA	Big Cajun 2	Subbituminous	3	N
MN	Clay Boswell Energy Center	Subbituminous	4	N
SD	Big Stone	Subbituminous	1	N
IA	Prairie Creek	Subbituminous	2	N
MO	Sibley	Subbituminous; Bituminous	3	N
MT	J. E. Corette	Subbituminous	1	N
KS	Quindaro	Subbituminous	2	N
NE	Sheldon	Subbituminous; Bituminous	2	N
IA	Riverside	Subbituminous	1	N
IA	Ottumwa	Subbituminous	1	N
MI	Belle River Power Plant	Subbituminous	2	N
IA	George Neal South	Subbituminous	1	N
IA	Ames Electric Services Power Plant	Subbituminous	2	N
WI	Edgewater	Subbituminous	3	N
MO	Rush Island	Subbituminous	2	N
IA	Council Bluffs (Walter Scott, Jr.)	Subbituminous	4	N
AR	Independence	Subbituminous	2	N
WI	Pulliam	Subbituminous	6	N
IA	George Neal North	Subbituminous	3	N
IN	State Line	Subbituminous	2	N
MN	Hoot Lake	Subbituminous	2	N
AZ	Irvington	Bituminous; Subbituminous	1	N
CO	Martin Drake	Subbituminous	2	N
CO	Ray D. Nixon	Subbituminous	1	N
MO	New Madrid	Subbituminous	2	N
MI	Presque Isle	Subbituminous	7	N
AR	White Bluff	Subbituminous	2	N
IL	Waukegan	Subbituminous	3	N
IL	Will County	Subbituminous; Bituminous	4	N

State	Facility Name	Coal rank	No. units	Scrubber
WY	Naughton	Subbituminous	3	N
IL	Joliet 29	Subbituminous	4	N
IL	Havana	Bituminous	1	N
TX	J. T. Deely	Subbituminous	2	N
OR	Boardman	Subbituminous; Bituminous	1	N
IL	Newton	Subbituminous; Bituminous	2	N
IL	Fisk	Subbituminous	1	N
IL	Joliet 9	Subbituminous	1	N
IA	Sutherland	Subbituminous	3	N
IL	Crawford	Subbituminous	2	N
IL	Powerton	Subbituminous; Bituminous	4	N
OH	Bay Shore	Subbituminous;Bituminous	3	N
KY	Pineville	Bituminous	1	N
IN	Michigan City	Subbituminous; Bituminous	1	N
IN	Dean H. Mitchell	Bituminous - Low Sulfur	4	N
LA	Rodemacher Power Station Unit #2	Subbituminous	1	N
TN	John Sevier Fossil Plant	Bituminous	4	N
MS	Victor J. Daniel, Jr.	Subbituminous; Bituminous	2	N
ND	R. M. Heskett Station	Lignite	1	N
IL	Hutsonville	Bituminous	2	N
IL	Kincaid Generation L.L.C.	Subbituminous; Bituminous	2	N
MO	Sikeston Power Station	Subbituminous	1	N
AL	James H. Miller, Jr.	Subbituminous; Bituminous	4	N
ND	Leland Olds Station	Lignite	2	N
IN	Warrick Power Plant	Bituminous - High Sulfur	1	N
NE	Whelan Energy Center	Subbituminous	1	N
OK	Hugo	Subbituminous	1	N
NE	Nebraska City	Subbituminous; Bituminous	1	N
OH	Richard H. Gorsuch	Bituminous	4	N
WI	Weston	Subbituminous	3	N
NE	Platte	Subbituminous	1	N
WY	Dave Johnston	Subbituminous	4	N
MA	Salem Harbor	Bituminous	3	N
IL	Joppa Steam	Subbituminous	6	N
WI	Bay Front Plant Generating	Bituminous	1	N
TX	Monticello	Lignite; Subbituminous	3	N
NE	North Omaha	Subbituminous	5	N
GA	Kraft	Bituminous	3	N
TX	W. A. Parish	Subbituminous	4	N
MO	Southwest Power Station	Subbituminous	1	N
AL	E. C. Gaston	Bituminous	5	N
UT	Carbon	Bituminous	2	N
OH	Picway	Bituminous	1	N
KY	Henderson 1	Bituminous	1	N
KY	Green River	Bituminous	2	N
GA	Mitchell	Bituminous	1	N
TX	Sam Seymour	Subbituminous	3	N
GA	Yates	Bituminous	7	N
IN	Frank E. Ratts	Bituminous	2	N
MI	St. Clair Power Plant	Bituminous; Subbituminous	6	N
TX	Big Brown	Lignite	2	N
GA	Scherer	Subbituminous; Bituminous	4	N

Attachment 5.

List of coal-fired electric utility steam generating units selected for dioxin/furan organic HAP testing

State	Facility Name	Coal rank	No. units	Equipped with ACI
KY	William C. Dale	Bituminous	4	
VA	Cogentrix of Richmond	Bituminous	8	
MI	J. H. Campbell	Bituminous; Subbituminous	3	
KS	Holcomb	Subbituminous	1	
VA	Bremo Power Station	Bituminous	2	
FL	Central Power and Lime, Inc.	Bituminous	1	
KY	H. L. Spurlock	Bituminous	3	
GA	Wansley	Bituminous	2	
FL	Crist	Bituminous	4	
TX	Gibbons Creek	Subbituminous	1	
FL	F. J. Gannon	Bituminous	6	
NC	Roxboro	Bituminous	6	
MS	Jack Watson	Bituminous	2	
TX	Sam Seymour	Subbituminous	3	
UT	Bonanza	Bituminous	1	
MI	J. C. Weadock	Subbituminous; Bituminous	2	
MO	James River Power Station	Bituminous; Subbituminous	3	
IA	Earl F. Wisdom	Bituminous	1	
OH	Lake Shore	Bituminous	1	
AL	Barry	Bituminous	5	
NC	G. G. Allen	Bituminous	5	
FL	Big Bend	Bituminous; Subbituminous	4	
FL	Polk Power	Subbituminous	IGCC	
NC	Cliffside	Bituminous	5	
MA	Somerset	Bituminous	1	
TN	Johnsonville Fossil Plant	Bituminous	10	
NC	Cape Fear	Bituminous	2	
NC	Tobaccoville Utility Plant	Bituminous	2	
KY	Ghent	Bituminous; Subbituminous	4	
OH	Kyger Creek	Bituminous	5	
OH	Miami Fort Station	Bituminous	5	
AL	Greene County	Bituminous	2	
FL	Lansing Smith	Bituminous	2	
CO	Arapahoe	Subbituminous	2	
MN	Silver Lake	Bituminous	1	
SC	W. S. Lee	Bituminous	3	
AL	Charles R. Lowman	Bituminous	3	
KY	John S. Cooper	Bituminous	2	
KY	Shawnee Fossil Plant	Bituminous; Subbituminous	10	
IL	Meredosia	Bituminous	5	

State	Facility Name	Coal rank	No. units	Equipped with ACI
WV	Mountaineer	Bituminous	1	
OH	Muskingum River	Bituminous	5	
VA	LG&E - Westmoreland Altavista	Bituminous	2	
VA	Mirant Potomac River	Bituminous	5	
MI	Dan E. Karn	Bituminous; Subbituminous	2	
MI	Marysville Power Plant	Bituminous	4	
MD	H. A. Wagner	Bituminous	2	
PA	Armstrong	Bituminous	2	
WI	Genoa	Bituminous; Subbituminous	1	
IN	Cayuga (IN)	Bituminous	2	
IL	Wood River	Bituminous	2	
WI	Alma	Bituminous; Subbituminous	2	
PA	Montour	Bituminous	2	
MO	Meramec	Bituminous; Subbituminous	4	
IL	Vermilion	Bituminous	2	
IN	R. M. Schahfer	Subbituminous; Bituminous	4	
VA	Mecklenburg Cogeneration Facility	Bituminous	2	
NJ	Deepwater	Bituminous	1	
PA	Brunner Island	Bituminous	3	
NC	Cogentrix Dwayne Collier Battle Cogen	Bituminous	4	
NC	Dan River	Bituminous	3	
GA	Bowen	Bituminous	4	
MI	River Rouge Power Plant	Bituminous; Subbituminous	2	
WV	Albright	Bituminous	3	
IA	Dubuque	Bituminous	3	
SC	Williams	Bituminous	1	
VA	LG&E - Westmoreland Southampton	Bituminous	2	
IN	Gibson Generating Station	Bituminous	5	
MO	Southwest Power Station	Subbituminous	1	
NY	AES Cayuga (formerly NYSEG Milliken)	Bituminous	2	
MI	Erickson	Bituminous; Subbituminous	1	
TN	Kingston Fossil Plant	Bituminous	9	
CT	AES Thames	Bituminous	2	
PA	Sunbury	Bituminous; Coal refuse	6	
NJ	Hudson	Bituminous	1	
GA	Hammond	Bituminous	4	
MO	Sioux	Bituminous; Subbituminous	2	
MI	J. R. Whiting	Bituminous; Subbituminous	3	
AL	James H. Miller, Jr.	Subbituminous; Bituminous	4	
VA	SEI - Birchwood Power Facility	Bituminous	1	

State	Facility Name	Coal rank	No. units	Equipped with ACI
VA	Chesapeake Energy Center	Bituminous	4	
IL	E. D. Edwards	Bituminous	3	
NC	Riverbend	Bituminous	4	
FL	Stanton Energy Center	Bituminous	2	
IA	Lansing	Bituminous; Subbituminous	2	
CO	Comanche	Subbituminous	2	
NC	Buck	Bituminous	5	
KY	Big Sandy	Bituminous	2	
VA	Glen Lyn	Bituminous	3	
OH	Walter C. Beckjord	Bituminous	6	
CA	Mt. Poso Cogeneration	Bituminous; Subbituminous	1	
NC	Belews Creek	Bituminous	2	
CO	Hayden	Bituminous	2	
TX	Tolk	Subbituminous	2	
MD	R. Paul Smith	Bituminous	2	
CO	Valmont	Bituminous	1	
WV	Fort Martin	Bituminous	2	
MD	Mirant Dickerson	Bituminous	3	
NC	Marshall	Bituminous	4	
NY	Danskammer Generating Station	Bituminous	2	
VA	Chesterfield Power Station	Bituminous	4	
NJ	Logan Generating Plant	Bituminous	1	
NC	Mayo	Bituminous	2	
MI	James De Young	Bituminous	1	
FL	Indiantown Cogeneration Facility	Bituminous	1	
MA	Mount Tom	Bituminous	1	
NC	H. F. Lee	Bituminous	3	
OH	Hamilton	Bituminous	2	
PA	Homer City	Bituminous	3	
MS	R. D. Morrow, Sr. Generating Plant	Bituminous	2	
MD	Brandon Shores	Bituminous	2	
SC	H. B. Robinson	Bituminous	1	
MI	Eckert Station	Bituminous; Subbituminous	6	
MI	TES Filer City Station	Bituminous	1	
AZ	Coronado	Subbituminous	2	
TX	Harrington Station	Subbituminous; Bituminous	3	
OH	Cardinal	Bituminous	3	
VA	LG&E - Westmoreland Hopewell	Bituminous	2	
CO	Cherokee	Bituminous	4	
GA	Scherer	Bituminous; Subbituminous	4	
NC	Asheville	Bituminous	2	
WI	Nelson Dewey	Subbituminous	2	
OH	Killen Station	Bituminous	1	
FL	Deerhaven Generating Station	Bituminous	1	
KY	East Bend Station	Bituminous	1	
SC	Cope	Bituminous	1	
FL	Crystal River	Bituminous	4	

State	Facility Name	Coal rank	No. units	Equipped with ACI
MI	Harbor Beach Power Plant	Bituminous	1	
OH	J. M. Stuart	Bituminous	4	
IN	Tanners Creek	Bituminous; Subbituminous	4	
IN	Clifty Creek	Bituminous	6	
AL	Widows Creek Fossil Plant	Bituminous	8	
NC	L.V. Sutton	Bituminous	3	
WV	John E. Amos	Bituminous	3	
WV	Mitchell	Bituminous	2	
FL	St. Johns River Power Park	Bituminous	2	
NC	W. H. Weatherspoon	Bituminous	3	
MI	Presque Isle	Subbituminous	3	ACI
IA	Council Bluffs (a.k.a., Walter Scott, Jr.) Unit 4	Subbituminous	1	ACI
MT	Hardin Generator Project	Subbituminous	1	ACI
WI	Weston Unit 4	Subbituminous	1	ACI
NM	San Juan Units 3, 4	Subbituminous	2	ACI
CT	Bridgeport Harbor Station	Bituminous	1	ACI
MA	Brayton Point	Bituminous	3	ACI
NJ	Mercer	Bituminous	2	ACI
NJ	B. L. England	Bituminous	1	ACI
NV	TS Power Plant	Subbituminous	1	ACI
DE	Indian River	Bituminous	3	ACI
DE	Edge Moor	Bituminous	2	ACI

Attachment 6.

List of coal-fired electric utility steam generating units selected for non-dioxin/furan organic HAP testing

State	Facility Name	Unit number	On-line year
AR	Plum Point Energy	1	2009
CO	Comanche	3	2009
IL	Dallman	34	2009
LA	Rodemacher Power Station	3	2009
NV	TS Power Plant	1	2009
TX	J. K. Spruce	BLR2	2009
TX	Oak Grove	1	2009
TX	Oak Grove	2	2009
TX	Sandow Station	5	2009
WI	South Oak Creek	1	2009
WY	Two Elk Generating Station	1	2009
CO	Lamar	4	2008
KY	H. L. Spurlock	4	2008
PA	River Hill Power Company LLC	31	2008
SC	Cross	4	2008
WI	Weston	4	2008
WY	Wygen II	1	2008
IA	Council Bluffs	4	2007
AZ	Springerville	3	2006
SC	Cross	3	2006
WI	Manitowoc	9	2006
KY	H. L. Spurlock	3	2005
MT	Hardin Generator Project	1	2005
PA	Seward	1	2004
PA	Seward	2	2004
IL	Marion	123	2003
WY	Wygen I	3	2003
FL	Northside Generating Station	1	2002
FL	Northside Generating Station	2	2002
MS	Red Hills Generating Facility	AA001	2002
MS	Red Hills Generating Facility	AA002	2002
PR	AES Puerto Rico (Aurora)	1	2002
PR	AES Puerto Rico (Aurora)	2	2002
MO	Hawthorn	5A	2001
MD	AES Warrior Run Cogeneration Facility	BLR1	2000
MI	B. C. Cobb	5	2000
OH	Bay Shore	1	2000
SC	Cogen South	B001	1999
FL	Stanton Energy Center	2	1996
VA	Birchwood Power	1A	1996
VA	Clover Power Station	2	1996
FL	Indiantown Cogeneration Facility	AAB01	1995
MT	Yellowstone Energy LP	BLR1	1995
MT	Yellowstone Energy LP	BLR2	1995
NC	Westmoreland-LG&E Roanoke Valley II	BLR2	1995
PA	Colver Power Project	ABB01	1995
PA	Northhampton Generating LP	BLR1	1995

State	Facility Name	Unit number	On-line year
SC	Cope	COP1	1995
SC	Cross	1	1995
VA	Clover Power Station	1	1995
WY	Neil Simpson II	2	1995
FL	Cedar Bay Generating LP	CBA	1994
FL	Cedar Bay Generating LP	CBB	1994
FL	Cedar Bay Generating LP	CBC	1994
NJ	Chambers Cogeneration LP	BOIL1	1994
NJ	Chambers Cogeneration LP	BOIL2	1994
NJ	Logan Generating Plant	B01	1994
NC	Westmoreland-LG&E Roanoke Valley I	BLR1	1994
PA	Scrubgrass Generating	UNIT 1	1993
PA	Scrubgrass Generating	UNIT 2	1993
UT	Sunnyside Cogen Associates	1	1993
HI	AES Hawaii	A	1992
HI	AES Hawaii	B	1992
LA	R. S. Nelson	2A	1992
LA	R. S. Nelson	1A	1992
PA	Panther Creek Energy Facility	BLR1	1992
PA	Panther Creek Energy Facility	BLR2	1992
PA	Piney Creek Project	BRBR1	1992
TX	J. K. Spruce	BLR1	1992
VA	Altavista Power Station	1	1992
VA	Cogentrix of Richmond	1A	1992
VA	Cogentrix of Richmond	1B	1992
VA	Cogentrix of Richmond	2A	1992
VA	Cogentrix of Richmond	2B	1992
VA	Cogentrix of Richmond	3A	1992
VA	Cogentrix of Richmond	3B	1992
VA	Cogentrix of Richmond	4A	1992
VA	Cogentrix of Richmond	4B	1992
VA	Mecklenburg Cogeneration Facility	BLR1	1992
VA	Mecklenburg Cogeneration Facility	BLR2	1992
VA	Southampton Power Station	1	1992
WV	Grant Town Power Plant	BLR1A	1992
WV	Grant Town Power Plant	BLR1B	1992
WV	North Branch	1A	1992
WV	North Branch	1B	1992
AL	James H. Miller, Jr.	4	1991
CO	Nucla	1	1991
MD	Brandon Shores	2	1991
OH	W. H. Zimmer Generating Station	1	1991
OK	AES Shady Point	1A	1991
OK	AES Shady Point	1B	1991
OK	AES Shady Point	2A	1991
OK	AES Shady Point	2B	1991
PA	Cambria Cogen	B1	1991
PA	Cambria Cogen	B2	1991
TX	Twin Oaks Power Station (formerly TNP-One)	U2	1991
WV	Morgantown Energy Facility	CFB1	1991
WV	Morgantown Energy Facility	CFB2	1991
AZ	Springerville	2	1990

State	Facility Name	Unit number	On-line year
CA	ACE Cogeneration Facility	CFB	1990
CT	AES Thames	A	1990
CT	AES Thames	B	1990
KY	Shawnee Fossil Plant	10	1990
KY	Trimble County	1	1990
ME	Rumford Cogeneration	6	1990
ME	Rumford Cogeneration	7	1990
MI	TES Filer City Station	1	1990
MI	TES Filer City Station	2	1990
MT	Colstrip Energy LP	BLR1	1990
NC	Cogentrix Dwayne Collier Battle Cogen	1A	1990
NC	Cogentrix Dwayne Collier Battle Cogen	1B	1990
NC	Cogentrix Dwayne Collier Battle Cogen	2A	1990
NC	Cogentrix Dwayne Collier Battle Cogen	2B	1990
PA	Ebensburg Power	031	1990
PA	Foster Wheeler Mt. Carmel Cogen	SG-101	1990
PA	St. Nicholas Cogeneration Project	1	1990
TX	Twin Oaks Power Station (formerly TNP-One)	U1	1990
AL	James H. Miller, Jr.	3	1989
CA	Mt. Poso Cogeneration	BL01	1989
CA	Rio Bravo Jasmin	CFB	1989
CA	Rio Bravo Poso	CFB	1989
GA	Scherer	4	1989
IN	Rockport	MB2	1989
PA	Kline Township Cogen Facility	1	1989
PA	P. H. Glatfelter	5PB036	1989
CA	Stockton Cogen	BLR1	1988
FL	Central Power and Lime, Inc.	1	1988
FL	St. Johns River Power Park	2	1988
PA	John B. Rich Memorial Power Station	CFB1	1988
PA	John B. Rich Memorial Power Station	CFB2	1988
PA	Wheelabrator Frackville Energy	BLR1	1988
TX	Fayette Power Project	3	1988
FL	St. Johns River Power Park	1	1987
FL	Stanton Energy Center	1	1987
GA	Scherer	3	1987
MN	Sherburne County Generating Plant	3	1987
NY	Danskammer Generating Station	3	1987
NY	Danskammer Generating Station	4	1987
PA	AES Beaver Valley Partners Beaver Valley	2	1987
PA	AES Beaver Valley Partners Beaver Valley	3	1987
PA	AES Beaver Valley Partners Beaver Valley	4	1987
PA	WPS Westwood Generation LLC	031	1987
SC	Stone Container Florence Mill	PB4	1987
UT	Intermountain Power Project	2SGA	1987
IN	A. B. Brown	2	1986
IN	Petersburg	4	1986
IN	R. M. Schahfer	18	1986
KY	D. B. Wilson	W1	1986
LA	Dolet Hills Power Station	1	1986
MT	Colstrip	4	1986
ND	Antelope Valley	B2	1986

State	Facility Name	Unit number	On-line year
OK	GRDA	2	1986
PA	Chester Operations	10	1986
TX	AES Deepwater	AAB001	1986
TX	Limestone	LIM2	1986
TX	Oklaunion	1	1986
UT	Bonanza	1-1	1986
UT	Intermountain Power Project	1SGA	1986
AL	James H. Miller, Jr.	2	1985
AL	Mobile Energy Services LLC	7PB	1985
AZ	Springerville	1	1985
AR	Independence	2	1985
FL	Big Bend	BB04	1985
MI	Belle River Power Plant	2	1985
NV	North Valmy Generating Station	2	1985
TX	Limestone	LIM1	1985
TX	H. W. Pirkey	1	1985
TX	Tolk	172B	1985
WI	Edgewater	5	1985
WI	Pleasant Prairie	2	1985
CO	Craig	C3	1984
CO	Rawhide	101	1984
FL	Crystal River	5	1984
FL	Seminole	1	1984
FL	Seminole	2	1984
GA	Scherer	2	1984
IN	Rockport	MB1	1984
KY	Ghent	4	1984
LA	Big Cajun 2	2B3	1984
MD	Brandon Shores	1	1984
MI	Belle River Power Plant	1	1984
MT	Colstrip	3	1984
NM	Escalante	1	1984
NY	AES Somerset LLC	1	1984
ND	Antelope Valley	B1	1984
OK	Muskogee	6	1984
SC	Cross	2	1984
AR	Independence	1	1983
IN	Merom	1SG1	1983
IN	R. M. Schahfer	17	1983
IA	Louisa	101	1983
IA	Muscatine Plant #1	9	1983
KS	Holcomb	SGU1	1983
KS	Jeffrey Energy Center	3	1983
MI	J. B. Sims	3	1983
MI	Shiras	3	1983
NV	Reid Gardner	4	1983
NC	Mayo	1A	1983
NC	Mayo	1B	1983
TX	Gibbons Creek	1	1983
UT	Hunter	3	1983
FL	C. D. McIntosh, Jr.	3	1982
FL	Crystal River	4	1982

State	Facility Name	Unit number	On-line year
GA	Scherer	1	1982
IL	Newton	2	1982
IN	Gibson Generating Station	5	1982
IN	Merom	2SG1	1982
IA	Ames Electric Services Power Plant	8	1982
KY	Mill Creek	4	1982
LA	R. S. Nelson	6	1982
LA	Rodemacher Power Station	2	1982
MI	Endicott Station	1	1982
MO	Thomas Hill	MB3	1982
NE	Gerald Gentleman Station	2	1982
NE	Platte	1	1982
NM	San Juan	4	1982
ND	Stanton Station	10	1982
OH	Killen Station	2	1982
OK	GRDA	1	1982
OK	Hugo	1	1982
TX	San Miguel	SM-1	1982
TX	Tolk	171B	1982
TX	W. A. Parish	WAP8	1982
TX	Welsh	3	1982
WY	Laramie River Station	3	1982
AZ	Cholla	4	1981
AR	White Bluff	2	1981
CO	Pawnee	1	1981
FL	Deerhaven Generating Station	B2	1981
IA	Ottumwa	1	1981
KS	Nearman Creek	N1	1981
KY	East Bend Station	2	1981
KY	Ghent	3	1981
KY	H. L. Spurlock	2	1981
KY	R. D. Green	G2	1981
LA	Big Cajun 2	2B2	1981
MS	Victor J. Daniel, Jr.	2	1981
MO	Sikeston Power Station	1	1981
NE	Whelan Energy Center	1	1981
NV	North Valmy Generating Station	1	1981
ND	Coal Creek	2	1981
ND	Coyote	B1	1981
SC	Winyah	4	1981
TX	Sandow Station	4	1981
WI	Weston	3	1981
WY	Laramie River Station	2	1981
AL	Charles R. Lowman	3	1980
AZ	Cholla	3	1980
AZ	Coronado	U2B	1980
AR	White Bluff	1	1980
CO	Craig	C1	1980
CO	Ray D. Nixon	1	1980
DE	Indian River	4	1980
KS	Jeffrey Energy Center	2	1980
LA	Big Cajun 2	2B1	1980

Attachment 8.

List of oil-fired electric utility steam generating units

State	Facility Name	No. Units
CT	Bridgeport Harbor Station	1
CT	Devon	2
CT	Middletown	3
CT	Montville	2
CT	New Haven Harbor	1
CT	Norwalk Harbor Station	2
DC	Benning	2
DE	Edge Moor	1
DE	McKee Run	3
FL	Anclote	2
FL	C. D. McIntosh, Jr.	2
FL	Cape Canaveral	2
FL	Indian River	3
FL	Manatee	2
FL	Martin	2
FL	Northside Generating Station	1
FL	P. L. Bartow	3
FL	Port Everglades	4
FL	Riviera	2
FL	Sanford	1
FL	Suwannee River	3
FL	Turkey Point	2
GA	McManus	2
GU	Cabras	2
GU	Tanguisson Power Plant	1
HI	Honolulu	2
HI	Kahe	6
HI	Waiau	6
IL	Havana	8
IL	Meredosia	1
IN	Edwardsport	1
IN	Harding Street Station (a.k.a., E. W. Stout Generating Station)	2

STANDARD FORM 83-I SUPPORTING STATEMENT FOR OMB REVIEW OF EPA ICR No. 2362.01:

INFORMATION COLLECTION REQUEST FOR NATIONAL EMMISION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP) FOR COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Sector Policies and Programs Division
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

June 17, 2009

Attachment 2.

Industry Burden and Costs for Responding to the Questionnaire

Activity	(A) Hours per Occurrence	(B) Occurrences/ Respondent/Year	(C) Hours/ Respondent/ Year (A x B)	(D) Respondents/ Year	(E) Technical Hours/Year (C x D)	(F) Managerial Hours/Year (E x 0.05)*	(G) Clerical Hours/Year (E x 0.10)	(F) Cost/ Year
1. APPLICATIONS (Not Applicable)								
2. SURVEY AND STUDIES (Not Applicable)								
3. ACQUISITION, INSTALLATION, AND UTILIZATION OF TECHNOLOGY AND SYSTEMS (Not Applicable)								
4. REPORT REQUIREMENTS								
A. Read Instructions								
Facility	2	1	2	555	1,110.0	55.5	111.0	$120,048
B. Required Activities								
Gather existing reports with requested data	8	1	8	1325	10,600.0	530.0	1,060.0	$1,145,401
Extract requested data from reports	8	1	8	1325	10,600.0	530.0	1,060.0	$1,145,401
Enter extracted data into Web Site	16	1	16	1325	21,200.0	1,060.0	2,120.0	$2,290,802
QA/QC entered data on Web Site	8	1	8	1325	10,600.0	530.0	1,060.0	$1,145,401
Read Test Plan provided by EPA for stack testing	0.7	1	0.7	471	329.7	16.5	33.0	$35,657
Procure contractor to perform testing	20	1	20	471	9,420.0	471.0	942.0	$1,018,783
Submit stack test results through the EKT	2	1	2	471	942.0	47.1	94.2	$101,878
QA/QC entered data on Web Site	1	1	1	471	471.0	23.6	47.1	$50,939
HCl and HF testing from coal-fired utility units (w/ and w/o FGD)* *		217						$8,246,000
Dioxin/furan emissions from coal-fired utility units**		149						$7,450,000
Non-Dioxin/furan emissions (CO, VOC, and THC) from coal-fired utility units**		184						$19,688,000
Hg and non-Hg Metallic HAPs from coal-fired utility units**		214						$24,824,000
All HAP surrogates from oil-fired utility units**		116						$35,087,000
Plant personnel for testing***	16	3	48	471	22,608.0	226.1	-	$2,232,199
Review the Test Report Data	5	1	5	471	2,355.0	117.8	-	$275,954
C. Create Information (Included in 4B)								
D. Gather Existing Information (Included in 4C)								
E. Write Report (Not Applicable)								
5. RECORDKEEPING REQUIREMENTS (Not applicable)								
TOTAL ANNUAL LABOR BURDEN AND COST					90,236	3,607	6,527	$104,807,458
						100,370	Hours	
ANNUAL CAPITAL COSTS (Not Applicable)								$ -
ANNUALIZED CAPITAL COSTS (Not Applicable)								$ -
TOTAL ANNUAL COSTS (O&M) (Not Applicable)								$ -
TOTAL ANNUALIZED COSTS (Annualized capital + O&M costs) (Not Applicable)								$ -

*We assumed no clerical hours and less managerial hours were needed when plant personnel were working with Contractors to conduct testing

**This is the assumed testing costs for facilities when testing is performed by a Contractor

***This assumes 3 facility technical staff over 2 days for working with the Contractor to conduct testing. All administrative work is assumed to be included in the contractor testing and no facility administrative staff is required for testing.

Attachment 3.

Agency Burden and Costs

Activity	(A) EPA Hours/ Occurrence	(B) Occurrences/ Plant/Year	(C) EPA Hours/ Plant/Year (A x B)	(D) Plants/ Year	(E) EPA Technical Hours/ Year (C x D)	(F) EPA Managerial Hours/Year	(G) EPA Clerical Hours/Year	(H) Cost, $
Develop questionnaire	80	1	80	1	80.0	4.0	8.0	$ 4,838
Develop web site for data entry from facilities	120	1	120	1	120.0	6.0	12.0	$ 7,257
Mail out Questionnaire	4	1	4	555	2,220.0	111.0	222.0	$ 134,250
Answer respondent questions	0.25	1	0.25	55.5	13.9	0.7	1.4	$ 839
Analysis request for confidentiality	0.25	1	0.25	132.5	33.1	1.7	3.3	$ 2,003
Review and Analyze responses	4	1	4	1325	5,300.0	265.0	530.0	$ 320,506
Review the electronically submitted stack testing data	5	1	5	880	4,400.0	220.0	440.0	$ 266,080
Total Annual Hours					12,167	608.35	1,217	$ 735,773
						13,992	hours	
Expenses								
Printing Questionnaire	$ 694							
Postage to mail Questionnaire Registered Mail/Receipt	$ 6,771							
Computer Storage of data and web interface	$ 1,200							
Total Expenses								$ 8,665
								$ 744,437

We assume that EPA will mail one questionnaire to each facility.
Assumes that 10% of the facilities will have questions
Assumes that 10% of the units will have confidential data

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:

FP&L Cape Canaveral Plant
6000 North U.S. Highway 1
Cocoa, FL 32927

PERMIT NUMBER: FL0001473 (Major)
PA FILE NUMBER: FL0001473-008-IW1S
ISSUANCE DATE: August 10, 2005
EXPIRATION DATE: August 9, 2010

RESPONSIBLE AUTHORITY:

Mr. Lowell Trotter
Plant General Manager

FACILITY:

FP&L Cape Canaveral Plant
6000 North U.S. Highway 1
Cocoa, FL 32927
Brevard County

Latitude: 28° 28' 10" N Longitude: 80° 45' 54" 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 (NPDES). The above named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

The plant consists of two steam electric generating units. Units 1 and 2 have a nominal generating capacity of 400 megawatts.

The plant uses a once-through condenser cooling water system. Condenser cooling water is drawn from the Indian River through an intake canal located on the southern end of the plant. The cooling water passes through the plant condensers and then discharged back to the Indian River via two 78-inch underground pipes that empty into their respective outfall structures. The discharge structures for the two units are located approximately 550 feet apart. Auxiliary equipment cooling water from both units is discharged to the Indian River through a single 18-inch outfall pipe located approximately midway between the once-through cooling outfall structures.

The main condenser Once-Through Cooling Water (OTCW) is chlorinated at the intake for both units. The facility dechlorinates the once-through cooling water using sodium bisulfite prior to discharge. Auxiliary Equipment Cooling Water (AECW) may also be chlorinated using continuous low level chlorination. Boiler blowdown is captured and reused. Wastewater from the on-site water treatment system is discharged via existing Outfall D-030 to the Indian River until 6 months beyond the issuance date of this permit. After such time, wastewater from the on-site

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 15
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-10) (Previously RRL-6)
DATE 11/02/09

PERMITTEE:

FP&L Cape Canaveral Plant
6000 North U.S. Highway 1
Cocoa, FL 32927

PERMIT NUMBER: FL0001473

Issuance date: August 10, 2005
Expiration date: August 9, 2010

water treatment system will be discharged internally to the AECW outfall or, alternatively, to the OTCW outfalls.

WASTEWATER TREATMENT:
Wastewater generated during metal cleaning operations is discharge to the two lined Solids Settling Basins (B-1A and B-1B). Reverse osmosis reject from boiler blowdown source water and boiler chemical cleaning rinses (in which EDTA, Citro-Solv or equivalent cleaner is used in the cleaning operation) may also be routed to the solids settling basins. The wastewater in the basins is treated by adding caustic that allows for the precipitation of metals followed by sedimentation. Treated effluent from the solids settling basins is routed to the Evaporation/Percolation Basin (EP-1) and acid is added for pH adjustment. Treated wastewater from the evaporation/percolation basin is used for spray irrigation on the berms of the fuel oil containment area. This area is designated as E/P Basin Spray Area (SP-1).

Stormwater runoff and drainage from equipment areas and fuel oil handling facilities as well as equipment rinse water in the power block areas are collected via floor drains. The collected runoff is then routed through oil removal devices prior to discharge to the equipment area runoff treatment and disposal system consisting of the Forwarding Sump (S-3), Equipment Area Runoff Basin (B-3), organo-clay polishing filters, and the Runoff Disposal Area (DA-1). Under light rainfall conditions, runoff from the forwarding sump is routed through the organo-clay filters directly to the Disposal Area DA-1. Under medium and chronic rainfall conditions (up to one inch of rainfall), the runoff from the forwarding sump is routed to the Runoff Basin B-3 and then pumped through the organo-clay filters to the runoff Disposal Area DA-1. On rare occasions and under chronic heavy rainfall conditions (in excess of one inch rainfall), the runoff that is not routed to the runoff basin or pumped through the organo-clay filters to the runoff disposal area, overflows at the forwarding sump and discharged to the Indian River via Outfall D-016.

EFFLUENT DISPOSAL:

Surface Water Discharge:

An existing discharge of 332 MGD annual average flow and 396 MGD maximum daily flow to Indian River (Class III Marine waters), D-011. The once-through cooling water from Unit 1 is located approximately at latitude 28° 28' 11" N, longitude 80° 45' 46" W.

An existing discharge of 332 MGD annual average flow and 396 MGD maximum daily flow to Indian River (Class III Marine waters), D-012. The once-through cooling water outfall from Unit 2 is located approximately at latitude 28° 28' 14" N, longitude 80° 45' 50" W.

An existing discharge of 13.8 MGD annual average flow and 30.0 MGD maximum daily flow to the Indian River (Class III Marine waters), D-015. The auxiliary equipment cooling water outfall for Units 1 & 2 line is located approximately at latitude 28° 28' 12" N, longitude 80° 45' 48" W.

An existing discharge to Indian River (Class III Marine waters), D-016. The equipment area runoff basin overflow outfall is located approximately at latitude 28° 28' 18" N, longitude 80° 45' 51" W.

An existing discharge to Indian river (Class III Marine waters), D-028. The stormwater from fuel oil storage tank secondary containment area outfall is located approximately at latitude 28° 28' 18" N, longitude 80° 45' 51" W.

An existing discharge to Indian River (Class III Marine waters), D-029. The non-equipment area stormwater outfall is located approximately at latitude 28° 28' 12" N, longitude 80° 45' 48" W.

PERMITTEE:	PERMIT NUMBER:	FL0001473
FP&L Cape Canaveral Plant 6000 North U.S. Highway 1 Cocoa, FL 32927	Issuance date: Expiration date:	August 10, 2005 August 9, 2010

An existing discharge to Indian River (Class III Marine waters), D-030. The water treatment system wastewater outfall is located approximately at latitude 28° 28' 18" N, longitude 80° 45' 51" W.

Land Application:

An existing land application system (G-010) consisting of Evaporation/Percolation Basin (EP-1) and E/P Basin Spray Area (SP-1). The Evaporation/Percolation Basin (EP-1) is located approximately at latitude 28° 28' 14" N, longitude 80° 45' 51" W. The E/P Basin Spray Area (SP-1) is located approximately at latitude 28° 28' 16" N, longitude 80° 45' 53" W.

An existing land application system (G-020) consisting of Equipment Area Runoff Basin (B-3) and Runoff Disposal Area (DA-1). The Equipment Area Runoff Basin (B-3) is located approximately at latitude 28° 28' 10" N, longitude 80° 45' 54" W. The Runoff Disposal Area (DA-1) is located approximately at latitude 28° 28' 08" N, longitude 80° 45' 55" W.

Internal Outfalls:

This permit authorizes discharge of 0.05 MGD annual average flow from internal Outfall I-017 to the ABCW Outfall (D-015) or, alternatively, to the OTCW Outfalls (D-011 and D-012).

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions as set forth in Part I through Part VIII on pages 4 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 Once-Through Cooling Water (OTCW) from Outfalls D-011 and D-012. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations				Monitoring Requirements		
Parameters (units)	Monthly Average	Instantaneous Maximum	Maximum Daily Average	Instantaneous Minimum	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	--	Continuous	Calculated	FLW-1, FLW-2
Chlorination (HOURS/UNIT/DAY)	--	2.0	--	--	Daily	Calculated	OTH-1, OTH-2
Oxidants, Total Residual (MG/L)	--	--	0.01	--	Weekly	Grab[1]	EFF-1, EFF-2
Temperature (F), Water (DEG.F)	Report[2]	Report[2]	--	--	6/Day	Instantaneous	EFF-1, EFF-2
Dissolved Oxygen (MG/L)	--	--	--	Report	Monthly[3]	Grab	INT-1 and EFF-1 or INT-2 and EFF-2

2. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
FLW-1, FLW-2	Once-through cooling water intake for Units 1 and 2, respectively, flow monitoring location.
EFF-1, EFF-2	Once-through cooling water discharge structures for Units 1 and 2, respectively.
INT-1, INT-2	Once-through or auxiliary equipment cooling water for Units 1 and 2, respectively.
OTH-1, OTH-2	At the point of chlorine addition for Units 1 and 2, OTCW

[1] Grab samples shall consist of multiple samples collected at approximately the beginning, middle, and end of the chlorination period.
[2] Discharge from Outfall D-001 is subject to thermal limitations established by Rule 62-302.520(1), F.A.C.
[3] Grab samples for both the intake and discharge shall be taken concurrently every 4 hours, for 24 hours, once month. Intake and discharge sampling during a monthly sampling event is only required from one power plant unit, i.e. Unit 1 or Unit 2. The permittee may request a reduction or discontinuance of these monitoring requirements after 12 months of monitoring.

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3. 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 Units 1 and 2 used in lieu of OTCW** from Outfall D-013 (formerly D-0D1) and Outfall D-014 (formerly D-0D2). Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	Monthly Average	Maximum Daily Average	Instantaneous Maximum	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	Continuous	Calculated	FLW-3 FLW-4
Temp. Diff. between Intake and Discharge (DEG.F)	--	--	20.0	6/Day	Calculated	INT-1 INT-2 EFF-1 EFF-2
Oxidants, Total Residual (MG/L)	--	0.01		Weekly	Grab[4]	EFF-1 EFF-2
Chlorination (HOURS/UNIT/DAY)	--	24	--	Daily	Calculated	OTH-3

4. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
FLW-3, FLW-4	Auxiliary equipment cooling water intake for Units 1 and 2, respectively, flow monitoring location.
INT-1, INT-2	Once-through or auxiliary equipment cooling water intake for Units 1 and 2, respectively.
EFF-1, EFF-2	Once-through cooling water discharge structures for Units 1 and 2, respectively.
OTH-3	At the point of chlorine addition for Units 1 and 2 AECW

[4] Multiple grabs shall be collected during daylight hours every 4 hours during TRO discharge.

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5. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge Units 1 and 2 Auxiliary Equipment Cooling Water from Outfall D-015 (formerly D-081). Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	Monthly Average	Maximum Daily Average	Instantaneous Maximum	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	Continuous	Calculated	FLW-3 FLW-4
Oxidants, Total Residual (MG/L)	--	0.01	--	Weekly	Grab[5]	EFF-3
Chlorination (HOURS/UNIT/DAY)	--	24	--	Daily	Calculated	OTH-3

6. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
FLW-3, FLW-4	Flow monitoring location for auxiliary equipment cooling water for Units 1 and 2, respectively.
OTH-3	At the point of chlorine addition for Units 1 and 2 ABCW
EFF-3	Combined auxiliary equipment water cooling discharge from Units 1 and 2 prior to actual discharge to the receiving waters or mixing with other waste streams

[5] Multiple grabs shall be collected during daylight hours every 4 hours during TRO discharge.

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7. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to **Equipment Area Runoff Basin Overflow** from Outfall D-016 (formerly D-0B0). Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	Monthly Average	Maximum Daily Average	Instantaneous (Min/Max)	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	Per Discharge[6]	Calculated	EFF-4
Oil & Grease (MG/L)	Report	5.0	--	Per Discharge[6]	Grab	EFF-4
Solids, Total Suspended (MG/L)	30.0	100.0	--	Per Discharge[6]	Grab	EFF-4
pH Range (SU)	--	--	6.0 to 9.0	Per Discharge[6]	Grab	EFF-4

8. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
EFF-4	Discharge from the forwarding sump prior to actual discharge to receiving waters or mixing with other waste stream.

9. During the period beginning on the issuance date and lasting until 6 months beyond the issuance date, the permittee is authorized to discharge **Water Treatment Plant Wastewater** from existing Outfall D-030 to the Indian River. Such discharge shall be limited and monitored by the permittee as specified below:

Parameters (units)	Monthly Average	Maximum Daily Average	Instantaneous	Annual Average	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	--	2/Month	Calculated	EFF-5
Solids, Total Suspended (MG/L)	30.0	100.0	--	--	2/Month	Composite[7]	EFF-5
Oil and Grease (MG/L)	--	5.0	--	--	2/Month	Grab	EFF-5
pH Range (S.U.)	--	--	6.0 to 9.0	--	2/Month	Grab	EFF-5

[6] Monitoring of discharge from the Oil separator/Forwarding Sump is not required provided the first one inch rainfall is retained by the Stormwater Basin and associated spray field. Subsequent overflow may be discharged without monitoring requirements, except that there shall be no discharge of a visible oil sheen. In the event that these conditions are not met, monitoring shall be 1/discharge.

[7] Shall be defined as a composite of grab samples taken at the beginning, middle and end of the Backwash Basin discharge period.

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10. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
EFF-5	At the point of discharge to the receiving waters.

11. During the period beginning at initiation of discharge and lasting through the expiration date of this permit, the permittee is authorized to discharge Water Treatment Plant Wastewater from Outfall I-017 to the AECW Outfall (D-015) or to the OTCW Outfalls (D-011 and D-012). Such discharge shall be limited and monitored by the permittee as specified below:

Parameters (units)	Monthly Average	Maximum Daily Average	Instantaneous	Annual Average	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	--	2/Month	Calculated	OUI-1
Solids, Total Suspended (MG/L)	30.0	100.0	--	--	2/Month	Grab	OUI-1
Oil and Grease (MG/L)	15.0	20.0	--	--	2/Month	Grab	OUI-1
pH Range (S.U.)	--	--	6.0 to 9.0	--	2/Month	Grab	OUI-1
Nitrogen, Total as N (LBS/DAY)	--	--	--	7.0	Monthly	Grab	OUI-1
Phosphorus, Total as P, (LBS/DAY)	--	--	--	0.4	Monthly	Grab	OUI-1

12. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
OUI-1	At the point of discharge to the AECW or OTCW conduits.

13. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge from Outfall D-028 (formerly D-0B), 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.

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.

14. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge Outfall D-029 (formerly D-0S0), non-equipment area stormwater. Discharge of non-equipment area stormwater is permitted without limitation or monitoring requirements.

15. OTCW and ABCW limitations and monitoring requirements for TRO are not applicable for any week in which chlorine is not added to Units 1 or 2.

16. Intake Screen wash water may be discharged without limitation or monitoring requirements, except that there shall be no discharge of a visible sheen.

17. There shall be no discharge of floating solids or visible foam in other than trace amounts.

18. The discharge shall not cause a visible sheen on the receiving water.

B. Underground Injection Control Systems

1. This section is not applicable to this facility.

C. Land Application Systems

1. The discharge from land application systems G-010 and G-020 is authorized without limitations or monitoring requirements.

D. Other Methods of Disposal or Recycling

1. There shall be no discharge of industrial wastewater from this facility to ground or surface waters, except as authorized by this permit.

E. 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 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 quantification limits), which is titled "Florida Department of Environmental Protection Table as Required By Rule 62-4.246(4) Testing Methods for Discharges to Surface Water" dated June 21, 1996, is available from the Department on request. 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;

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b. The laboratory reported PQL 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 a PQL, which is equal to or less than the applicable water quality criteria stated in 62-302 FAC; and

c. If the PQLs 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 PQL shall be used.

Where the analytical results are below method detection or practical quantification 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. 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. However, where necessary, the permittee may request approval for alternative methods or for alternative MDLs and PQLs for any approved analytical method, in accordance with the criteria of Rules 62-160.520 and 62-160.530, F.A.C.

2. Parameters which must be monitored as a result of a surface water discharge shall be analyzed using a sufficiently sensitive method in accordance with 40 CFR Part 136.

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, at the address listed below, the 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	DMR 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 31	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 shall make copies of the attached DMR form(s) and shall submit the completed DMR form(s) to the Department at the address specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

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4. Unless specified otherwise in this permit, all reports and notifications required by this permit, including twenty-four hour notifications, shall be submitted to or reported to the Central District Office at the address specified below:

   Central District Office
   3319 Maguire Boulevard Suite 232
   Orlando, Florida 32803-3767

   Phone Number - (407) 894-7555
   FAX Number - (407) 897-2966
   All FAX copies shall be followed by original copies.

5. All reports and other information shall be signed in accordance with requirements of Rule 62-620.305, F.A.C.

6. The permittee shall provide safe access points for obtaining representative samples which are required by this permit.

7. If there is no discharge from the facility on a day scheduled for sampling, the sample shall be collected on the day of the next discharge.

8. Bypasses subject to General Conditions VIII.20. and VIII.22. shall be monitored or estimated daily, or as approved by the Department for flow and other parameters required for the specific outfall which is bypassed. Monitoring results shall be reported to the Department.

9. The Permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on December 21, 2000.

10. 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 address monitoring of aquatic species as necessary, and shall include reporting requirements. 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.

II. Industrial Sludge Management Requirements

A. Basic Management Requirements

1. Disposal of sludge in a solid waste management facility permitted by the Department shall be in accordance with the requirements of Chapter 62-701, F.A.C. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in compliance with requirements of Chapter 62-730, F.A.C.

2. The permittee shall keep records of the amount of sludge or residuals disposed, transported, or incinerated. 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.

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III. Ground Water Monitoring Requirements

1. During the period of operation authorized by this permit, the permittee shall continue to sample ground water at the existing monitoring wells identified in Permit Condition III. 2. below, in accordance with this permit and the approved ground water monitoring plan prepared in accordance with Rule 62-522.600, F.A.C. Within 90 days of placing the new or modified wastewater facility into operation, or installation of new monitoring wells, whichever occurs sooner, the permittee shall begin sampling ground water at the new monitoring wells identified in Permit Condition III. 2 below in accordance with this permit and the approved ground water monitoring plan.

2. The following monitoring wells shall be sampled quarterly. Sampling must be reasonably spaced to be representative of potentially changing conditions:

All Sites							
CA-MW-1	MWB-2683	3005A15832	2683	21	Surficial	Background	Existing
Equipment Area Runoff Basin (B-3)							
CA-MW-2	MWC-2682	3005A15833	2682	21	Surficial	Compliance	Existing
E/P Basin Spray Area (SP-1)							
OB-2	MWC-2686	3005A11264	2686	25.6	Surficial	Compliance	Existing
Solids Settling Basins (B-1A and B-1B)							
OB-3	MWC-2685	3005A11265	2685	24.9	Surficial	Compliance	Existing
Evaporation/Percolation Basin (EP-1)							
OB-5	MWC-26897	--	26897	18	Surficial	Compliance	Existing

MWB = Background; MWC = Compliance

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3. The following parameters shall be analyzed quarterly in each of the monitoring wells identified in Item III. 2. except Monitoring Well OB-5:

Parameter Name	Standard Compliance Well Limit	Units
Chloride	Report[8]	mg/L
pH	Report[8]	SU
Sodium	Report[9]	mg/L
Specific Conductance	Report	Umhos
Sulfate	Report[8]	mg/L
Total Dissolved Solids (TDS)	Report[8]	mg/L
Total Recoverable Petroleum Hydrocarbons	5.0	mg/L
Turbidity	Report	NTU
Vinyl Chloride	1	ug/L
Water Level Relative to NGVD	Report	Feet, NGVD

[8] This facility has been in operation since 1977 and is an existing installation as defined in F.A.C. Rule 62-522.200(1) and is exempt from compliance with secondary standards for ground water at the edge of the zone of discharge in accordance with *F.A.C. Rules 62-520.520* and *62-522.300(6)*.
[9] The permittee is exempted from compliance with the Class G-II ground water standard for sodium in accordance with the Final Order Of Agency Action (sodium exemption) signed by the Secretary on October 12, 2004. This sodium exemption is effective for the duration of this permit.

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4. The following parameters shall be analyzed quarterly in Monitoring Well OB-5 identified in Item III: 2:

Parameter Name	Standard Compliance Well Limit	Units
Aluminum	Report[10]	ug/L
Antimony (added 2/04)	6	ug/L
Beryllium (added 2/04)	4	ug/L
Cadmium	5	ug/L
Chloride	Report[10]	mg/L
Chromium	100	ug/L
Copper	Report[10]	ug/L
Cyanide	200	ug/L
Fluoride	4,000	ug/L
Iron	Report[10]	ug/L
Manganese	Report[10]	ug/L
Mercury	2.0	ug/L
Nickel	100	ug/L
pH	Report[10]	SU
Silver	Report[10]	ug/L
Sodium	Report[11]	mg/L
Specific Conductance	Report	mmhos
Sulfate	Report[10]	mg/L
TDS	Report[10]	mg/L
Tetrachloroethylene	3	ug/L
Total Phenols	Report	ug/L
Trichloroethylene	3	ug/L
Total Recoverable Petroleum Hydrocarbons	5.0	mg/L
Turbidity	Report	NTU
Vinyl chloride	1	ug/L
Zinc	Report[10]	ug/L
Water Level (ft NGVD)	Report	Feet, NGVD

5. The zone of discharge extends to the facility property boundary, and vertically to the base of the shallow water table aquifer.

6. The permittee's discharge to ground water shall not cause a violation of water quality standards for ground waters at the boundary of the zone of discharge in accordance with Rules 62-520.400 and 62-520.420, F.A.C.

7. The permittee's discharge to ground water shall not cause a violation of the minimum criteria for ground water specified in Rule 62-520.400, F.A.C., within the zone of discharge.

[10] This facility has been in operation since 1977 and is an existing installation as defined in F.A.C. Rule 62-522.200(1) and is exempt from compliance with secondary standards for ground water at the edge of the zone of discharge in accordance with F.A.C. Rules 62-520.520 and 62-522.300(6).
[11] The permittee is exempted from compliance with the Class G-II ground water standard for sodium in accordance with the Final Order Of Agency Action (sodium exemption) signed by the Secretary on October 12, 2004. This sodium exemption is effective for the duration of this permit.

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8. If the concentration for any constituent listed in Permit Condition III.3 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 natural background quality shall be the prevailing standard.

9. Water levels shall be recorded prior to evacuating the well for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NGVD allowable) at a precision of plus or minus 0.1 feet.

10. Ground water monitoring wells shall be purged prior to sampling to obtain a representative sample.

11. Analyses shall be conducted on un-filtered samples, unless filtered samples have been approved by the Department as being more representative of ground water conditions.

12. If a monitoring well becomes damaged or cannot be sampled for some reason, the permittee shall notify the Department immediately and a written report shall follow within seven days detailing the circumstances and remedial measures taken or proposed. Repair or replacement of monitoring wells shall be approved in advance by the Department.

13. The permittee shall provide verbal notice to the Department as soon as practical after discovery of a sinkhole within an area for the management or application of wastewater or sludge. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department in a written report within 7 days of the sinkhole discovery.

14. Ground water monitoring test results shall be submitted on Part D of DEP Form 62-620.910(10) (attached) and shall be submitted to the Central District Ground Water Section. A completed Certification Page shall accompany each quarter of monitoring data. The quarterly ground water monitoring results shall be submitted with the DMR as shown in the following schedule:

SAMPLE PERIOD	REPORT DUE DATE
January - March	April 28
April - June	July 28
July - September	October 28
October - December	January 28

IV. Other Land Application Requirements

1. This section is not applicable to this facility.

V. Operation and Maintenance Requirements

A. Operation of Treatment and Disposal Facilities

1. The permittee shall ensure that the operation of this facility is as described in the application and supporting documents.

2. The operation of the pollution control facilities described in this permit shall be under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control.

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B. Record keeping Requirements:

1. The permittee shall maintain the following records on the site of the permitted facility and make them available for inspection:

   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, other than those required in items a. and f. of this section, required by the permit for at least three years from the date the report was prepared, unless otherwise specified by Department rule;

   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, unless otherwise specified by Department rule;

   d. A copy of the current permit;

   e. A copy of any required record drawings;

   f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule.

VI. Schedules

1. A Best Management Practices Pollution Prevention (BMP3) Plan shall be prepared and implemented in accordance with Part VII of this permit and the following schedule:

	Action Item	Scheduled Completion Date
1	Continue Implementing Existing BMP3 Plan	Issuance Date of Permit

2. The permittee shall achieve compliance with the other conditions of this permit as follows:

   a. Opertional level attained ..... Issuance Date of Permit

3. The following construction schedule shall be followed:

   a. Relocate Outfall D-030 to I-016 ..... 6 months of Issuance Date of Permit

   b. Submit Certificate of Completion of Construction (See VII.B.1) ..... 30 days of Completion of Construction

   c. Submit Record Drawings (See VII.B.2).....6 months after Completion of Construction

4. Biological Monitoring Program:

   a. Within six 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

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I.E.10, and shall submit the POS within twelve 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 shedule.

5. Additional Intake/Discharge Sampling and Reporting

   a. Within 60 days of permit issuance the permittee shall begin additional sampling to be conducted quarterly for a total of 4 sampling events. Concurrent 24-hour composite samples shall be taken of the intake and from Outfalls D-011, D-012, and D-015 (Sample Points EFF-1, EFF-2, and EFF-3) and analyzed for Copper, Nickel, and Beryllium.

   b. Sampling results shall be submitted to the Department with the next scheduled quarterly report and include results from the sampling events since the last submittal except results submitted for the fourth quarterly report shall include summary results from all 4 sampling events.

   c. Analytical test methods, method detection limits (MDLs), and practical quantification limits (PQLs) shall be in accordance with the requirements of Section I.E.1 of this permit.

   d. If the sampling results indicate a reasonable potential for an exceedance of water quality standards and concentrations in the discharge exceed intake concentrations, taking into account sampling and analytical variations, then the Department may reopen the permit in accordance with Section VII.F.2 of this permit to include different limitations or monitoring requirements or take other action as appropriate.

6. The Permittee shall comply with the requirements of 40 CFR Part 125.95(a)(1) and (2) no later than upon submittal of a timely application for permit renewal, submitted pursuant to the requirements of Condition VII.C. of this permit.

7. No later than 14 calendar days following a date identified in the above schedule(s) of compliance, the permittee shall submit either a report of progress or, in the case of specific actions being required by an identified date, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

VII. Other Specific Conditions

A. Specific Conditions Applicable to All Permits

1. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Northwest District Office, are made a part hereof.

2. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under this permit, shall be signed and sealed by the professional(s) who prepared them.

3. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Specific Conditions Related to Construction

1. Within thirty days of completion of construction, the permittee shall submit to the Department a completed "Certificate of Completion of Construction" (DEP Form 62-620.910(12) signed and sealed by the engineer of record or other engineer registered in the State of Florida.
2. Record drawings shall be prepared and made available in accordance with Rule 62-620.410(6), F.A.C, and the Department of Environmental Protection Guide to wastewater Permitting within six months of placing the facility into operation.

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C. Duty to Reapply

1. The permittee shall submit an application to renew this permit at least 180 days before the expiration date of this permit.

2. The permittee shall apply for renewal of this permit on the appropriate form listed in Rule 62-620.910, F.A.C., and in the manner established in Chapter 62-620, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.

3. An application filed in accordance with subsections 1. and 2. of this part shall be considered timely and sufficient. When an application for renewal of a permit is timely and sufficient, the existing permit shall not expire until the Department has taken final action on the application for renewal or until the last day for seeking judicial review of the agency order or a later date fixed by order of the reviewing court.

4. The late submittal of a renewal application shall be considered timely and sufficient for the purpose of extending the effectiveness of the expiring permit only if it is submitted and made complete before the expiration date.

D. Specific Conditions Related to Best Management Practices/Pollution Prevention Conditions

1. General Conditions

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 Waste Minimization Opportunity Assessment Manual, EPA/625/7-88/003.

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) "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.

(6) "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.

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(7) "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.

(8) "BMP3" means a Best Management Plan incorporating the requirements of 40 CFR § 122.44, Subpart K, plus pollution prevention techniques associated with a Waste Minimization Assessment.

(9) "Waste Minimization Assessment" means a systematic planned procedure with the objective of identifying ways to reduce or eliminate waste.

2. **Best Management Practices/Pollution Prevention Plan**

The permittee shall develop and implement a BMP3 plan 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. The BMP3 plan shall contain the following components:

a. Signatory Authority & Management Responsibilities

The BMP3 plan shall be signed by the permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The BMP3 plan shall be reviewed by the 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 BMP3 plan 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 Department upon request.

The BMP3 plan shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP3 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 BMP3 plan.

b. BMP3 Plan Requirements

(1) Name & description of facility, a map illustrating the location of the facility & adjacent receiving waters, and other maps, plot plans or drawings, as necessary;

(2) 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;

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(3) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;

(4) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and

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 loadings and chemical losses to all wastewater and/or storm water streams as described in Part VII.D.3 of this permit.

If the Permittee elects to develop and implement a WMA, information on plan components can be obtained from the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

(850) 245-8589
(850) 245-8669 -- Fax

d. Best Management Practices & Pollution Prevention Committee Recommended:

A Best Management Practices Committee (Committee) should be established to direct or assist in the implementation of the BMP3 plan. The Committee should be comprised of individuals within the plant organization who are responsible for developing the BMP3 plan and assisting the plant manager in its implementation, monitoring of success, and revision. The activities and responsibilities of the Committee should address all aspects of the facility's BMP3 plan. The scope of responsibilities of the Committee should be described in the plan.

e. Employee Training

Employee training programs shall inform personnel at all levels of responsibility of the components & goals of the BMP3 plan and shall describe employee responsibilities for implementing the plan. Training shall address topics such as good housekeeping, materials management, record keeping & reporting, spill prevention & response, as well as specific waste reduction practices to be employed. Training shall also disclose how individual employees may contribute suggestions concerning the BMP3 plan or suggestions regarding Pollution Prevention. The plan shall identify periodic dates for such training.

f. Plan Development & Implementation

The BMP3 plan shall be implemented upon the effective date of this permit, unless any later dates are specified in this permit. If a WMA is ongoing at the time of development or implementation it may be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time may also be identified in the plan, including a schedule for its implementation.

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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 BMP3 plan shall be developed and maintained at the facility and made available to the Department upon request. The summary shall 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 WMA studies, as well as scheduled WMA activities may 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 Department 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 may be included.

(3) A recommended timetable for the various plan requirements follows:

Timetable for BMP3 Plan:

ELEMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Complete WMA (if appropriate)	6 months
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 BMP3 plan is determined insufficient, the permittee will be notified that the BMP3 plan 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 BMP3 plan 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.

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E. 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.

   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.

F. Reopener Clause

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, or other information show a need for a different limitation or monitoring requirement.

3. The Department may develop a Total Maximum Daily Load (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.

VIII. General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, F.S. Any permit noncompliance constitutes a violation of Chapter 403, F.S., and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1), F.A.C.]*

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2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation 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), F.A.C.]*

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 infringements 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), F.A.C.]*

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), F.A.C.]*

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), F.A.C.]*

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), F.A.C.]*

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), F.A.C.]*

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), F.A.C.]*

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), F.A.C.]

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

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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, Florida Statutes, 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), F.A.C.]*

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), F.A.C.]*

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), F.A.C.]*

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), F.A.C.]*

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 Department approves the transfer. *[62-620.610(14), F.A.C.]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15), F.A.C.]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rule 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting 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), F.A.C.]*

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), F.A.C.]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, 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).

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b. If the permittee monitors any contaminate 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. Any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health (DOH) under Chapter 64E-1, F.A.C., where such certification is required by Rule 62-160.300(4), F.A.C. The laboratory must be certified for any specific method and analyte combination that is used to comply with this permit. For domestic wastewater facilities, the on-site test procedures specified in Rule 62-160.300(4), F.A.C., shall be performed by a laboratory certified test for those parameters or under the direction of an operator certified under Chapter 62-602, F.A.C.
e. Fields activities including on-site tests and sample collection, whether performed by a laboratory or a certified operator, must follow the applicable procedures described in DEP-SOP-001/01 (January 2002). Alternate field procedures and laboratory methods may be used where they have been approved according to the requirements of Rules 62-160.220, 62-160.330, and 62-160.600, F.A.C.
[62-620.610(18), F.A.C.]

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), F.A.C.]*

20. The permittee shall report to the Department's Central District Office 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 untreated or treated 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 Department by calling 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;

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(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 Department's Central District Office 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 Central District Office shall waive the written report.
[62-620.610(20), F.A.C.]

21. The permittee shall report all instances of noncompliance not reported under Conditions VIII. 18 and 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Condition VIII. 20. of this permit. *[62-620.610(21), F.A.C.]*

22. Bypass Provisions.
a. 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 preventative maintenance; and
(3) The permittee submitted notices as required under Condition VIII.22.b. of this permit.
b. 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 Condition VIII.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.
c. 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 Condition VIII.22 a. (1) through (3) of this permit.
d. 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 provision of Condition VIII.22.a. through c. of this permit.
[62-620.610(22), F.A.C.]

23. Upset Provisions
a. 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 Condition VIII.20. of this permit; and
(4) The permittee complied with any remedial measures required under Condition VIII.5. of this permit.
b. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.
c. 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), F.A.C.]

PERMITTEE:

FP&L Cape Canaveral Plant
6000 North U.S. Highway 1
Cocoa, FL 32927

PERMIT NUMBER: FL0001473

Issuance date: August 10, 2005
Expiration date: August 9, 2010

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

Mimi A. Drew
Director, Division of Water Resource Management

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

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 Cape Canaveral Power Plant
Manatee Protection Plan

DEP Permit No. FL0001473
Brevard County

Mr. Ron Hix
FPL-SES/JB
Florida Power & Light Company (FPL)
P. O. Box 14000
Juno Beach, FL 33408

NOTICE OF AGENCY ACTION

The Department of Environmental Protection hereby gives notice of its approval of the enclosed Manatee Protection Plan for the FPL Cape Canaveral Plant, dated August 8, 2000. The Manatee Protection Plan was completed pursuant to Specific Condition 13 of the above referenced permit.

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;

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 16
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-11) (Previously RRL-7)
DATE 11/02/09

(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

Mirni 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 12-21-00 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.

S. Shilds 12-21-00
(Clerk) (Date)

Copies furnished to:

Kipp Frohlich, FWC Tallahassee
Chairman, Board of Brevard County Commissioners
Jim Valade, U.S. Fish and Wildlife Service
Save the Manatee Club
Christianne Ferraro, DEP Orlando
Betsy Hewitt, DEP Office of General Counsel

Florida Power & Light - Cape Canaveral Plant
Manatee Protection Plan
(August 8, 2000)

Purpose:

The purpose of the Cape Canaveral Plant Manatee Protection Plan is to set forth Florida Power & Light Company's (FPL) procedures to comply with Specific Condition 13 of the facility's State Industrial Wastewater Permit Number FL0001473 that was issued on February 24, 1999. This Specific Condition reads, in part:

13. 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 13:

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 13, FPL will take the following actions:

    a) In the case of an unplanned shutdown or a plant failure occurring that will affect the warm water refuge from November 15 through March 31, when the ambient water temperature is below 61°F., the Florida Fish and Wildlife Conservation Commission (FWCC) and USFWS will be notified no later than four (4) hours after the event has occurred. If an unplanned shutdown occurs that is expected to result in no thermal discharge for 24 hours or longer, regardless of ambient water temperature, the Florida Marine Research Institute should be notified.

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: (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 area 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 area 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., as measured at the plant intake, the FPL Cape Canaveral plant shall endeavor to operate in a manner that maintains the water temperature in an adequate portion of the discharge area, for at least one unit, at or above 68°F., until such time as the intake 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 Cape Canaveral power plant will provide personnel from the BPSM, USFWS, Florida Marine Research Institute, USGS-Sirenia Project, or a designee of these agencies, access to the FPL Cape Canaveral power plant property to conduct manatee research or 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 area 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 Cape Canaveral power plant.

d) Intake Area: No special surveys will be required for the intake area.

Discharge Area: No special surveys will be required for the discharge area.

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 Cape Canaveral facility. The continuation of the ongoing statewide aerial survey that FPL has funded in the past years meets these criteria.

g) The FPL Cape Canaveral 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 are conducted on a one-time basis unless there are significant physical or operational changes to the FPL Cape Canaveral 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 discharge pipes.
2. Proximate streams, rivers, bays, etc.
3. The location of the condenser inlet and outlet temperature monitoring devices.
4. The location of any fuel barge docking facilities in relation to the discharge area.
5. The delineation of the no-entry boundary at the discharge area.

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 Cape Canaveral 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 area waters, as well as its gross bathymetry, at the mean rate of discharge when the ambient water temperature reaches a seasonal low.

Note: The "Thermal Analysis" conducted by FPL in January, 1996 and submitted to the FWCC meets the first requirement above ("... provide a profile of the thermal gradient (either actual or calculated) of the discharge area waters...").

FLORIDA POWER & LIGHT – CAPE CANAVERAL POWER 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 Wildlife Conservation Commission at 1-888-404-FWCC (1-888-404-3922). Collision and/or injury should also be reported to the U.S. Fish and Wildlife Service in Jacksonville (1-904-232-2580).

United States Department of the Interior

FISH AND WILDLIFE SERVICE
6620 Southpoint Drive, South
Suite 310
Jacksonville, Florida 32216-0912

IN REPLY REFER TO:

June 24, 2008

Randall LaBauve, Director
Environmental Services
Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Dear Mr LaBauve:

The U. S. Fish and Wildlife Service (Service) appreciates Florida Power and Light Company's (FP&L) efforts to notify us, the Florida Fish and Wildlife Conservation Commission (FWC), and others about plans to repower the Canaveral and Riviera Beach power plants and company concerns regarding manatees known to use these sites.

Repowering efforts will involve closing the plants for extended periods of time during demolition and construction activities, a process that will ultimately extend the plant's operational lifespan, as well as the associated warm water discharges. The shutdowns will include temporarily eliminating the warm water discharges from each site during the winter when they are typically used by hundreds of manatees.

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. Therefore, it is critical that you minimize impacts and take steps to avoid the loss of any manatees during your transition process, as well as insure that there is no loss of manatee wintering habitat in both the near and long term.

For planning purposes, we recommend that your plan designs include identifying baseline information about the extent of warm water habitat currently used by manatees at both plants. This could include measuring the areas of warm water habitat, discharge temperatures, discharge volumes, and other parameters. The same or similar quantities of habitat will need to be provided at or in close enough proximity to these sites, such that manatees are able to find and use it with minimal disruption. In addition, any locations should include protections from human disturbance, similar to those which are currently in place. Finally, contingency plans currently under development by FWC, the Service, FP&L and others, should be completed and operational during the transition in the event that manatees do not respond as expected.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 17
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-12) (Previously RRL-8)
DATE 11/02/09

FP&L 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. We look forward to working with you on this important issue, and would appreciate an opportunity to meet with you to discuss this further. Please do not hesitate to contact us if you have any questions or concerns.

Sincerely,

Dave Hankla
Field Supervisor

CC: Sam Hamilton, Regional Director, Atlanta, Georgia
Ken Haddad, Director, Florida Fish and Wildlife Conservation Commission, Tallahassee, Fl

FWC STAFF REPORT FOR FLORIDA POWER AND LIGHT COMPANY – CAPE CANAVERAL ENERGY CENTER (CCEC)

Prepared by Jennifer Goff and Ron Mezich, Fish and Wildlife Biologists, July 6, 2009

This report summarizes the fish and wildlife resources that could be affected by changes to the existing power plant. It includes general recommendations for addressing these issues during the development. If you have any questions regarding the information in this report, please do not hesitate to contact Jennifer Goff at phone (561) 625-5122, or email at Jennifer.Goff@myfwc.com, or Ron Mezich at phone (850) 922-4330 or email at Ron.Mezich@myfwc.com.

PROJECT DESCRIPTION

The existing Florida Power and Light (FPL) Cape Canaveral Plan consists of two nominal 400-megawat unit conventional dual-fuel fired steam boilers that will be converted into a "modern, highly efficient, lower-emission next-generation energy center" (p. 1-1 of volume 1 of the application submittal). The project will use existing plant site boundaries, cooling water intake and discharge infrastructure, and transmission right-of-way. Construction parking and laydown will be staged on FPL-owned land adjacent to the existing Cape Canaveral Plant. The existing FPL Cape Canaveral Plant property is located on approximately 43 acres of flat, sandy area between Cocoa and Titusville in Brevard County, Florida. The site is bounded on the east by the Indian River Lagoon (Intercoastal Waterway) and on the west by U.S. Highway 1 in a portion of Section 19, Township 23, and Range 36. In addition, FPL maintains a sovereignty submerge lands lease from Florida Department of Environmental Protection (DEP) that is identified as tax Parcel Identification number 23-36-19-00-00750.0-0000.0.

The proposal utilizes the existing plant site boundaries, cooling water intake and discharge infrastructure, and transmission right-of-way. Construction parking and laydown would be staged on FPL-owned land adjacent to the existing Cape Canaveral Plant. While there would be no permanent changes in the actual footprint of the facility, this proposal requires the addition of an offsite construction laydown and parking area, and a minor upgrade to existing transmission lines/switchyard/substation to connect Cape Canaveral Energy Center (CCEC) to the FPL transmission system. Temporary changes to the thermal discharge would occur during the conversion, while the conversion would yield a permanent reduction in the CCEC's thermal discharge. The interim discharges would be to the existing intake canal located approximately 500 feet south of the current warm-water discharge area. After the conversion, the CCEC's expected thermal discharge would be approximately 25% less than at present.

POTENTIALLY AFFECTED RESOURCES

Terrestrial wildlife

This CCEC proposal does not require any permanent increase of the footprints of the associated facilities, but does propose to clear approximatelv 41 acres for offsite

construction laydown and parking area. The proposed location for these activities contains flat, sandy soils and large areas of upland scrub, pine, and hardwood hammock habitat. There are several species on the State's threatened list that occur in this area including the gopher tortoise, Florida scrub-jay, eastern indigo snake, and Florida beach mouse and these conditions help address our concerns in regards to those species.

West Indian manatee

The manatee is listed by both the State and the USFWS as Endangered, and its use of the area surrounding the CCEC is well documented by aerial survey, mortality, and satellite telemetry data. The project site is characterized as a primary warm-water manatee refuge site due to the presence of a warm-water effluent from power plant operations. Between January 1974 and December 2008, 36 manatees have died from watercraft-related causes within a five-mile radius of the project location. In addition to the watercraft-related deaths, there have also been eight human-other, 26 perinatal, 26 cold-stress, 45 natural (other), and 68 undetermined manatee deaths within the same radius.

Historically speaking, the majority of manatees on the east coast of Florida are believed to have been limited in their distribution during cold winters to the warmer sub-tropical waters south of the Sebastian River (Moore 1951). Because of their limited ability to conserve heat, manatees cannot survive exposure to water temperatures below approximately 68° F (20°C) for extended periods of time (Marine Mammal Commission 1988). In north and central Florida, water temperatures in winter periodically drop below 68° F. During these periods, manatees seek out warm-water sources. The power plants and other industries that discharge large volumes of warm water into Florida's coastal bays and estuaries provide manatees with warm-water refugia (Campbell and Irvine 1981, O'Shea et al. 1985). Since the introduction of these warm-water sources, more manatees have used Brevard County waters during the winter months.

With the presence of a warm-water refuge, ample forage, and protected areas in the north Banana River, Brevard County hosts a significant year-round manatee population. Spring and winter aggregations are the largest documented in the State. Spring aggregations in the north Banana River alone have exceeded 365 manatees (Jane Provancha, personal communication), while winter surveys at thermal discharges from the two power plants in Brevard County have documented a high count of 588 manatees during a single flight (Reynolds 2004).

The conversion of the CCEC would result in the temporary discontinuation of the existing thermal discharge and manatee warm-water refuge; however, the construction of an interim heating system would allow for continuation of a warm-water refuge for manatees near the CCEC. The temporary discontinuation of the existing thermal discharge and the relocation of the warm-water refuge to a nearby location will modify manatee warm-water habitat and require manatees to adapt to this change.

Due to the dependence of numerous manatees on the warm-water habitat provided by the CCEC, permit conditions addressing the interim heating system, the temporary warm-water refuge, and the return to the historic site after reconstruction are being

recommended. In addition, FWC is also recommending that FPL provide for monitoring of environmental and biological indicators that will play a substantial role in determining the status of the interim heating system during the conversion. These monitoring conditions will assist FWC's efforts to monitor the health status of manatees and provide an early warning system for cold stress complications and contingency planning to help mitigate the potential loss of significant numbers of manatees if there is a failure in the interim warm-water heating system.

Conclusion - Manatees

Florida manatees have used the Cape Canaveral plant's thermal discharge during the winter months for decades. The thermal discharge from this plant has been consistent and reliable, thereby allowing manatees to become dependent on it. At the time the Manatee Power Plant Protection Plan (MPPPP) was developed for this plant, the FWC, USFWS, and FPL agreed upon a 61°F ambient water trigger temperature based on a negotiation of several factors. This trigger temperature requires the plant to operate at least one unit to create a warm-water refuge for manatees during the winter months when ambient water temperatures reach the trigger temperature. The ambient water temperature that was selected was based on several criteria: 1) Base Load Operation, with the Cape Canaveral Plant operating as a base load unit (running consistently and creating a dependable warm-water refuge), 2) economics (potential costs to FPL) and 3) manatee biology (how often and how long would manatees be subjected to temperatures between 68°F and 61°F). Two of these three factors have recently changed and will change even further during the conversion process. The warm water discharge at the Cape Canaveral Plant has been less consistent, and the interim refuge may be even less dependable for manatees if operated at a 61° F trigger temperature. The reduced dependability of the warm-water refuge may increase the frequency of exposure of manatees to cold water and escalate the risk of cold stress disease and death since the proposed interim heating system has not been implemented previously.

The USFWS advised the licensee in August 2008 that take of manatees is not authorized during the proposed plant conversion at the CCEC (See Attachment A). As a result FWC has attempted to develop appropriate measures and conditions to prevent take of manatees during reconstruction of the plant, which includes the interim refuge. We have worked as closely as possible with the licensee to develop these conditions.

RECOMMENDATIONS

We recommend the following Conditions of Certification:

Terrestrial Wildlife

1. All undeveloped habitat onsite shall be surveyed for the presence of state- and federally listed species no more than six months before land clearing and the results shall be reported to the FWC. We recommend that the report includes methodology, results, discussion, and references to all survey protocols and documents used. If there is evidence that any state-listed species are present, then the licensee must report the findings to the FWC. If impacts to those species cannot be avoided, then the licensee must contact the FWC before taking any action that might result in an impact to those species.

2. Gopher tortoises found onsite shall be relocated in accordance with the state Gopher Tortoise Management Plan. Pursuant to the requirements of Rules 68A-25.002 and 68A-27.004, Florida Administrative Code, a permit for a gopher tortoise capture/relocation/release activity must be secured from the FWC before beginning any relocation work. Such permits will be issued pursuant to any and all applications which sufficiently accommodate these guidelines. Application forms to be used are available from the Permit Coordinator, Species Conservation Planning Section, Florida Fish and Wildlife Conservation Commission, 620 S. Meridian St., Mail Station 2A, Tallahassee, FL 32399-1600, (850)410-0656, ext. 17327/ (850)488-5297 fax or from the FWC's web site at http://myfwc.com/permits/Protected-Wildlife/. Complete applications should be submitted to the Gopher Tortoise Permit Coordinator at the above address at least 45 days before the time needed.

3. Before clearing, FPL shall coordinate with the USFWS and the FWC regarding appropriate measures to address impacts to scrub-jay habitat.

   [Article IV, Sec. 9, Fla. Const.; Chapter 68A-27, F.A.C.]

West Indian Manatee

Interim Warm-Water Refuge Heating System

4. The current trigger temperature identified in the Manatee Protection Plan under the Cape Canaveral power plant's National Pollutant Discharge Elimination System permit is 61°F. In order to prevent an increased risk of manatee cold stress death during the CCEC conversion construction period, adaptive management protocols for the interim warm-water refuge heating system shall include the following:

   a. Testing, monitoring, and evaluation of the interim heating system shall take place pursuant to the permit conditions found in the Environmental Monitoring and Biological sections.

b. The trigger temperature shall be set at 65°F, during the period that the interim heating system is required. The interim heating system shall be designed such that when ambient water temperatures are below 65°F, as indicated from a selected ambient water temperature station (as agreed to in the environmental monitoring plan), the interim heating system will provide a water temperature at or above 68°F, within the identified warm-water refuge until such time as the ambient water temperature reaches 65°F. The interim heating system shall be maintained and operated to achieve this result, in accordance with best management practices (BMP) established by Licensee, unless otherwise authorized by FWC and USFWS, or unless the safety or reliability of the electric power system would be compromised. Licensee shall develop a BMP manual for the interim heating system that shall include the following components:

   i. operation and maintenance procedures for the interim heating system;
   ii. requirement for a log demonstrating that the recommended operating and maintenance procedures and checks are performed;
   iii. a spare parts list including the location of the spares;
   iv a list of qualified operators and repair persons and their contact information;
   iv. a trouble shooting flowchart and repair personnel call out plan;
   v. an incident log to track the status of troubleshooting and repair activities until the system is operable;
   vi. notification requirements to agencies.

   Licensee shall submit its BMP manual to FWC for review and comment by August 15, 2010. Licensee will review, consider, and incorporate if practicable, comments from FWC that are received by September 15, 2010. A copy of the Licensee's BMP manual for the interim heating system shall be maintained at all times at the CCEC site and shall be made available upon request to authorized representatives of FWC and DEP.

c. If through the biological monitoring or daily visual assessments of manatee health, or scientific data it is indicated, that the 65°F interim heating system trigger temperature should be; raised or lowered to maintain a sufficient warm-water refuge, then DEP will meet with FWC, USFWS, and FPL to assess the information and develop a new strategy that can be agreed upon by all four parties. Such a new agreed upon strategy would be proposed in a DEP initiated modification to certification, in consultation with FWC, USFWS and FPL.

d. The interim warm-water refuge is described as the area located within the current Cape Canaveral plant intake canal beginning at the western most extent of the canal and including all waters within the canal between the peninsula and the southern shoreline up to the southern shoreline's eastern most point (See attachment B and C).

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Section 253.75 F.S., Rules 68A-27 Florida Administrative Code.]

The Licensee may request modification of the following applicable FWC conditions upon issuance by the Department of Environmental Protection, in consultation with the FWC, of Final NPDES permit modification FL0001473 if such requested modifications to the conditions herein have been adopted into the Final NPDES permit.

Environmental Monitoring

5. The following monitoring requirements are applicable to the interim warm-water refuge period and two years post commercial operation of CCE-C:

    a. Within 180 days following certification of the CCEC, the Licensee (Florida Power & Light Company) shall submit to the FWC, Florida Department of Environmental Protection (DEP) Siting Office, and the USFWS an Environmental Monitoring Plan. The Environmental Monitoring Plan shall include, at a minimum, the following components:

        i. An evaluation of the interim heating system to determine its ability to provide a sufficient manatee warm-water refuge (as described in conditions 4 and 5, and the Licensee's Thermal Modeling Study) during the winter months shall take place prior to discontinuation of the current warm-water discharge. Evaluation of the system shall include its performance during cold fronts and varying tidal and wind conditions, if present, for a duration to be established in the Environmental Monitoring Plan.

        ii. If an interim heating system is installed at Riviera Beach Energy Center (RBEC) in 2009 an initial evaluation of the interim heating system, during winter conditions, shall be conducted there.

        iii. The interim heating system at the CCEC site shall be installed and operational by September 15, 2010 or as soon as practicable after certification, whichever is later. However, the conversion from the existing system to the interim system cannot be implemented during the winter months (November through March). The warm-water refuge created by this system shall be monitored during initial testing at the CCEC site between September 15 and October 15, 2010, or the duration described in 5.a.i. and the empirical temperature data will be collected and compared to the thermal modeling results to evaluate the performance of the interim heating system and the accuracy of the thermal model.

        iv. Monitoring of the CCEC's interim warm-water refuge during the conversion shall consist of winter (October 15 through March 31)

ambient air and water temperatures measured at multiple locations within the interim warm-water refuge. The number and configuration of temperature monitoring stations must be sufficient to provide a three-dimensional view, over time, of the thermal plume.

v. Monitoring of the CCEC's post-conversion warm-water refuge shall consist of winter ambient air and water temperatures measured at multiple locations within the warm-water refuge. Monitoring for the first post conversion winter shall take place from October 15 through March 31 and from November 15 through March 31 during the second winter post construction. The number and configuration of temperature monitoring stations must be sufficient to provide a three-dimensional view, over time, of the thermal plume.

vi. Temperature monitoring stations will be deployed during the conversion phase in the interim refuge and post-conversion warm-water refuge. As part of this Environmental Monitoring Plan as described in this Section 5., the Licensee shall include a plan to convey the data from the temperature monitoring stations to the appropriate agencies on a daily basis when the trigger is on and the heaters are running and on a weekly basis when the ambient temperature is greater than 65 degrees.

vii. Specific locations for the temperature monitoring station(s), sampling frequencies, station depths data collection methods, and reporting frequencies must be identified and may be subject to further revision depending on receipt of any required permits, licenses and approvals.

viii. The Environmental Monitoring Plan, including the proposed monitoring locations, shall be approved prior to implementation. DEP, in consultation with the FWC and USFWS, shall indicate its approval or disapproval of the submitted plan within 90 days of the originally submitted information. In the event that additional information from the licensee is necessary to complete and approve the Plan, DEP, in consultation with the FWC and USFWS, shall make a written request to the licensee for additional information no later than 30 days after receipt of the submitted information. A final plan shall be in place by September 1, 2010.

b. The Licensee will prepare an environmental monitoring report that includes all data (made available in electronic form) and statistical analyses collected as a result of the environmental monitoring requirements. This report will be submitted yearly, by August 1 of each year, while the interim warm-water system is in operation during the construction period and two years post-conversion of the CCEC. Within 180 days of the submittal of the final yearly environmental monitoring

report, a summary report of all environmental monitoring shall be completed and submitted to the FWC, and DEP Siting Office for review.

c. If, in the review of the annual environmental monitoring reports, DEP, in consultation with the FWC and USFWS, determines the need to modify the Environmental Monitoring Plan, DEP will notify the Licensee to discuss the findings. At that time, DEP, in consultation with the FWC and USFWS and the Licensee, will determine what, if any, modifications need to be made to the Environmental Monitoring Plan and DEP will initiate modifications to certification if necessary.

d. If by June 1, 2010, the initial monitoring tests of the interim warm-water heating system have taken place at the Riviera Beach power plant, the Licensee will contact DEP and FWC to provide and discuss the results. At that time, DEP, in consultation with the FWC and USFWS, and the Licensee, will determine what, if any, modifications need to be made to the operation of the interim heating systems and DEP will initiate a modification to certification if necessary.

e. By November 1, 2010, or two weeks after completion of the initial monitoring test of the interim warm-water heating system at the CCEC, the Licensee will contact DEP, FWC and USFWS to provide and discuss the results. At that time, DEP, in consultation with the FWC, USFWS, and the Licensee, will determine what, if any, modifications need to be made to the operation of the interim heating system and DEP will initiate a modification to certification if necessary.

f. If the Licensee determines the Environmental Monitoring Plan is in need of modifications during the operation of the interim heating system, the Licensee will contact the agencies to discuss the proposed modifications. At that time, DEP, in consultation with the FWC and USFWS and the Licensee, will determine what if any modifications need to be made to the Environmental Monitoring Plan and the DEP shall initiate a modification to certification if necessary.

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Section 253.75 F.S., Rules 68A-27 Florida Administrative Code.]

Biological Monitoring

6. The following monitoring requirements for manatee distribution and abundance are applicable to the interim warm-water refuge and two year post-commercial operation of CCEC:

a. Within 180 days following certification of the CCEC, the Licensee shall submit to the DEP Siting Office and FWC, a Biological Monitoring Plan. The Biological Monitoring Plan shall include at a minimum the following components:

   i. Monitor the winter (October 15 through March 31) distribution and abundance of manatees during the time frame that includes the operation of the interim warm-water heating system. Monitor the winter (November 15 through March 31) distribution and abundance of manatees during the two years' post-conversion at the CCEC warm-water refuge.

   ii. Biological monitoring shall at a minimum be conducted through aerial surveys and telemetry tagged manatees.

   iii. Specific aerial survey paths, sampling frequencies, and methodologies for aerial surveys. At a minimum, aerial survey flight paths shall encompass known manatee winter habitat including travel corridors and passive warm-water sites throughout Brevard County on a weekly basis during the interim period during the winter months (October 15 through March 31). Once the converted CCEC is in operation the aerial surveys shall be conducted on a twice a month basis for two years post commercial operation during the winter months. After the first year of post conversion surveys FWC will discuss the results with the Licensee and determine if the second year's surveys can be reduced to one survey per month.

   iv. Aerial surveys shall be designed so the data collected will provide an evaluation of manatee abundance and distributional changes in Brevard County in a statistically valid manner that is consistent with past aerial survey data.

   v. Telemetry monitoring shall be accomplished by the Licensee through the use of FWC or another entity with experience in manatee telemetry tracking, and data analysis in Florida by providing them $50,000 per winter season to be used for the purchase of up to three tags annually, if needed, and the accompanying annual activities and research, tracking and monitoring activities, data collection, ARGOS usage, software purchase and update, and one final report to the Licensee. This condition will coincide with the use of the interim heating system and 2 years post-commercial operation of CCEC. After the first year of post conversion telemetry monitoring FWC will discuss the results with the Licensee and the parties will determine if the second year's monitoring can be eliminated. The tags will be attached to manatees captured at, or near the CCEC site to document their movements to secondary warm-water sites, nighttime habitat use, behavioral response to changes in the operation of the interim refuge (e.g., availability of warm-water

discharge in relation to the trigger temperature), and thermal regime experienced by manatees during the conversion of CCEC. The details of the telemetry effort will be provided in the biological monitoring plan and, if requested by the licensee, FWC and USFWS can provide assistance.

vi. The Biological Monitoring Plan shall be reviewed and approved prior to implementation. DEP, in consultation with the FWC and USFWS, shall indicate its approval or disapproval of the submitted plan within 90 days of the originally submitted information. In the event that additional information from the licensee is necessary to complete and approve the Plan, DEP, in consultation with the FWC and USFWS, shall make a written request to the Licensee for additional information no later than 30 days after receipt of the submitted information. A final plan shall be in place by September 1, 2010.

b. The Licensee shall provide a manatee observer(s) who has sufficient experience in detecting indicators of cold stress in manatees. The monitoring protocols and individuals acting as manatee observer(s) will require approval from the FWC.

c. The manatee observer will be required to conduct a daily visual assessment of the condition and general distribution of manatees using the interim warm-water refuge during the winter months (October 15 through March 31) during the interim period. The visual assessments shall be conducted for a sufficient length of time to assess most of the manatees present at the plant and accessible to the observer on that day. If an approved observer is not available, licensee shall notify FWC as soon as possible, but no later than 48 hours, to coordinate actions necessary to resume the observation program.

d. The Licensee shall provide two moveable land-based observation platforms located along the interim warm-water refuge. These will be used by the manatee observer(s) for conducting assessments of cold stress symptoms and by FWC or USFWS staff monitoring manatee use of the interim refuge through photo identification.

e. The Licensee will prepare a biological monitoring report that includes all data (made available in electronic form) and statistical analyses completed as a result of the requirements set forth in the biological monitoring plan. This report will be submitted yearly, by August 1 of each year, when the interim warm-water system is in operation during the construction period and two years post-commercial operation date. Within 180 days of submittal of the final yearly biological monitoring report a summary of all biological monitoring reports shall be completed and submitted to the FWC and DEP Siting Office for review.

f. If, in the review of the biological monitoring reports, DEP, in consultation with FWC and USFWS, determines the need to modify the Biological Monitoring Plan, DEP will notify the Licensee to discuss the findings. At that time, DEP, in consultation with the FWC and USFWS, and the Licensee will determine what if any modifications need to be made to the Biological Monitoring Plan and the DEP will initiate a modification to certification if necessary.

g. If the Licensee determines the Biological Monitoring Plan is in need of modifications during the operation of the interim heating system, the Licensee will contact the agencies to discuss the proposed modifications. At that time, DEP, in consultation with the FWC and USFWS, and the Licensee will determine what, if any modifications need to be made to the Biological Monitoring Plan and the DEP will initiate a modification to certification if necessary.

h. The Licensee will provide personnel from the FWC, USFWS, USGS Sirenia Project, or a designee of these agencies, access to the CCEC property to conduct manatee monitoring activities. Reasonable notice shall be given to the Licensee by the agencies. Access would be limited to normal weekday business hours (8:00 a.m. - 5:00 p.m.) unless arrangements are made in advance with the Licensee.

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Section 253.75 F.S., Rules 68A-27 Florida Administrative Code.]

Contingency Plan

7. FWC and USFWS' LOA (Letter of Authorization) network responders will be responsible for all efforts related to manatee rescues, rehabilitation activities, and carcass recovery during the CCEC conversion. In order to effectively implement contingency plans during the plant conversion and to address manatee health-related issues due to a malfunction or inability of the interim warm-water heating system to effectively provide a warm-water refuge during the winter months (October 15 through March 31), the following conditions are required:

   a. If the observer (pursuant to conditions 6.b., c. and d.) identifies manatees with apparent signs of cold stress disease, digital photographs should be taken of the animal(s) and the FWC shall be called as soon as possible on the day of the observations through the following methods. An FWC biologist can be reached via pager at 800-714-0620 (enter the callers contact number followed by the code "02". A page will be returned within 30 minutes; if not, resend the page. For immediate emergency situations FWC's Wildlife Alert number can also be called at 888-404-FWCC.

b. The Licensee will notify FWC and USFWS immediately if there is a mechanical failure of the interim heating system, or if, for any other reason the interim heating system is not operating in a manner that will provide warm-water sufficient to keep the warm-water refuge at a temperature of 68° F or greater.

c. The Licensee shall provide in-kind services and financial assistance, not to exceed $100,000 in total value, to FWC for manatee rescue or recovery in the event that there is a failure of the interim heating system resulting from Licensee's failure to comply with Condition 4.b. that causes death or identifiable cold stress to manatees in Brevard County. This condition would apply during the winter months (October 15 through March 31). The in-kind assistance and funds would only be used to address manatee-related cold stress issues in the area that the interim system affects.

d. The Licensee will provide personnel from the FWC, USFWS, USGS-Sirenia Project, or a designee of these agencies, access to the CCEC property to conduct manatee monitoring activities. Reasonable notice shall be given to the licensee by the agencies. Access would be limited to normal weekday business hours (8:00 a.m. - 5:00 p.m.) unless arrangements are made in advance with the Licensee.

e. The Licensee will include as part of its safety orientation manatee awareness training for full-time permanent construction personnel at the CCEC site. This training will be designed to educate the construction work force about the legal requirements to avoid manatees and to provide them with contact information if they should spot an injured manatee.

f. All visitors to CCEC will be required to comply with FPL's safety and security requirements. Personnel will receive an orientation from FPL or its contractor prior to commencing observations or other activities.

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Rules 68A-27 Florida Administrative Code.]

Development of a Long-Term Manatee Strategy

8. It is expected that at some point in the future the warm-water habitat created by the CCEC will diminish or be terminated in that event the FWC and USFWS believes it is in the best interest of the Licensee, FWC, USFWS, DEP, and the Florida manatee population to begin strategic long term planning to reduce the adverse affects to the Florida manatee population before this occurs.

   a. Within two years of the formal approval by FWC and USFWS of a Warm-Water Action Plan (Plan), inclusive of a future-oriented Management Policy for Warm-Water Manatee Habitat, the Licensee shall host and chair

a workshop designed to: (a) articulate a strategy for achieving the goals of that Plan, (b) develop a timetable for implementing the strategy, (c) review progress to date in achieving the strategy, and (d) identify impediments and solutions.

b. Within one year of the workshop held pursuant to Condition 1, the Licensee shall provide the FWC and USFWS with a formal report of the workshop, including findings, conclusions, and recommendations.

c. Over the course of the operating life span of the CCEC the Licensee shall develop an exit strategy for the CCEC that prevents significant losses to the manatee population when the Licensee determines reduce or eliminate the CCEC's thermal discharge to the extent that a dependable warm-water refuge is no longer present. The Licensee's strategy shall consider FWC and USFWS's statewide Warm-Water Action Plan approved by FWC and USFWS.

d. The Licensee shall work closely with the FWC and USFWS to evaluate progress toward achieving the vision and goals of the Warm-Water Action Plan and to develop adaptive changes to the Plan as needed to promote manatee recovery through participation in periodic workshops and/or conferences designed to accomplish such evaluation and adaptive changes.

Manatee Construction Conditions For In-Water Work

9. The Standard Manatee Conditions for In-Water Work (revision 2009) are required for all in-water work in or adjacent to waters accessible to manatees. Blasting or pile hammering activities to break rock shall be prohibited in waters accessible to manatees. If no other alternative exists, a modification of these conservation measures can be requested. An adequate Blast and Protected Species Watch Plan must be submitted to and approved by the Imperiled Species Management Section of the FWC prior to these methodologies being used.

10. To reduce the possibility of injuring or killing a manatee during construction, in-water work shall not be performed between November 15 and March 31 unless essential to support the CCEC project's schedule. If in-water work during the winter cannot be avoided the Licensee will contact the agencies to determine alternative conditions that will be implemented to address the proposed activity.

11. At least one person shall be designated as a manatee observer when in-water work is being performed. That person shall have experience in manatee observation, be approved by the FWC two weeks before the beginning of construction, and be equipped with polarized sunglasses to aid in observation. The manatee observer must be on site during all in-water construction activities and will advise personnel to cease operation upon sighting a manatee within 50 feet of any in-water construction activity. Movement of a work barge, other

associated vessels, or any in-water work shall not be performed after sunset, when the possibility of spotting manatees is negligible. Observers shall maintain a log detailing manatee sightings, work stoppages, and other protected species-related incidents. A report, summarizing all activities noted in the observer logs, the location and name of project, and the dates and times of work shall be submitted within 30 days following project completion, to the FWC's Imperiled Species Management Section at: 620 South Meridian Street, 6A, Tallahassee, Florida 32399-1600, or e-mailed at fcmpmail@myfwc.com.

To reduce the risk of entrapment and drowning of manatees, grating shall be installed over any existing or proposed pipes or culverts greater than 8 inches, but smaller than 8 feet in diameter that are submerged or partially submerged and reasonably accessible to manatees. Bars or grates no more than 8 inches apart shall be placed on the accessible end(s) during all phases of the construction process and as a final design element to restrict manatee access.

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Rules 68A-27 Florida Administrative Code.]

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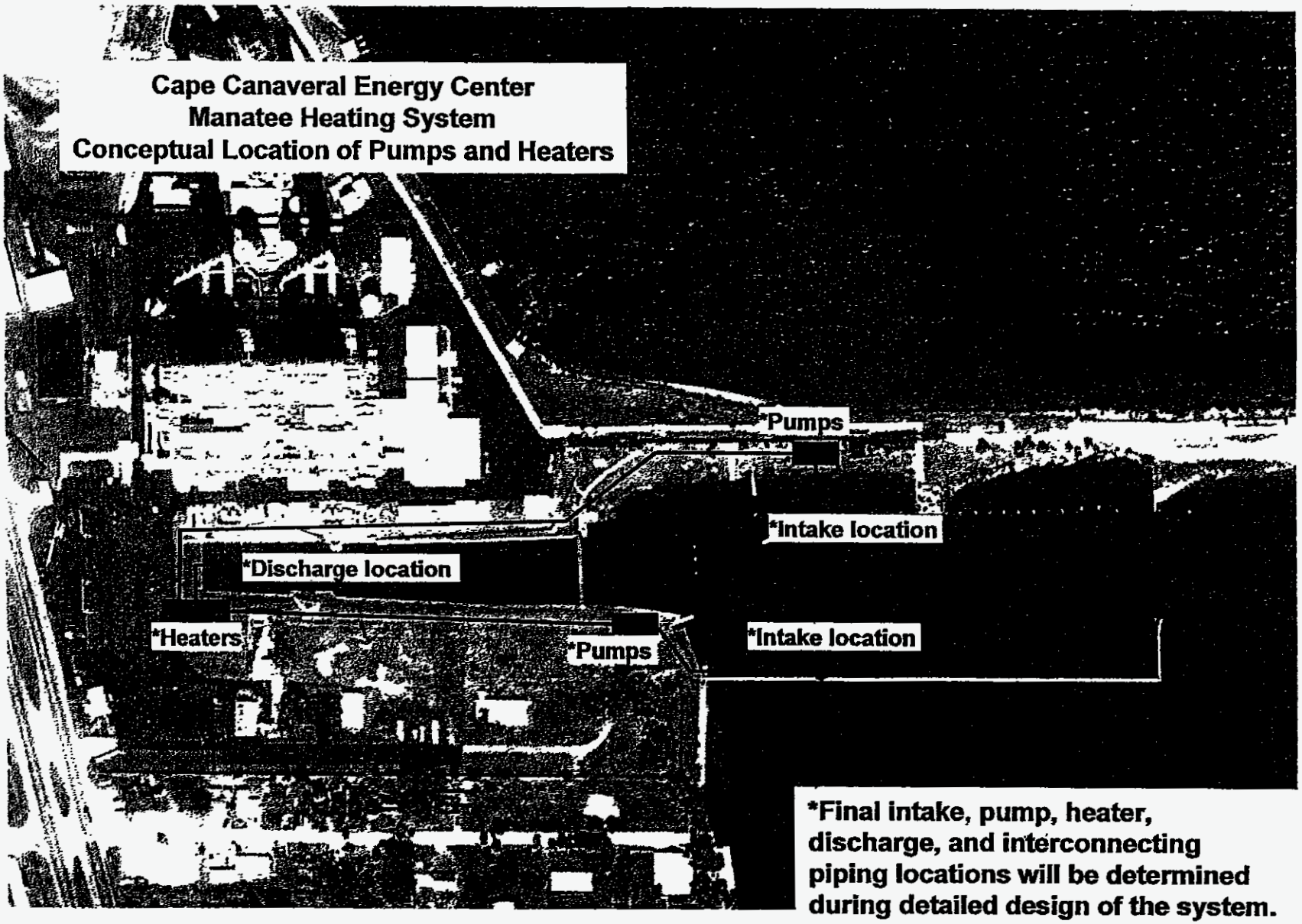
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Reynolds, J.E., III. 2004. Distribution and Abundance of Florida Manatees (*Trichechus manatus latirostris)* Around Selected Power Plants Following Winter Cold Fronts. 2002-2003. Final Report Prepared For FP&L Company, Juno Beach, FL. Order Number 4500004663: 48 pp.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 19
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-14) (Previously RRL-10)
DATE 11/02/09



Docket No. 090007- EI
Manatee Heating System Conceptual Location of Pumps and Heater
Exhibit RRL-14, Page 1 of 1

EXHIBIT 1 (WG-1)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1A THROUGH 42-8A

JANUARY 2008 - DECEMBER 2008
FINAL TRUE-UP
DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 20
COMPANY Progress Energy Florida, Inc.
WITNESS Will Garrett (WG-1)
DATE 11/02/09

Form 42-1A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2008 through December 2008 (Form 42-2A, Line 5 + 6 + 7 + 11)	$ (14,193,035)
2	Estimated/Actual True-Up Amount approved for the period January 2008 through December 2008 (Order No. PSC-08-0775-FOF-EI)	(9,872,429)
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2010 to December 2010 (Lines 1 - 2)	**$ (4,320,606)**

Form 42-2A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$3,064,100	$2,828,489	$2,803,681	$2,981,102	$3,193,738	$3,940,477	$3,744,710	$4,053,314	$4,406,756	$3,468,274	$3,183,014	$3,509,067	$41,176,721
2	True-Up Provision	($886,816)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(886,816)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		2,990,199	2,754,588	2,729,779	2,907,200	3,119,837	3,866,576	3,670,809	3,979,413	4,332,855	3,394,372	3,109,112	3,435,165	40,289,905
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		2,910,716	2,908,273	3,793,525	3,692,843	3,874,070	4,308,114	4,399,539	4,477,670	3,345,481	2,894,941	2,236,403	3,049,480	41,891,055
	b. Capital Investment Projects (Form 42-7A, Line 9)		626,711	854,785	725,996	912,241	1,058,163	1,168,028	1,188,324	1,187,205	1,187,536	1,185,334	1,199,029	1,246,031	12,539,382
	c. Total Jurisdictional ECRC Costs		3,537,427	3,763,058	4,519,521	4,605,084	4,932,233	5,476,142	5,587,863	5,664,875	4,533,017	4,080,275	3,435,432	4,295,511	54,430,437
5	Over/(Under) Recovery (Line 3 - Line 4c)		(547,228)	(1,008,470)	(1,789,742)	(1,697,884)	(1,812,396)	(1,609,566)	(1,917,054)	(1,685,463)	(200,162)	(685,903)	(326,319)	(860,346)	(14,140,532)
6	Interest Provision (Form 42-3A, Line 11)		14,916	9,638	5,794	1,757	(2,000)	(5,173)	(8,655)	(12,196)	(21,114)	(23,821)	(14,256)	(6,996)	(62,106)
7	Adjustments to Period Including Interest		0	0	0	0	0	0	0	0	9,603	0	(9,603)	9,603	9,603
8	Beginning Balance True-Up & Interest Provision		(886,816)	(1,345,227)	(2,270,158)	(3,980,204)	(5,602,430)	(7,342,924)	(8,883,761)	(10,735,569)	(12,359,327)	(12,497,099)	(13,132,921)	(13,409,198)	(886,816)
	a. Deferred True-Up from January 2007 to December 2007 (Order No. PSC-07-0922-FOF-EI)		5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717
9	True-Up Collected/(Refunded) (see Line 2)		73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	886,816
10	End of Period Total True-Up (Lines 5+6+7+8+8a+9)		4,217,490	3,292,560	1,582,512	(39,712)	(1,780,207)	(3,321,045)	(5,172,852)	(6,796,610)	(6,943,985)	(7,570,204)	(7,846,481)	(8,630,318)	(8,630,318)
11	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
12	End of Period Total True-Up (Lines 9 + 10)		$4,217,490	$3,292,560	$1,582,512	($39,712)	($1,780,207)	($3,321,045)	($5,172,852)	($6,796,610)	($6,943,985)	($7,570,204)	($7,846,481)	($8,630,318)	($8,630,318)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

Form 42-3A

Interest Provision
(in Dollars)

Line	Description	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 8 + 8a + 11)	**$4,675,901**	$4,217,490	$3,292,559	$1,582,513	($39,713)	($1,780,207)	($3,321,044)	($5,172,852)	($6,787,007)	($6,934,382)	($7,579,807)	($7,836,878)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5+9)	4,202,574	3,282,921	1,576,719	(41,469)	(1,778,207)	(3,315,871)	(5,164,197)	(6,784,414)	(6,913,268)	(7,546,383)	(7,832,225)	(8,623,323)	
3	Adjustments to Period Including Interest	0	0	0	0	0	0	0	0	(9,816)	0	0	0	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	8,878,475	7,500,412	4,869,279	1,541,044	(1,817,920)	(5,096,079)	(8,485,242)	(11,957,266)	(13,710,090)	(14,480,765)	(15,412,032)	(16,460,201)	
4	Average True-Up Amount (Line 3 x 1/2)	4,439,238	3,750,206	2,434,640	770,522	(908,960)	(2,548,040)	(4,242,621)	(5,978,633)	(6,855,046)	(7,240,383)	(7,706,016)	(8,230,101)	
5	Interest Rate (First Day of Reporting Business Month)	4.98%	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.44%	2.45%	4.95%	2.95%	1.49%	
6	Interest Rate (First Day of Subsequent Business Month)	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.44%	2.45%	4.95%	2.95%	1.49%	0.54%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.06%	6.17%	5.72%	5.47%	5.27%	4.88%	4.89%	4.89%	7.40%	7.90%	4.44%	2.03%	
8	Average Interest Rate (Line 7 x 1/2)	4.030%	3.085%	2.860%	2.735%	2.635%	2.440%	2.445%	2.445%	3.700%	3.950%	2.220%	1.015%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.336%	0.257%	0.238%	0.228%	0.220%	0.203%	0.204%	0.204%	0.308%	0.329%	0.185%	0.085%	
10	Interest Provision for the Month (Line 4 x Line 9)	$14,916	$9,638	$5,794	$1,757	($2,000)	($5,173)	($8,655)	($12,196)	($21,114)	($23,821)	($14,256)	($6,996)	**($62,106)**

PROGRESS ENERGY FLORIDA

Form 42 4A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

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	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$2,581,940	$1,733,861	$848,079	49%
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	3,325,716	3,193,542	132,174	4%
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	19,416,714	15,348,112	4,068,602	27%
3	Pipeline Integrity Management	504,671	483,057	21,614	4%
4	Above Ground Tank Secondary Containment	371,438	368,303	3,135	1%
5	SO2/NOx Emissions Allowances	13,878,857	14,911,514	(1,032,657)	-7%
6	Phase II Cooling Water Intake	124,779	109,372	15,407	14%
7.2	CAIR/CAMR - Peaking - Demand	0	0	0	N/A
8	Arsenic Groundwater Standard - Base	0	0	0	N/A
9	Sea Turtle - Coastal Street Lighting - Distrib	110,572	106,711	3,861	4%
11	Modular Cooling Towers - Base	3,336,752	3,336,752	0	0%
12	Greenhouse Gas Inventory and Reporting - Energy	7,718	7,440	278	4%
13	CAIR A&G	35,605	0	35,605	100%
2	Total O&M Activities - Recoverable Costs	**$43,694,761**	**$39,598,664**	**$4,096,097**	10%
3	Recoverable Costs Allocated to Energy	13,886,574	14,918,954	(1,032,657)	-7%
4	Recoverable Costs Allocated to Demand	29,808,187	24,679,710	5,128,754	21%

Notes:

Column (1) is the End of Period Totals on Form 42-5A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-5A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

O&M Activities
(in Dollars)

Line	Description	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Description of O&M Activities													
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$61,886	$59,344	$394,789	$317,657	$233,421	$311,208	$71,316	$198,538	$228,191	$267,526	$188,420	$249,644	$2,581,940
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	178,491	452,322	121,795	(1,852)	605,200	174,267	463,699	321,024	154,717	179,338	442,958	233,757	3,325,716
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	1,353,452	1,216,372	1,817,242	2,336,394	1,981,067	1,698,585	1,858,800	2,075,110	1,146,712	1,627,938	836,358	1,468,685	19,416,714
3	Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	4,150	91,848	14,562	18,639	30,437	16,110	32,767	18,867	20,184	23,046	6,824	227,239	504,671
4	Above Ground Tank Secondary Containment - Pkg	270	190	367,843	0	0	0	0	0	0	1,520	1,615	0	371,438
5	SO2 Emissions Allowances	1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,505	1,294,040	1,206,366	1,105,790	932,138	844,942	994,835	13,878,857
6	Phase II Cooling Water Intake 316(b) - Base	12,792	0	13,129	12,791	0	347	0	0	0	0	0	0	39,058
6a	Phase II Cooling Water Intake 316(b) - Intm	25,751	0	0	7,896	6,466	202	653	1,227	38,533	(31)	10,050	(5,025)	85,720
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	351	1,420	291	(351)	0	102,000	164	4,266	2,254	178	0	0	110,572
11	Modular Cooling Towers - Base	0	0	0	0	0	834,188	834,188	834,188	834,188	0	0	0	3,336,752
12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	7,718	7,718
13	CAIR	0	0	0	0	0	0	0		0	0	0	35,605	35,605
2	Total of O&M Activities	2,989,682	2,990,672	4,002,039	3,838,377	4,023,522	4,529,411	4,555,627	4,659,585	3,530,568	3,031,654	2,331,167	3,212,458	**$43,694,761**
3	Recoverable Costs Allocated to Energy	1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,505	1,294,040	1,206,366	1,105,790	932,138	844,942	1,002,552	13,886,574
4	Recoverable Costs Allocated to Demand - Transm	61,886	59,344	394,789	317,657	233,421	311,208	71,316	198,538	228,191	267,526	188,420	249,644	2,581,940
	Recoverable Costs Allocated to Demand - Distrib	1,532,294	1,670,114	1,939,328	2,334,190	2,586,268	1,974,852	2,322,563	2,400,399	1,303,683	1,807,454	1,279,316	1,702,442	22,853,002
	Recoverable Costs Allocated to Demand - Prod-Base	12,792	0	13,129	12,791	0	834,535	834,188	834,188	834,188	0	0	0	3,375,810
	Recoverable Costs Allocated to Demand - Prod-Intm	30,171	92,038	14,562	26,534	36,902	16,312	33,420	20,094	58,716	24,535	18,489	222,214	593,987
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	367,843	0	0	0	0	0	0	1,520	1,615	0	370,978
	Recoverable Costs Allocated to Demand - A&G	0	0	0	0	0	0	0	0	0	0	0	35,605	35,605
5	Retail Energy Jurisdictional Factor	0.96490	0.96670	0.96840	0.96830	0.94630	0.95240	0.94850	0.95230	0.95630	0.94960	0.96240	0.96690	
6	Retail Transmission Demand Jurisdictional Factor	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
	Retail Production Demand Jurisdictional Factor - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Production Demand Jurisdictional Factor - Intm	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Production Demand Jurisdictional Factor - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
	Retail Production Demand Jurisdictional Factor - A&G	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	
7	Jurisdictional Energy Recoverable Costs (A)	1,305,066	1,130,243	1,232,181	1,110,838	1,104,267	1,326,222	1,227,397	1,148,823	1,057,467	885,159	813,172	969,368	13,310,203
8	Jurisdictional Demand Recoverable Costs - Transm (B)	43,690	41,895	278,709	224,256	164,788	219,703	50,347	140,162	161,096	188,866	133,019	176,241	1,822,772
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,526,119	1,663,383	1,931,512	2,324,784	2,575,845	1,966,893	2,313,302	2,390,726	1,298,429	1,800,170	1,274,160	1,695,581	22,760,904
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	11,992	0	12,309	11,991	0	782,402	782,076	782,076	782,076	0	0	0	3,164,922
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	23,849	72,752	11,511	20,974	29,170	12,894	26,417	15,883	46,413	19,394	14,615	175,651	469,523
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	327,303	0	0	0	0	0	0	1,352	1,437	0	330,092
	Jurisdictional Demand Recoverable Costs - A&G	0	0	0	0	0	0	0	0	0	0	0	32,639	32,639
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$2,910,716	$2,908,273	$3,793,525	$3,692,843	$3,874,070	$4,308,114	$4,399,539	$4,477,670	$3,345,481	$2,894,941	$2,236,403	$3,049,480	$41,891,055

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 2008 through December 2008

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				
	3.1 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$516,906	$521,581	($4,675)	-1%
	4.x Above Ground Tank Secondary Containment	781,112	798,905	(17,793)	-2%
	5 SO2/NOx Emissions Allowances	9,664,191	9,616,405	47,786	0%
	7.x CAIR/CAMR	2,106,508	2,094,513	11,995	1%
	9 Sea Turtle - Coastal Street Lighting -Distribution	1,586	2,398	(812)	-34%
	10.x Underground Storage Tanks-Base	41,499	41,499	0	0%
	11 Modular Cooling Towers - Base	192,713	192,713	0	0%
2	Total Capital Investment Activities - Recoverable Costs	**13,304,515**	**13,268,014**	**$36,501**	0%
3	Recoverable Costs Allocated to Energy	9,664,191	9,616,405	$47,786	0%
4	Recoverable Costs Allocated to Demand	$3,640,324	$3,651,609	($11,285)	0%

Notes:
Column (1) is the End of Period Totals on Form 42-7A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

PROGRESS ENERGY FLORIDA

Form 42-7A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$35,507	$35,432	$35,356	$35,521	$88,845	$37,302	$37,680	$39,038	$40,513	$41,555	$42,815	$47,342	$516,906
4.1	Above Ground Tank Secondary Containment - Peaking	62,325	63,919	(128,152)	61,942	64,222	68,957	72,297	74,940	79,678	84,115	86,827	91,488	682,558
4.2	Above Ground Tank Secondary Containment - Base	440	438	437	436	434	433	432	431	430	8,850	17,275	22,990	53,026
4.3	Above Ground Tank Secondary Containment - Intermediate	5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528
5	SO2/NOX Emissions Allowances - Energy	513,506	745,789	787,863	805,444	828,812	861,783	883,746	870,189	857,554	846,391	836,616	826,498	9,664,191
7.1	CAIR/CAMR Anclote- Intermediate	706	706	706	706	706	706	706	706	706	706	706	354	8,120
7.2	CAIR CT's - Peaking	27,094	28,453	28,497	28,502	13,374	26,129	26,094	25,942	25,903	25,859	25,820	25,780	307,447
7.3	CAMR Crystal River - Base	410	590	866	1,031	1,240	1,502	1,615	1,918	2,231	2,246	2,686	3,144	19,479
7.4	CAIR/CAMR Crystal River AFUDC - Base	0	0	0	0	118,130	223,170	225,998	228,046	231,693	233,432	234,190	276,803	1,771,462
9	Sea Turtle - Coastal Street Lighting -Distribution	106	106	106	109	110	110	156	156	157	157	157	156	1,586
10.1	Underground Storage Tanks-Base	2,434	2,429	2,424	2,418	2,414	2,409	2,404	2,398	2,393	2,389	2,383	2,378	28,873
10.2	Underground Storage Tanks-Intermediate	1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,046	1,044	1,043	1,040	12,626
11	Modular Cooling Towers - Base	15,981	15,860	15,738	15,616	15,493	15,371	20,490	15,876	15,755	15,633	15,511	15,389	192,713
2	Total Investment Projects - Recoverable Costs	664,674	899,867	749,966	957,830	1,139,864	1,243,936	1,267,548	1,264,769	1,262,131	1,266,440	1,270,083	1,317,407	**13,304,515**
3	Recoverable Costs Allocated to Energy	513,506	745,789	787,863	805,444	828,812	861,783	883,746	870,189	857,554	846,391	836,616	826,498	9,664,191
	Recoverable Costs Allocated to Demand	106	106	106	109	110	110	156	156	157	157	157	156	1,586
4	Recoverable Costs Allocated to Demand - Production - Base	19,265	19,317	19,465	19,501	137,711	242,885	250,939	248,669	252,502	262,550	272,045	320,704	2,065,553
	Recoverable Costs Allocated to Demand - Production - Intermediate	42,378	42,283	42,187	42,332	95,635	44,072	34,316	44,873	46,337	47,368	48,618	52,781	583,180
	Recoverable Costs Allocated to Demand - Production - Peaking	89,419	92,372	(99,655)	90,444	77,596	95,086	98,391	100,882	105,581	109,974	112,647	117,268	990,005
5	Retail Energy Jurisdictional Factor	0.96490	0.96670	0.96840	0.96830	0.94630	0.95240	0.94850	0.95230	0.95630	0.94960	0.96240	0.96690	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
6	Retail Demand Jurisdictional Factor - Production - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
7	Jurisdictional Energy Recoverable Costs (B)	495,482	720,954	762,967	779,911	784,305	820,762	838,233	828,681	820,079	803,733	805,159	799,141	9,259,407
	Jurisdictional Demand Recoverable Costs (B)	106	106	106	109	110	110	155	155	156	156	156	155	1,580
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	18,062	18,110	18,249	18,283	129,108	227,712	235,263	233,135	236,728	246,149	255,050	300,670	1,936,518
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	33,498	33,423	33,347	33,462	75,596	34,837	27,125	35,470	36,628	37,443	38,431	41,721	460,980
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	79,564	82,192	(88,672)	80,476	69,044	84,607	87,547	89,764	93,945	97,854	100,232	104,344	880,897
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$626,711	$854,785	$725,996	$912,241	$1,058,162	$1,168,027	$1,188,324	$1,187,205	$1,187,536	$1,185,334	$1,199,029	$1,246,031	$12,539,382

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

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$43,664	$0	$28,993	$57,985	$207,093	$79,338	$128,313	$119,218	$296,008	**$960,613**
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	983,298	
	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		**$2,674,588**	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	3,657,886	
3	Less: Accumulated Depreciation		**(254,167)**	(261,009)	(267,852)	(274,694)	(281,537)	(354,101)	(363,210)	(372,319)	(381,428)	(390,537)	(399,646)	(408,755)	(419,544)	
4	CWIP - Non-Interest Bearing		**22,685**	22,685	22,685	22,685	66,349	66,349	95,342	153,327	360,420	439,758	568,072	687,290	0	
5	Net Investment (Lines 2 + 3 + 4)		**$2,443,106**	2,436,264	2,429,421	2,422,579	2,459,401	2,386,837	2,406,721	2,455,597	2,653,580	2,723,810	2,843,014	2,953,123	3,238,343	
6	Average Net Investment			2,439,685	2,432,843	2,426,000	2,440,990	2,423,122	2,396,779	2,431,158	2,554,588	2,688,695	2,783,412	2,898,068	3,095,733	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		22,689	22,625	22,562	22,701	22,535	22,291	22,610	23,758	25,005	25,885	26,952	28,790	$288,403
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		4,147	4,136	4,124	4,150	4,119	4,074	4,133	4,343	4,571	4,733	4,926	5,263	52,719
	c. Other (C)			0	0	0	0	(12,208)	0	0	0	0	0	0	0	(12,208)
8	Investment Expenses															
	a. Depreciation (D)			6,842	6,842	6,842	6,842	9,109	9,109	9,109	9,109	9,109	9,109	9,109	10,789	101,920
	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 (E)			1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	2,500	22,608
	e. Other			0	0	0	0	63,462	0	0	0	0	0	0	0	63,462
9	Total System Recoverable Expenses (Lines 7 + 8)			35,507	35,432	35,356	35,521	88,845	37,302	37,680	39,038	40,513	41,555	42,815	47,342	516,906
	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			35,507	35,432	35,356	35,521	88,845	37,302	37,680	39,038	40,513	41,555	42,815	47,342	516,906
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)			0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)			28,067	28,008	27,948	28,078	70,228	29,486	29,785	30,858	32,024	32,848	33,844	37,422	408,596
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$28,067	$28,008	$27,948	$28,078	$70,228	$29,486	$29,785	$30,858	$32,024	$32,848	$33,844	$37,422	$408,596

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) The credit in May is due to the true-up of depreciation rates which affected the return on average net investment for 2008.
(D) 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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(E) Lines 2 x 89% @ .008313 x 1/12 + 11%@ .007299 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			($65,198)	$304,187	$44,654	$39,638	$396,364	$486,094	$135,334	$352,941	$241,037	$438,887	$91,224	$672,140	**$3,137,300**
	b. Clearings to Plant			363,266	(2,767)	(2)	0	0	0	428	13,519	1,042,889	10,428	(28,240)	343,275	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	(367,843)	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		**$3,525,178**	3,888,444	3,885,677	3,885,675	3,885,675	3,885,675	3,885,675	3,886,102	3,899,621	4,942,510	4,952,938	4,924,698	5,267,973	
3	Less: Accumulated Depreciation		**(141,321)**	(151,700)	(162,478)	(180,096)	(190,874)	(201,652)	(212,430)	(216,369)	(227,178)	(238,803)	(251,251)	(263,654)	(276,408)	
4	CWIP - Non-Interest Bearing		1,131,378	702,913	1,009,867	686,680	726,319	1,122,683	1,608,776	1,743,682	2,083,104	1,281,252	1,709,712	1,829,175	2,158,040	
5	Net Investment (Lines 2 + 3 + 4)		**$4,515,235**	4,439,657	4,733,066	4,392,259	4,421,119	4,806,705	5,282,021	5,413,415	5,755,547	5,984,960	6,411,399	6,490,220	7,149,605	
6	Average Net Investment			4,477,446	4,586,361	4,378,741	4,406,689	4,613,912	5,044,363	5,347,717	5,584,480	5,870,253	6,198,178	6,450,808	6,819,912	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		41,640	42,653	40,721	40,983	42,909	46,913	49,735	51,937	54,593	57,642	59,993	63,425	$593,144
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		7,613	7,797	7,443	7,490	7,844	8,575	9,092	9,494	9,980	10,537	10,964	11,594	108,423
	c. Other (A)			0	0	(189,785)	0	0	0	0	0	0	0	0	0	(189,785)
8	Investment Expenses															
	a. Depreciation (C)			10,379	10,778	10,778	10,778	10,778	10,778	10,779	10,809	11,625	12,448	12,403	12,754	135,087
	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)			2,693	2,691	2,691	2,691	2,691	2,691	2,691	2,700	3,480	3,488	3,467	3,715	35,689
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			62,325	63,919	(128,152)	61,942	64,222	68,957	72,297	74,940	79,678	84,115	86,827	91,488	682,557
	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			62,325	63,919	(128,152)	61,942	64,222	68,957	72,297	74,940	79,678	84,115	86,827	91,488	682,557
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)			0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)			55,456	56,874	(114,028)	55,115	57,144	61,357	64,329	66,681	70,897	74,845	77,258	81,405	607,333
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$55,456	$56,874	($114,028)	$55,115	$57,144	$61,357	$64,329	$66,681	$70,897	$74,845	$77,258	$81,405	$607,333

Notes:
(A) Credit in March due to impairment of portion of original work for tank at Turner plant that subsequently failed (Project 4.1a on Capital Program Detail file). The failed technology used was approved by the DEP at that time. This expense is recovered on Line 4 of 42-5A, and the return on investment portion is captured within the amount on Line 15 of 42-7A.
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-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 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,531,216	$757	$336,869	$1,868,842
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	1,868,841	
	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		$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	1,901,933	
3	Less: Accumulated Depreciation		(5,883)	(5,994)	(6,105)	(6,216)	(6,327)	(6,438)	(6,549)	(6,660)	(6,771)	(6,882)	(6,993)	(7,104)	(9,419)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	1,531,216	1,531,973	0	
5	Net Investment (Lines 2+ 3 + 4)		$27,208	27,098	26,987	26,876	26,765	26,654	26,543	26,432	26,321	26,210	1,557,315	1,557,961	1,892,515	
6	Average Net Investment			27,153	27,042	26,931	26,820	26,709	26,598	26,487	26,376	26,265	791,762	1,557,637	1,725,237	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		253	251	250	249	248	247	246	245	244	7,363	14,486	16,045	40,127
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		46	46	46	46	45	45	45	45	45	1,346	2,648	2,933	7,336
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			111	111	111	111	111	111	111	111	111	111	111	2,315	3,536
	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)			30	30	30	30	30	30	30	30	30	30	30	1,697	2,027
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			440	438	437	436	434	433	432	431	430	8,850	17,275	22,990	53,026
	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			440	438	437	436	434	433	432	431	430	8,850	17,275	22,990	53,026
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			413	411	410	409	407	406	405	404	403	8,297	16,196	21,554	49,713
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$413	$411	$410	$409	$407	$406	$405	$404	$403	$8,297	$16,196	$21,554	$49,713

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-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 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	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	(5,509)	(7,240)	(8,871)	(10,502)	(12,133)	(13,764)	(15,395)	(8,482)	(9,290)	(10,098)	(10,906)	(11,714)	(12,522)	
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)	$284,689	283,058	281,427	279,796	278,165	276,534	274,903	281,816	281,008	280,200	279,392	278,584	277,776	
6	Average Net Investment		283,873	282,242	280,611	278,980	277,349	275,718	278,359	281,412	280,604	279,796	278,988	278,180	0
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		2,640	2,625	2,610	2,595	2,579	2,564	2,589	2,617	2,610	2,602	2,595	2,587	31,213
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		483	480	477	474	471	469	473	478	477	476	474	473	5,705
	c. Other		0	0	0	0	0	0	214	0	0	0	0	0	214
8	Investment Expenses														
	a. Depreciation (C)		1,631	1,631	1,631	1,631	1,631	1,631	808	808	808	808	808	808	14,634
	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)		347	347	347	347	347	347	177	177	177	177	177	177	3,144
	e. Other		0	0	0	0	0	0	(9,382)	0	0	0	0	0	(9,382)
9	Total System Recoverable Expenses (Lines 7 + 8)		5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528
	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		5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		4,032	4,018	4,004	3,989	3,974	3,961	(4,048)	3,225	3,219	3,212	3,205	3,197	35,988
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,032	$4,018	$4,004	$3,989	$3,974	$3,961	($4,048)	$3,225	$3,219	$3,212	$3,205	$3,197	$35,988

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-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 2007 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 2008 through December 2008

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		**$2,905,441**	$24,564,484	$23,379,390	$22,091,084	$20,927,963	$19,465,163	$18,000,751	$16,634,804	$15,356,530	$14,178,833	$13,174,788	$12,257,938	$11,191,196	$11,191,196
	b. 25401FL Auctioned SO_2 Allowance		**(2,019,940)**	(2,004,023)	(1,988,106)	(1,972,189)	(1,956,272)	(2,566,605)	(2,494,697)	(2,422,790)	(2,350,883)	(2,278,975)	(2,207,068)	(2,135,161)	(2,063,254)	(2,063,254)
	c. 1581002 NOX Emission Allowance Inventory		**28,663,433**	41,255,433	50,390,808	51,346,838	56,006,838	58,816,088	65,467,108	65,495,858	65,502,545	65,510,820	65,510,820	65,510,820	65,510,820	65,510,820
	d. 1581003 Nox Emissions Allowance Reserve		**0**	0	0	0	0	0	0	0	0	0	0	0	0	
2	Total Working Capital		**$29,548,933**	63,815,893	71,782,092	71,465,733	74,978,528	75,714,646	80,973,162	79,707,871	78,508,192	77,410,678	76,478,539	75,633,597	74,638,763	74,638,763
3	Average Net Investment			46,682,413	67,798,992	71,623,912	73,222,131	75,346,587	78,343,904	80,340,516	79,108,032	77,959,435	76,944,609	76,056,068	75,136,180	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		434,146	630,531	666,102	680,966	700,723	728,598	747,167	735,705	725,023	715,585	707,321	698,766	$8,170,633
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		79,360	115,258	121,761	124,478	128,089	133,185	136,579	134,484	132,531	130,806	129,295	127,732	1,493,558
5	Total Return Component (B)			513,506	745,789	787,863	805,444	828,812	861,783	883,746	870,189	857,554	846,391	836,616	826,498	9,664,191
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			1,368,457	1,185,094	1,288,306	1,163,121	1,462,800	1,464,412	1,365,948	1,278,274	1,177,697	1,004,046	916,849	1,066,742	14,741,745
	b. 4074004 Amortization Expense			($15,917)	($15,917)	($15,917)	($15,917)	($295,869)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($862,888)
	c. 5090003 Nox Allowance Expense			$0	$0	$0	$0	$0	$0	$0	$0	0	$0	$0	$0	
7	Net Expense (C)			1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,505	1,294,040	1,206,366	1,105,790	932,138	844,942	994,835	13,878,857
8	Total System Recoverable Expenses (Lines 5 + 7)			1,866,046	1,914,966	2,060,252	1,952,648	1,995,743	2,254,288	2,177,786	2,076,555	1,963,344	1,778,529	1,681,558	1,821,333	23,543,048
	a. Recoverable costs allocated to Energy			1,866,046	1,914,966	2,060,252	1,952,648	1,995,743	2,254,288	2,177,786	2,076,555	1,963,344	1,778,529	1,681,558	1,821,333	23,543,048
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96490	0.96670	0.96840	0.96830	0.94630	0.95240	0.94850	0.95230	0.95630	0.94960	0.96240	0.96690	
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)			1,800,548	1,851,197	1,995,148	1,890,749	1,888,572	2,146,984	2,065,630	1,977,504	1,877,546	1,688,891	1,618,331	1,761,046	22,562,147
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)			$ 1,800,548	$ 1,851,197	$ 1,995,148	$ 1,890,749	$ 1,888,572	$ 2,146,984	$ 2,065,630	$ 1,977,504	$ 1,877,546	$ 1,688,891	$ 1,618,331	$ 1,761,046	$ 22,562,147

Notes:
(A) Lines 3 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 Rate Case Settlement in Dkt. 050078-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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$7	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($64,200)	**($64,193)**
	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	**64,192**	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	(1)	
5	Net Investment (Lines 2 + 3 + 4)	**$64,192**	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	(1)	
6	Average Net Investment		64,195	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	32,098	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) **11.16%**		597	597	597	597	597	597	597	597	597	597	597	299	$6,866
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		109	109	109	109	109	109	109	109	109	109	109	55	1,254
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) **2.21%**		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) **0.007299**		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)		706	706	706	706	706	706	706	706	706	706	706	354	8,120
	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	706	706	706	706	706	706	706	706	706	706	354	8,120
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		558	558	558	558	558	558	558	558	558	558	558	280	6,419
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$280	$6,419

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$23,317	$11,748	$5,189	$4,727	$20,457	$26,428	($20,026)	$0	$0	$0	$0	$0	**$71,841**
	b. Clearings to Plant			705,515	11,748	5,189	4,727	20,457	26,428	(20,026)	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		**$1,180,361**	1,885,876	1,897,624	1,902,813	1,907,540	1,927,997	1,954,426	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	
3	Less: Accumulated Depreciation		**(5,914)**	(11,174)	(17,656)	(24,156)	(30,672)	(21,562)	(25,234)	(28,889)	(32,544)	(36,199)	(39,854)	(43,509)	(47,164)	
4	CWIP - Non-Interest Bearing		**682,200**	2	2	2	2	1	1	1	1	1	1	1	1	
5	Net Investment (Lines 2 + 3 + 4)		**$1,856,647**	1,874,704	1,879,970	1,878,659	1,876,870	1,906,437	1,929,193	1,905,513	1,901,858	1,898,203	1,894,548	1,890,893	1,887,238	
6	Average Net Investment			1,865,675	1,877,337	1,879,314	1,877,765	1,891,653	1,917,816	1,917,354	1,903,686	1,900,031	1,896,376	1,892,721	1,889,066	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,351	17,460	17,477	17,465	17,874	17,837	17,832	17,704	17,671	17,635	17,601	17,569	$211,476
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,172	3,191	3,195	3,193	3,268	3,260	3,261	3,237	3,231	3,223	3,218	3,210	38,659
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			5,260	6,482	6,500	6,516	(9,110)	3,672	3,655	3,655	3,655	3,655	3,655	3,655	41,250
	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)			1,311	1,320	1,325	1,328	1,342	1,360	1,346	1,346	1,346	1,346	1,346	1,346	16,062
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			27,094	28,453	28,497	28,502	13,374	26,129	26,094	25,942	25,903	25,859	25,820	25,780	307,447
	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			27,094	28,453	28,497	28,502	13,374	26,129	26,094	25,942	25,903	25,859	25,820	25,780	307,447
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)			0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)			24,108	25,317	25,356	25,361	11,900	23,249	23,218	23,083	23,048	23,009	22,974	22,939	273,563
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$24,108	$25,317	$25,356	$25,361	$11,900	$23,249	$23,218	$23,083	$23,048	$23,009	$22,974	$22,939	$273,563

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-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 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$2,974	$29,737	$20,357	$9,793	$28,042	$19,736	$748	$54,383	$2,466	$373	$79,537	$3,610	**$251,755**
	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		**35,814**	38,788	68,525	88,881	98,675	126,717	146,453	147,201	201,584	204,050	204,422	283,959	287,569	
5	Net Investment (Lines 2 + 3 + 4)		**$35,814**	38,788	68,525	88,881	98,675	126,717	146,453	147,201	201,584	204,050	204,422	283,959	287,569	
6	Average Net Investment			37,301	53,656	78,703	93,778	112,696	136,585	146,827	174,393	202,817	204,236	244,191	285,764	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		347	499	732	872	1,048	1,270	1,365	1,622	1,886	1,899	2,271	2,658	$16,469
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		63	91	134	159	192	232	250	296	345	347	415	486	3,010
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.19%		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)	0.010707		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)			410	590	866	1,031	1,240	1,502	1,615	1,918	2,231	2,246	2,686	3,144	19,479
	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			410	590	866	1,031	1,240	1,502	1,615	1,918	2,231	2,246	2,686	3,144	19,479
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			384	553	812	967	1,163	1,408	1,514	1,798	2,092	2,106	2,518	2,948	18,262
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$384	$553	$812	$967	$1,163	$1,408	$1,514	$1,798	$2,092	$2,106	$2,518	$2,948	$18,262

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$56,759,253	$53,940,373	$45,795,073	$49,541,474	$51,758,776	$44,201,549	$40,741,834	$38,425,935	$41,038,265	$33,863,625	$35,647,223	$32,345,629	**$524,059,008**
	b. Clearings to Plant			0	0	0	0	15,150,677	101,267	298,338	67,809	408,520	(665)	136,729	5,599,409	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)	8.848%		2,091,783	2,591,334	3,263,937	3,348,228	3,707,018	3,977,574	4,313,612	4,703,698	4,964,269	836,365	4,820,548	5,095,418	43,713,783
2	Plant-in-Service/Depreciation Base		**$0**	0	0	0	0	15,150,677	15,251,944	15,550,281	15,618,090	16,026,610	16,025,945	16,162,674	21,762,083	
3	Less: Accumulated Depreciation		**0**	0	0	0	0	(21,401)	(64,488)	(108,418)	(152,539)	(197,814)	(243,087)	(288,747)	(341,009)	
4	CWIP - AFUDC-Interest Bearing		**328,850,158**	387,701,194	444,232,901	493,291,911	546,181,614	586,496,730	634,574,587	679,331,694	722,393,518	767,967,532	802,688,187	843,019,229	874,860,866	567,772,791
5	Net Investment (Lines 2 + 3 + 4)		**$328,850,158**	387,701,194	444,232,901	493,291,911	546,181,614	601,626,007	649,762,043	694,773,558	737,859,070	783,816,328	818,471,046	858,893,156	896,281,941	
6	Average Net Investment			358,275,676	415,967,047	468,762,406	519,736,762	573,903,810	625,694,025	672,267,800	716,316,314	760,837,699	801,143,687	838,682,101	877,587,548	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	0	70,351	140,747	142,200	143,719	145,519	146,991	147,201	173,422	1,110,150
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	12,860	25,728	25,994	26,271	26,600	26,869	26,908	31,701	202,931
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	21,401	43,087	43,930	44,121	45,275	45,273	45,660	52,263	334,407
	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	13,518	13,608	13,874	13,935	14,299	14,299	14,421	19,417	117,371
	e. Property Insurance							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	118,130	223,170	225,998	228,046	231,693	233,432	234,190	276,803	1,771,462
	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	118,130	223,170	225,998	228,046	231,693	233,432	234,190	276,803	1,771,462
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
12	Retail Energy-Related Recoverable Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs			0	0	0	0	110,750	209,229	211,880	213,800	217,219	218,850	219,560	259,511	1,660,799
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$110,750	$209,229	$211,880	$213,800	$217,219	$218,850	$219,560	$259,511	$1,660,799

Notes:
(A) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(B) Return on equity and debt calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 6 x rate x 1/12. Rate based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Depreciation calculated only on assets placed inservice which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property taxes calculated only on assets placed inervice which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2007 Effective Tax Rate on original cost.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$351	$0	$0	$0	$0	$95	$0	$0	$0	**$446**
	b. Clearings to Plant		0	0	0	0	0	0	10,051	0	95	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	10,051	10,051	10,146	10,146	10,146	10,146	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	(38)	(76)	(115)	(154)	(193)	(232)	
4	CWIP - Non-Interest Bearing	**9,700**	9,700	9,700	9,700	10,051	10,051	10,051	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	**$9,700**	9,700	9,700	9,700	10,051	10,051	10,051	10,013	9,975	10,031	9,992	9,953	9,914	
6	Average Net Investment		9,700	9,700	9,700	9,876	10,051	10,051	10,032	9,994	10,003	10,012	9,973	9,934	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		90	90	90	92	93	93	93	93	93	93	93	92	$1,105
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		16	16	16	17	17	17	17	17	17	17	17	17	201
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 4.59%		0	0	0	0	0	0	38	38	39	39	39	39	232
	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) 0.009400		0	0	0	0	0	0	8	8	8	8	8	8	48
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		106	106	106	109	110	110	156	156	157	157	157	156	1,586
	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	106	106	109	110	110	156	156	157	157	157	156	1,586
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)		0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
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)		106	106	106	109	110	110	155	155	156	156	156	155	1,580
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$106	$106	$106	$109	$110	$110	$155	$155	$156	$156	$156	$155	$1,580

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	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		(2,992)	(3,452)	(3,912)	(4,372)	(4,832)	(5,292)	(5,752)	(6,212)	(6,672)	(7,132)	(7,592)	(8,052)	(8,512)	
	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)		$165,949	165,489	165,029	164,569	164,109	163,649	163,189	162,729	162,269	161,809	161,349	160,889	160,429	
	6 Average Net Investment			165,719	165,259	164,799	164,339	163,879	163,419	162,959	162,499	162,039	161,579	161,119	160,659	
	7 Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		1,541	1,537	1,533	1,528	1,524	1,520	1,516	1,511	1,507	1,503	1,498	1,494	$18,212
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		282	281	280	279	279	278	277	276	275	275	274	273	3,329
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	8 Investment Expenses															
	a. Depreciation (C)	3.27%		460	460	460	460	460	460	460	460	460	460	460	460	5,520
	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)	0.010707		151	151	151	151	151	151	151	151	151	151	151	151	1,812
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Total System Recoverable Expenses (Lines 7 + 8)			2,434	2,429	2,424	2,418	2,414	2,409	2,404	2,398	2,393	2,389	2,383	2,378	28,873
	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			2,434	2,429	2,424	2,418	2,414	2,409	2,404	2,398	2,393	2,389	2,383	2,378	28,873
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			2,282	2,277	2,273	2,267	2,263	2,259	2,254	2,248	2,244	2,240	2,234	2,229	27,069
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,282	$2,277	$2,273	$2,267	$2,263	$2,259	$2,254	$2,248	$2,244	$2,240	$2,234	$2,229	$27,069

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	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	(2,321)	(2,523)	(2,725)	(2,927)	(3,129)	(3,331)	(3,533)	(3,735)	(3,937)	(4,139)	(4,341)	(4,543)	(4,745)	
	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)	$73,685	73,483	73,281	73,079	72,877	72,675	72,473	72,271	72,069	71,867	71,665	71,463	71,261	
	6 Average Net Investment		73,584	73,382	73,180	72,978	72,776	72,574	72,372	72,170	71,968	71,766	71,564	71,362	
	7 Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) **11.16%**		684	682	681	679	677	675	673	671	669	667	666	664	$8,088
	b. Debt Component (Line 6 x 2.04% x 1/12) **2.04%**		125	125	124	124	124	123	123	123	122	122	122	121	1,478
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	8 Investment Expenses														
	a. Depreciation (C) **3.19%**		202	202	202	202	202	202	202	202	202	202	202	202	2,424
	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) **0.008313**		53	53	53	53	53	53	53	53	53	53	53	53	636
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Total System Recoverable Expenses (Lines 7 + 8)		1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,046	1,044	1,043	1,040	12,626
	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		1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,046	1,044	1,043	1,040	12,626
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		841	839	838	836	835	832	831	829	827	825	824	822	9,980
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$841	$839	$838	$836	$835	$832	$831	$829	$827	$825	$824	$822	$9,980

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2007 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 2008 through December 2008

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 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4
	b. Clearings to Plant			0	4	0	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		$665,137	665,137	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		(191,115)	(202,201)	(213,287)	(224,373)	(235,459)	(246,545)	(257,631)	(268,717)	(279,803)	(290,889)	(301,975)	(313,061)	(324,147)	
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)		$474,021	462,935	451,853	440,767	429,681	418,595	407,509	396,423	385,337	374,251	363,165	352,079	340,993	
6	Average Net Investment			468,478	457,394	446,310	435,224	424,138	413,052	401,966	390,880	379,794	368,708	357,622	346,536	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		4,357	4,254	4,151	4,048	3,944	3,841	3,738	3,635	3,532	3,429	3,326	3,223	$45,478
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		796	778	759	740	721	702	683	664	646	627	608	589	8,313
	c. Other (G)			(662)	(662)	(662)	(662)	(662)	(662)	3,972	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	11,086	11,086	11,086	11,086	11,086	11,086	133,032
	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)	0.010707		593	593	593	593	593	593	593	593	593	593	593	593	7,116
	e. Other (G)			(189)	(189)	(189)	(189)	(189)	(189)	418	(102)	(102)	(102)	(102)	(102)	(1,225)
9	Total System Recoverable Expenses (Lines 7 + 8)			15,981	15,860	15,738	15,616	15,493	15,371	20,490	15,876	15,755	15,633	15,511	15,389	192,713
	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			15,981	15,860	15,738	15,616	15,493	15,371	20,490	15,876	15,755	15,633	15,511	15,389	192,713
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			14,983	14,869	14,755	14,640	14,525	14,411	19,210	14,884	14,771	14,656	14,542	14,428	180,674
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$14,983	$14,869	$14,755	$14,640	$14,525	$14,411	$19,210	$14,884	$14,771	$14,656	$14,542	$14,428	$180,674

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Beginning in July, this schedule only includes a credit for depreciation expense that is included in base rates for breakers that were replaced by upgraded breakers to compensate for increased load due to the Modular Cooling Towers. It was determined that only a credit for depreciation expense is required per Order No. PSC-99-2513-FOF-EI so the return and property tax credits for January to June 2008 were reversed in July.

EXHIBIT 2 (WG-2)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2008 - DECEMBER 2008

DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 21
COMPANY Progress Energy Florida, Inc.
WITNESS Will Garrett (WG-2)
DATE 11/02/09

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(In Dollars)

Intermediate

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	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		(3,409)	(3,496)	(3,583)	(3,670)	(3,757)	(3,844)	(3,931)	(4,018)	(4,105)	(4,192)	(4,279)	(4,366)	(4,453)	
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)		$30,544	30,457	30,370	30,283	30,196	30,109	30,022	29,935	29,848	29,761	29,674	29,587	29,500	
6	Average Net Investment			30,500	30,413	30,326	30,239	30,152	30,065	29,978	29,891	29,804	29,717	29,630	29,543	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		284	283	282	281	280	280	279	278	277	276	276	275	$3,351
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		52	52	52	51	51	51	51	51	51	51	50	50	613
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.07%		87	87	87	87	87	87	87	87	87	87	87	87	1,044
	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	0.008201		23	23	23	23	23	23	23	23	23	23	23	23	276
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			446	445	444	442	441	441	440	439	438	437	436	435	5,284
	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			446	445	444	442	441	441	440	439	438	437	436	435	5,284

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(In Dollars)

Intermediate

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	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		(250,749)	(257,505)	(264,261)	(271,017)	(277,773)	(350,257)	(359,279)	(368,301)	(377,323)	(386,345)	(395,367)	(404,389)	(413,411)	
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)		$2,389,887	2,383,131	2,376,375	2,369,619	2,362,863	2,290,379	2,281,357	2,272,335	2,263,313	2,254,291	2,245,269	2,236,247	2,227,225	
6	Average Net Investment			2,386,509	2,379,753	2,372,997	2,366,241	2,326,621	2,285,868	2,276,846	2,267,824	2,258,802	2,249,780	2,240,758	2,231,736	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		22,193	22,130	22,067	22,005	21,638	21,259	21,175	21,091	21,007	20,923	20,839	20,755	$257,082
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		4,057	4,046	4,034	4,023	3,955	3,886	3,871	3,855	3,840	3,825	3,809	3,794	46,995
	c. Other			0	0	0	0	(12,208)	0	0	0	0	0	0	0	(12,208)
8	Investment Expenses															
	a. Depreciation	4.10%		6,756	6,756	6,756	6,756	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	99,200
	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	0.008201		1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	21,660
	e. Other			0	0	0	0	63,462	0	0	0	0	0	0	0	63,462
9	Total System Recoverable Expenses (Lines 7 + 8)			34,811	34,737	34,662	34,589	87,674	35,972	35,873	35,773	35,674	35,575	35,475	35,376	476,191
	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			34,811	34,737	34,662	34,589	87,674	35,972	35,873	35,773	35,674	35,575	35,475	35,376	476,191

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$43,664	$0	$28,993	$57,985	$207,093	$79,338	$128,313	$119,218	$296,008	$960,613
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	983,298	
	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	983,298	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(1,680)	
4	CWIP - Non-Interest Bearing	22,685	22,685	22,685	22,685	66,349	66,349	95,342	153,327	360,420	439,758	568,071	687,290	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$22,685	22,685	22,685	22,685	66,349	66,349	95,342	153,327	360,420	439,758	568,071	687,290	981,618	
6	Average Net Investment		22,685	22,685	22,685	44,517	66,349	80,846	124,334	256,873	400,089	503,915	627,680	834,454	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	211	211	211	414	617	752	1,156	2,389	3,721	4,686	5,837	7,760	$27,965
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%	39	39	39	76	113	137	211	437	680	857	1,067	1,419	5,114
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	4.10%	0	0	0	0	0	0	0	0	0	0	0	1,680	1,680
	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	0.008201	0	0	0	0	0	0	0	0	0	0	0	672	672
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		250	250	250	490	730	889	1,367	2,826	4,401	5,543	6,904	11,531	35,431
	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		250	250	250	490	730	889	1,367	2,826	4,401	5,543	6,904	11,531	35,431

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$303,297	$35,483	$29,422	$41,640	$200,238	$428	$1,849	$122,650	$114,275	$2,018	$390,502	$1,241,800
	b. Clearings to Plant			0	0	0	0	0	0	0	0	1,039,281	10,428	(28,525)	30,000	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	(367,843)	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	1,039,281	1,049,708	1,021,183	1,051,183	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	(808)	(2,439)	(4,025)	(5,658)	
4	CWIP - Non-Interest Bearing		674,010	674,010	977,307	644,946	674,368	716,008	916,246	916,673	918,522	1,891	105,739	136,282	496,784	
5	Net Investment (Lines 2 + 3 + 4)		$674,010	674,010	977,307	644,946	674,368	716,008	916,246	916,673	918,522	1,040,364	1,153,009	1,153,440	1,542,310	
6	Average Net Investment			674,010	825,658	627,205	659,657	695,188	816,127	916,459	917,597	979,443	1,096,686	1,153,224	1,347,875	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		6,268	7,679	5,833	6,135	6,465	7,590	8,523	8,534	9,109	10,199	10,725	12,535	$99,595
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,146	1,404	1,066	1,121	1,182	1,387	1,558	1,560	1,665	1,864	1,960	2,291	18,204
	c. Other			0	0	(189,785)	0	0	0	0	0	0	0	0	0	(189,785)
8	Investment Expenses															
	a. Depreciation	1.86%		0	0	0	0	0	0	0	0	808	1,631	1,586	1,633	5,858
	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	0.008974		0	0	0	0	0	0	0	0	777	785	764	786	3,112
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			7,414	9,083	(182,886)	7,256	7,647	8,977	10,081	10,094	12,359	14,479	15,035	17,245	(63,217)
	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			7,414	9,083	(182,886)	7,256	7,647	8,977	10,081	10,094	12,359	14,479	15,035	17,245	(63,217)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,060	$3,283	$9,227	$15,570
	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		$153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	
3	Less: Accumulated Depreciation		(25,508)	(25,932)	(26,356)	(26,780)	(27,204)	(27,628)	(28,052)	(28,476)	(28,900)	(29,324)	(29,748)	(30,172)	(30,596)	
4	CWIP - Non-Interest Bearing		1,755	1,755	1,755	1,755	1,755	1,756	1,755	1,755	1,755	1,755	4,815	8,098	17,325	
5	Net Investment (Lines 2 + 3 + 4)		$129,945	129,521	129,097	128,673	128,249	127,825	127,401	126,977	126,553	126,129	128,765	131,624	140,427	
6	Average Net Investment			129,733	129,309	128,885	128,461	128,037	127,613	127,189	126,765	126,341	127,447	130,195	136,026	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,207	1,203	1,199	1,195	1,191	1,187	1,183	1,179	1,175	1,185	1,211	1,265	$14,380
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		221	220	219	218	218	217	216	216	215	217	221	231	2,629
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.31%		424	424	424	424	424	424	424	424	424	424	424	424	5,088
	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	0.008313		106	106	106	106	106	106	106	106	106	106	106	106	1,272
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,958	1,953	1,948	1,943	1,939	1,934	1,929	1,925	1,920	1,932	1,962	2,026	23,369
	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			1,958	1,953	1,948	1,943	1,939	1,934	1,929	1,925	1,920	1,932	1,962	2,026	23,369

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-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	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		(5,883)	(5,994)	(6,105)	(6,216)	(6,327)	(6,438)	(6,549)	(6,660)	(6,771)	(6,882)	(6,993)	(7,104)	(7,215)	
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)		$27,209	27,098	26,987	26,876	26,765	26,654	26,543	26,432	26,321	26,210	26,099	25,988	25,877	
6	Average Net Investment			27,153	27,042	26,931	26,820	26,709	26,598	26,487	26,376	26,265	26,154	26,043	25,932	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		253	251	250	249	248	247	246	245	244	243	242	241	$2,959
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		46	46	46	46	45	45	45	45	45	44	44	44	541
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,332
	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	0.010707		30	30	30	30	30	30	30	30	30	30	30	30	360
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			440	438	437	436	434	433	432	431	430	428	427	426	5,192
	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			440	438	437	436	434	433	432	431	430	428	427	426	5,192

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			($2,804)	$37	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,769)
	b. Clearings to Plant			(2,804)	37	(2)	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		$1,664,433	1,661,629	1,661,666	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		(63,467)	(68,161)	(72,855)	(84,389)	(89,083)	(93,777)	(98,471)	(96,325)	(101,019)	(105,713)	(110,407)	(115,101)	(119,795)	
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)		$1,600,966	1,593,468	1,588,811	1,577,275	1,572,581	1,567,887	1,563,193	1,565,339	1,560,645	1,555,951	1,551,257	1,546,563	1,541,869	
6	Average Net Investment			1,597,217	1,591,139	1,583,043	1,574,928	1,570,234	1,565,540	1,564,266	1,562,992	1,558,298	1,553,604	1,548,910	1,544,216	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		14,854	14,798	14,722	14,647	14,603	14,560	14,548	14,536	14,492	14,449	14,405	14,361	$174,975
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		2,715	2,705	2,691	2,677	2,669	2,661	2,659	2,657	2,649	2,641	2,633	2,625	31,982
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.39%		4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	56,328
	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	0.007614		1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	12,648
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			23,317	23,251	23,161	23,072	23,020	22,969	22,955	22,941	22,889	22,838	22,786	22,734	275,933
	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			23,317	23,251	23,161	23,072	23,020	22,969	22,955	22,941	22,889	22,838	22,786	22,734	275,933

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	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		(6,681)	(9,201)	(9,721)	(10,241)	(10,761)	(11,281)	(11,801)	(12,321)	(12,841)	(13,361)	(13,881)	(14,401)	(14,921)	
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)		$170,257	169,737	169,217	168,697	168,177	167,657	167,137	166,617	166,097	165,577	165,057	164,537	164,017	
6	Average Net Investment			169,997	169,477	168,957	168,437	167,917	167,397	166,877	166,357	165,837	165,317	164,797	164,277	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,581	1,576	1,571	1,566	1,562	1,557	1,552	1,547	1,542	1,537	1,533	1,528	$18,652
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		289	288	287	286	285	285	284	283	282	281	280	279	3,409
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.49%		520	520	520	520	520	520	520	520	520	520	520	520	6,240
	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	0.009194		137	137	137	137	137	137	137	137	137	137	137	137	1,644
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,527	2,521	2,515	2,509	2,504	2,499	2,493	2,487	2,481	2,475	2,470	2,464	29,945
	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			2,527	2,521	2,515	2,509	2,504	2,499	2,493	2,487	2,481	2,475	2,470	2,464	29,945

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			($85,614)	($2,804)	$0	$0	$0	$0	$428	$13,519	$3,608	$0	$285	($285)	($70,863)
	b. Clearings to Plant			365,936	(2,804)	0	0	0	0	428	13,519	3,608	0	285	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		$349,609	715,545	712,740	712,740	712,740	712,740	712,740	713,168	726,687	730,295	730,295	730,580	730,580	
3	Less: Accumulated Depreciation		(7,419)	(8,600)	(10,180)	(11,760)	(13,340)	(14,920)	(16,500)	(18,081)	(19,692)	(21,311)	(22,930)	(24,549)	(26,168)	
4	CWIP - Non-Interest Bearing		451,549	0	0	0	0	0	0	0	0	0	0	0	(285)	
5	Net Investment (Lines 2 + 3 + 4)		$793,740	706,945	702,561	700,981	699,401	697,821	696,241	695,087	706,995	708,984	707,365	706,031	704,127	
6	Average Net Investment			750,342	704,753	701,771	700,191	698,611	697,031	695,664	701,041	707,990	708,175	706,698	705,079	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		6,978	6,554	6,526	6,512	6,497	6,482	6,470	6,520	6,584	6,586	6,572	6,557	$78,838
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,276	1,198	1,193	1,190	1,188	1,185	1,183	1,192	1,204	1,204	1,201	1,199	14,413
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.56%		1,181	1,580	1,580	1,580	1,580	1,580	1,581	1,611	1,619	1,619	1,619	1,619	18,749
	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	0.008313		496	494	494	494	494	494	494	503	506	506	506	506	5,987
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,931	9,826	9,793	9,776	9,759	9,741	9,728	9,826	9,913	9,915	9,898	9,881	117,987
	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			9,931	9,826	9,793	9,776	9,759	9,741	9,728	9,826	9,913	9,915	9,898	9,881	117,987

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$135	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$135
	b. Clearings to Plant		135	0	0	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	$1,037,064	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	(17,976)	(20,742)	(23,508)	(26,274)	(29,040)	(31,806)	(34,572)	(37,338)	(40,104)	(42,870)	(45,636)	(48,402)	(51,168)	
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)	$1,019,088	1,016,457	1,013,691	1,010,925	1,008,159	1,005,393	1,002,627	999,861	997,095	994,329	991,563	988,797	986,031	
6	Average Net Investment		1,017,773	1,015,074	1,012,308	1,009,542	1,006,776	1,004,010	1,001,244	998,478	995,712	992,946	990,180	987,414	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		9,465	9,440	9,414	9,389	9,363	9,337	9,312	9,286	9,260	9,234	9,209	9,183	$111,892
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,730	1,726	1,721	1,716	1,712	1,707	1,702	1,697	1,693	1,688	1,683	1,679	20,454
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 3.20%		2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	33,192
	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 0.008454		731	731	731	731	731	731	731	731	731	731	731	731	8,772
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,692	14,663	14,632	14,602	14,572	14,541	14,511	14,480	14,450	14,419	14,389	14,359	174,310
	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		14,692	14,663	14,632	14,602	14,572	14,541	14,511	14,480	14,450	14,419	14,389	14,359	174,310

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$23,085	$3,657	$9,173	$10,216	$354,724	$285,856	$134,479	$337,573	$114,779	$321,552	$85,638	$272,696	$1,963,428
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	313,275	
	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	313,275	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(304)	
4	CWIP - Non-Interest Bearing	4,064	27,149	30,806	39,980	50,196	404,920	690,776	825,255	1,162,827	1,277,607	1,599,158	1,684,796	1,644,217	
5	Net Investment (Lines 2 + 3 + 4)	$4,064	27,149	30,806	39,980	50,196	404,920	690,776	825,255	1,162,827	1,277,607	1,599,158	1,684,796	1,957,188	
6	Average Net Investment		15,607	28,978	35,393	45,088	227,558	547,848	758,015	994,041	1,220,217	1,438,382	1,641,977	1,820,992	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		145	269	329	419	2,116	5,095	7,050	9,245	11,348	13,377	15,270	16,935	$81,598
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		27	49	60	77	387	931	1,289	1,690	2,074	2,445	2,791	3,096	14,916
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.33%		0	0	0	0	0	0	0	0	0	0	0	304	304
	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 0.008670		0	0	0	0	0	0	0	0	0	0	0	226	226
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		172	318	389	496	2,503	6,026	8,339	10,935	13,422	15,822	18,061	20,561	97,044
	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	318	389	496	2,503	6,026	8,339	10,935	13,422	15,822	18,061	20,561	97,044

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Unitversity of Florida (Project 4.1h)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	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		(18,270)	(19,064)	(19,858)	(20,652)	(21,446)	(22,240)	(23,034)	(23,828)	(24,622)	(25,416)	(26,210)	(27,004)	(27,798)	
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)		$123,164	122,370	121,576	120,782	119,988	119,194	118,400	117,606	116,812	116,018	115,224	114,430	113,636	
6	Average Net Investment			122,767	121,973	121,179	120,385	119,591	118,797	118,003	117,209	116,415	115,621	114,827	114,033	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,142	1,134	1,127	1,120	1,112	1,105	1,097	1,090	1,083	1,075	1,068	1,061	$13,214
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		209	207	206	205	203	202	201	199	198	197	195	194	2,416
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.74%		794	794	794	794	794	794	794	794	794	794	794	794	9,528
	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	0.014338		169	169	169	169	169	169	169	169	169	169	169	169	2,028
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,314	2,304	2,296	2,288	2,278	2,270	2,261	2,252	2,244	2,235	2,226	2,218	27,186
	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			2,314	2,304	2,296	2,288	2,278	2,270	2,261	2,252	2,244	2,235	2,226	2,218	27,186

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Intermediate

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	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		($5,609)	(7,240)	(8,871)	(10,502)	(12,133)	(13,764)	(15,395)	(8,482)	(9,290)	(10,098)	(10,906)	(11,714)	(12,522)	
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)		$284,689	283,058	281,427	279,796	278,165	276,534	274,903	281,816	281,008	280,200	279,392	278,584	277,776	
6	Average Net Investment			283,873	282,242	280,611	278,980	277,349	275,718	278,359	281,412	280,604	279,796	278,988	278,180	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,640	2,625	2,610	2,595	2,579	2,564	2,589	2,617	2,610	2,602	2,595	2,587	$31,213
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		483	480	477	474	471	469	473	478	477	476	474	473	5,705
	c. Other			0	0	0	0	0	0	214	0	0	0	0	0	214
8	Investment Expenses															
	a. Depreciation	3.34%		1,631	1,631	1,631	1,631	1,631	1,631	808	808	808	808	808	808	14,634
	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	0.007299		347	347	347	347	347	347	177	177	177	177	177	177	3,144
	e. Other			0	0	0	0	0	0	(9,382)	0	0	0	0	0	(9,382)
9	Total System Recoverable Expenses (Lines 7 + 8)			5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528
	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			5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2)
(in Dollars)

Base

Line	Description	Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,531,216	$757	$336,869	$1,868,842
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	$1,868,841	
	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	$0	0	0	0	0	0	0	0	0	0	0	0	1,868,841	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(2,204)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	1,531,216	1,531,973	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	1,531,216	1,531,973	1,866,638	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	765,608	1,531,594	1,699,305	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	0	0	0	7,120	14,244	15,804	$37,168
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	1,302	2,604	2,889	6,795
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.83%		0	0	0	0	0	0	0	0	0	0	0	2,204	2,204
	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 0.010707		0	0	0	0	0	0	0	0	0	0	0	1,667	1,667
	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	8,422	16,848	22,564	47,834
	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	8,422	16,848	22,564	47,834

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

ALL Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			($14,948)	$604	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($14,343)
	b. Clearings to Plant			(14,948)	604	0	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		$176,097	161,150	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		(384)	(626)	(869)	(1,112)	(1,355)	(1,171)	(1,349)	(1,527)	(1,705)	(1,883)	(2,061)	(2,239)	(2,417)	
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)		$175,714	160,524	160,885	160,642	160,399	160,583	160,405	160,227	160,049	159,871	159,693	159,515	159,337	
6	Average Net Investment			168,119	160,705	160,764	160,521	160,491	160,494	160,316	160,138	159,960	159,782	159,604	159,426	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,564	1,495	1,495	1,493	1,503	1,493	1,491	1,489	1,488	1,486	1,484	1,483	$17,964
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		286	273	273	273	275	273	273	272	272	272	271	271	3,284
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.32%		242	243	243	243	(184)	178	178	178	178	178	178	178	2,033
	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	0.009194		123	124	124	124	124	124	124	124	124	124	124	124	1,487
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,215	2,135	2,135	2,133	1,718	2,068	2,066	2,063	2,062	2,060	2,057	2,056	24,768
	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			2,215	2,135	2,135	2,133	1,718	2,068	2,066	2,063	2,062	2,060	2,057	2,056	24,768

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$4,344	$4,096	$653	$266	$0	$0	$0	$0	$0	$0	$0	$0	$9,359
	b. Clearings to Plant			4,344	4,096	653	266	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		$265,988	270,331	274,428	275,080	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3	Less: Accumulated Depreciation		(1,386)	(2,350)	(3,329)	(4,310)	(5,292)	(4,852)	(5,611)	(6,370)	(7,129)	(7,888)	(8,647)	(9,406)	(10,165)	
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)		$264,602	267,982	271,099	270,771	270,055	270,495	269,736	268,977	268,218	267,459	266,700	265,941	265,182	
6	Average Net Investment			266,292	269,541	270,935	270,413	270,275	270,116	269,357	268,598	267,839	267,080	266,321	265,562	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,477	2,507	2,520	2,515	2,544	2,512	2,505	2,498	2,491	2,484	2,477	2,470	$30,000
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		453	458	461	460	465	459	458	457	455	454	453	451	5,484
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.31%		964	979	981	982	(440)	759	759	759	759	759	759	759	8,779
	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	0.008313		187	190	191	191	191	191	191	191	191	191	191	191	2,287
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,081	4,134	4,153	4,148	2,760	3,921	3,913	3,905	3,896	3,888	3,880	3,871	46,550
	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			4,081	4,134	4,153	4,148	2,760	3,921	3,913	3,905	3,896	3,888	3,880	3,871	46,550

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$403	$2,104	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,508
	b. Clearings to Plant			403	2,104	0	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		$196,480	196,884	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		(715)	(1,214)	(1,718)	(2,222)	(2,726)	(2,795)	(3,231)	(3,667)	(4,103)	(4,539)	(4,975)	(5,411)	(5,847)	
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)		$195,766	195,670	197,270	196,766	196,262	196,193	195,757	195,321	194,885	194,449	194,013	193,577	193,141	
6	Average Net Investment			195,718	196,470	197,018	196,514	196,228	195,975	195,539	195,103	194,667	194,231	193,795	193,359	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,820	1,827	1,832	1,828	1,835	1,823	1,819	1,814	1,810	1,806	1,802	1,798	$21,814
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		333	334	335	334	336	333	332	332	331	330	329	329	3,988
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.63%		499	504	504	504	69	436	436	436	436	436	436	436	5,132
	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	0.008313		136	138	138	138	138	138	138	138	138	138	138	138	1,654
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,788	2,803	2,809	2,804	2,378	2,730	2,725	2,720	2,715	2,710	2,705	2,701	32,588
	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			2,788	2,803	2,809	2,804	2,378	2,730	2,725	2,720	2,715	2,710	2,705	2,701	32,588

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$897	$319	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,217
	b. Clearings to Plant			897	319	0	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		$86,450	87,348	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		(373)	(590)	(808)	(1,026)	(1,244)	(1,663)	(1,911)	(2,159)	(2,407)	(2,655)	(2,903)	(3,151)	(3,399)	
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)		$86,078	86,758	86,860	86,642	86,424	86,005	85,757	85,509	85,261	85,013	84,765	84,517	84,269	
6	Average Net Investment			86,418	86,809	86,751	86,533	86,214	85,881	85,633	85,385	85,137	84,889	84,641	84,393	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		804	807	807	805	797	799	796	794	792	789	787	785	$9,562
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		147	148	147	147	145	146	146	145	145	144	144	143	1,747
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.39%		217	218	218	218	419	248	248	248	248	248	248	248	3,026
	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	0.008670		63	63	63	63	63	63	63	63	63	63	63	63	756
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,231	1,236	1,235	1,233	1,424	1,256	1,253	1,250	1,248	1,244	1,242	1,239	15,091
	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			1,231	1,236	1,235	1,233	1,424	1,256	1,253	1,250	1,248	1,244	1,242	1,239	15,091

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2008 through December 2008
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$4,593	$925	$384	$2,371	$20,457	$26,428	($20,026)	$0	$0	$0	$0	$0	$35,133
	b. Clearings to Plant			314,950	925	384	2,371	20,457	26,428	(20,026)	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	314,950	315,875	316,259	318,630	339,087	365,516	345,490	345,490	345,490	345,490	345,490	345,490	
3	Less: Accumulated Depreciation		0	(512)	(1,539)	(2,567)	(3,603)	(1,208)	(1,513)	(1,801)	(2,089)	(2,377)	(2,665)	(2,953)	(3,241)	
4	CWIP - Non-Interest Bearing		310,357	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$310,357	314,438	314,336	313,692	315,027	337,879	364,003	343,689	343,401	343,113	342,825	342,537	342,249	
6	Average Net Investment			312,397	314,387	314,014	314,360	326,453	350,941	353,846	343,545	343,257	342,969	342,681	342,393	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,905	2,924	2,920	2,924	3,080	3,264	3,291	3,195	3,192	3,190	3,187	3,184	$37,256
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		531	534	534	534	563	597	602	584	584	583	583	582	6,811
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.00%		512	1,027	1,028	1,036	(2,395)	305	288	288	288	288	288	288	3,241
	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	0.008313		218	219	219	221	235	253	239	239	239	239	239	239	2,799
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,166	4,704	4,701	4,715	1,483	4,419	4,420	4,306	4,303	4,300	4,297	4,293	50,107
	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			4,166	4,704	4,701	4,715	1,483	4,419	4,420	4,306	4,303	4,300	4,297	4,293	50,107

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$21,336	$319	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,656
	b. Clearings to Plant			21,336	319	0	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		$327,928	349,264	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		(2,291)	(3,921)	(5,552)	(7,183)	(8,814)	(4,905)	(5,671)	(6,437)	(7,203)	(7,969)	(8,735)	(9,501)	(10,267)	
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)		$326,637	345,343	344,032	342,401	340,770	344,679	343,913	343,147	342,381	341,615	340,849	340,083	339,317	
6	Average Net Investment			335,490	344,687	343,216	341,585	342,724	344,296	343,530	342,764	341,998	341,232	340,466	339,700	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,120	3,206	3,192	3,177	3,307	3,202	3,195	3,188	3,181	3,173	3,166	3,159	$38,266
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		570	586	583	581	605	585	584	583	581	580	579	577	6,994
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.63%		1,630	1,631	1,631	1,631	(3,909)	766	766	766	766	766	766	766	7,976
	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	0.007614		222	222	222	222	222	222	222	222	222	222	222	222	2,664
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,542	5,645	5,628	5,611	225	4,775	4,767	4,759	4,750	4,741	4,733	4,724	55,900
	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			5,542	5,645	5,628	5,611	225	4,775	4,767	4,759	4,750	4,741	4,733	4,724	55,900

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$3,590	$1,839	$276	$890	$0	$0	$0	$0	$0	$0	$0	$0	$6,594
	b. Clearings to Plant			3,590	1,839	276	890	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		$127,418	131,008	132,846	133,122	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3	Less: Accumulated Depreciation		(766)	(1,292)	(1,826)	(2,361)	(2,899)	(1,953)	(2,259)	(2,565)	(2,871)	(3,177)	(3,483)	(3,789)	(4,095)	
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)*		$126,652	*129,716*	*131,021*	*130,761*	*131,113*	*132,059*	*131,753*	*131,447*	*131,141*	*130,835*	*130,529*	*130,223*	*129,917*	
6	Average Net Investment			128,184	130,368	130,891	130,937	131,586	131,906	131,600	131,294	130,988	130,682	130,376	130,070	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,192	1,212	1,217	1,218	1,256	1,227	1,224	1,221	1,218	1,215	1,212	1,210	$14,622
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		218	222	223	223	230	224	224	223	223	222	222	221	2,675
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.74%		526	534	535	538	(946)	306	306	306	306	306	306	306	3,329
	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	0.008974		98	99	100	100	100	100	100	100	100	100	100	100	1,197
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,034	2,067	2,075	2,079	640	1,857	1,854	1,850	1,847	1,843	1,840	1,837	21,823
	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			2,034	2,067	2,075	2,079	640	1,857	1,854	1,850	1,847	1,843	1,840	1,837	21,823

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$3,101	$1,541	$3,877	$1,200	$0	$0	$0	$0	$0	$0	$0	$0	$9,718
	b. Clearings to Plant			374,942	1,541	3,877	1,200	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	374,942	376,483	380,360	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation		0	(670)	(2,016)	(3,376)	(4,740)	(3,016)	(3,690)	(4,364)	(5,038)	(5,712)	(6,386)	(7,060)	(7,734)	
4	CWIP - Non-Interest Bearing		371,841	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$371,841	374,272	374,467	376,984	376,820	378,544	377,870	377,196	376,522	375,848	375,174	374,500	373,826	
6	Average Net Investment			373,057	374,370	375,725	376,902	377,682	378,207	377,533	376,859	376,185	375,511	374,837	374,163	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,469	3,482	3,494	3,505	3,552	3,517	3,511	3,505	3,499	3,492	3,486	3,480	$41,992
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		634	636	639	641	649	643	642	641	640	638	637	636	7,676
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.12%		670	1,346	1,360	1,364	(1,724)	674	674	674	674	674	674	674	7,734
	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	0.008454		264	265	268	269	269	269	269	269	269	269	269	269	3,218
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,037	5,729	5,761	5,779	2,746	5,103	5,096	5,089	5,082	5,073	5,066	5,059	60,620
	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			5,037	5,729	5,761	5,779	2,746	5,103	5,096	5,089	5,082	5,073	5,066	5,059	60,620

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2008 through December 2008
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR/CAMR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$52,616	($197,964)	68,803	408,413	$0	$134,790	$1	$466,658
	b. Clearings to Plant			0	0	0	0	15,150,677	101,267	$298,338	67,809	408,520	(665)	136,729	1	
	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	15,150,677	15,251,944	15,550,281	15,618,090	16,026,610	16,025,945	16,162,674	16,162,675	
3	Less: Accumulated Depreciation		0	0	0	0	0	(21,401)	(64,488)	(108,418)	(152,539)	(197,814)	(243,087)	(288,747)	(334,407)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	(48,651)	0	0	0	(665)	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	15,129,277	15,138,805	15,441,864	15,465,552	15,828,797	15,782,193	15,873,928	15,828,268	
6	Average Net Investment			0	0	0	0	7,564,638	15,134,041	15,290,334	15,453,708	15,647,175	15,805,495	15,828,061	15,851,098	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	70,351	140,747	142,200	143,719	145,519	146,991	147,201	147,415	$1,084,143
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	12,860	25,728	25,994	26,271	26,600	26,869	26,908	26,947	198,177
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.39%		0	0	0	0	21,401	43,087	43,930	44,121	45,275	45,273	45,660	45,660	334,407
	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	0.010707		0	0	0	0	13,518	13,608	13,874	13,935	14,299	14,299	14,421	14,421	112,375
	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	118,130	223,170	225,998	228,046	231,693	233,432	234,190	234,443	1,729,102
	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	118,130	223,170	225,998	228,046	231,693	233,432	234,190	234,443	1,729,102

For Project: CAIR/CAMR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Intermediate

Line	Description		Beginning of Period Amount	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$308,085	$308,085
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	5,599,409	
	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	5,599,409	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(6,603)	
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	5,592,806	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	2,796,403	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	0	0	0	0	0	0	0	26,007	$26,007
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	0	4,754	4,754
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		0	0	0	0	0	0	0	0	0	0	0	6,603	6,603
	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	0.010707		0	0	0	0	0	0	0	0	0	0	0	4,996	4,996
	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	42,360	42,360
	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	42,360	42,360

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 22
COMPANY Progress Energy Florida, Inc.
WITNESS Patricia Q. West (PQW-1) (Confidential)
DATE 11/02/09

Docket No. 090007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No. __ (PQW-1)

REDACTED

Progress Energy Florida

Review of Integrated Clean Air Compliance Plan

Submitted to the
Florida Public Service Commission

April 1, 2009

Progress Energy

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Executive Summary

In the 2007 Environmental Cost Recovery Clause (ECRC) Docket (No. 070007-EI) and as reaffirmed in the 2008 ECRC Docket (No. 080007-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), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR) and related regulatory requirements. 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." This report provides the required review for 2009.

The primary components of PEF's Compliance Plan "D" are summarized as follows:

Sulfur Dioxide (SO_2):

- Installation of wet scrubbers, flue gas desulphurization 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
- Purchase of mercury (Hg) allowances

As detailed in PEF's 2007 ECRC filing, PEF decided upon 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 is expected to meet environmental 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 reviewed the efficacy of Plan D and the cost-effectiveness of retrofit options in relation to expected changes in environmental regulations. With regard to Plan D's efficacy, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. PEF has achieved several project milestones, including:

- Completion of the access road in May, 2008;
- Completion of the vehicle barrier system in May, 2008;
- Completion of the flue gas chimney shell in June, 2008;
- Completion of the Crystal River Unit 5 FGD absorber tower in September, 2008; and
- Completion of the Crystal River Unit 4 LNB/AH in December, 2008

Although there are uncertainties associated with all major construction projects of this type, the Crystal River projects currently are on-schedule to achieve compliance with the applicable regulations.

As a result of a 2008 federal appeals court decision vacating the federal CAMR regulations, the U.S. Environmental Protection Agency (EPA) is proceeding with adoption of new standards for utility mercury emissions. This development does not immediately impact PEF's implementation of Plan D because the plan does not contemplate installation of mercury-specific controls until 2017 if necessary. Thus, Plan D provides PEF flexibility to respond when EPA adopts any new mercury standards.

Since last year's filing, a federal appellate court also issued a decision remanding CAIR to the EPA to correct several flaws identified by the court. Although the court originally vacated the rule, in response to EPA's petition for rehearing, the court subsequently decided to remand CAIR without vacating it, thereby leaving the rule and its compliance obligations in place.

No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. In 2008, the Florida Legislature adopted legislation authorizing the Florida Department of Environmental Protection (FDEP) to adopt rules establishing a cap-and-trade program to regulate emissions of greenhouse gases, such as carbon dioxide (CO_2). To date, FDEP has not adopted any cap-and-trade rules and, under the legislation, any such rules must be ratified by the Legislature, however, the FDEP has begun the rulemaking process and held a public workshop on March 11, 2009. Nevertheless, PEF is taking steps to reduce CO_2 emissions consistent with the state's goals. Among other things, the Company has agreed to retire Crystal River Units 1 and 2 as coal-fired units after the second of two new, advanced design nuclear units in Levy County completes its first fuel cycle. This will reduce PEF's CO_2 emissions by approximately 5 million tons per year.

There currently are no demonstrated retrofit options 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. Likewise, replacement of coal-fired generation from Crystal River Units 4 and 5 with natural-gas fired generation is not a feasible or cost-effective option because it cannot be implemented in time to meet the 2009 and 2010 CAIR deadlines and it would put PEF in the vulnerable position of relying solely on SO_2 and NOx allowance purchases to achieve compliance during the five to six year interim period it would take to construct a new generating facility. Furthermore, replacing coal-fired generation with gas-fired generation would decrease PEF's fuel diversity and potentially increase fuel price volatility.

I. Introduction

In its final order in the 2007 ECRC Docket (No. 070007-EI) and as reaffirmed in the 2008 ECRC Docket (No. 080007-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 2009.

II. PEF's Integrated Clean Air Compliance Plan

A. Background

The CAIR and CAVR programs require PEF and other utilities to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx). Under CAIR, these reductions must be met in incremental phases. Phase I begins in 2009 for NOx and in 2010 for SO_2. Phase II begins in 2015 for both NOx and SO_2.

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. 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.

B. PEF's Plan "D"

PEF's compliance plan (Plan D) meets the applicable environmental requirements by striking a good 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. Specific components of the Plan are summarized below.

1. CAIR SO_2 Plan

The most significant component of PEF's Integrated Clean Air Compliance Plan is the installation of flue gas desulfurization (FGD) systems, also known as wet scrubbers, on Crystal River Units 4 and 5 to comply with CAIR's SO_2 requirements. PEF also plans to purchase limited SO_2 allowances. The plan also includes switching Crystal River Units 1 and 2 to burn low-sulfur (1.2 lbs SO_2/mmBtu) "compliance" coal, and burning low sulfur oil at Anclote Units 1 and 2. However, the final decision to switch fuels will be made closer to implementation time. The fuel to be burned by PEF at these units will be that which has the lowest overall cost when the cost of allowances is factored into the overall cost along with other relevant fuel selection considerations.

2. CAIR NOx Plan

The primary component of PEF's NOx compliance plan is the installation of low NOx burners (LNBs) and selective catalytic reduction (SCR) systems on Crystal River Units 4 and 5. Currently, the Plan also includes installation of LNB/SOFA controls to reduce NOx emissions from the Anclote units. However, additional study of this option is required. These control options are among the lowest incremental cost options available, and provide most, but not all, of the NOx reductions required by CAIR. Alternative technology trials and studies for alternative NOx controls are being evaluated to more thoroughly quantify costs, effectiveness, benefits, and risks. Technologies being evaluated for studies and trials include, but are not limited to, selective non-catalytic reduction (SNCR), fuel oil additives, and burner tip modifications. To

achieve compliance with CAIR, PEF plans to take strategic advantage of CAIR's cap-and-trade feature by purchasing some annual and ozone season NOx allowances.

3. Mercury Plan

As discussed more fully below, a federal appeals court vacated the federal CAMR regulations in 2008. With CAMR vacated, PEF is not required at this time to install mercury controls to meet the CAMR emission limits. This development does not have any immediate, significant impact on PEF's implementation of Plan D because installation of NOx and SO_2 controls on Crystal River Units 4 and 5 is expected to reduce mercury emissions by at least 80% and the plan did not contemplate installation of any mercury-specific controls until 2017. PEF will continue to monitor the regulatory developments related to utility mercury emissions as well as research and development of mercury control technologies to ensure that the most reliable and cost-effective control technology is used when the time arrives for compliance.

4. CAVR Visibility Plan

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. As indicated above, PEF's Compliance Plan includes switching to low-sulfur oil and the installation of LNBs at Anclote Units 1 and 2 or other alternative NOx controls such as selective non-catalytic reduction, fuel oil additives, combustion control technologies, and burner tip modifications. Per the FDEP's BART requirements, Rule 62-296.340, F.A.C., a BART determination is not required for SO_2 and NOx for any BART-eligible source that is subject to CAIR. Therefore, visibility impacts from particulate matter emissions are only evaluated for the BART determination. Based on modeled impact of particulate matter on visibility Anclote Units 1 and 2 were determined to be exempt from BART in April 2008. Because the results of the modeling for Crystal River Units 1 and 2 showed visibility impacts at or above regulatory threshold levels, PEF applied for a BART permit for those units. This permit was issued on February 26, 2009 and it establishes a combined BART emission standard for Crystal River Units 1 and 2. By establishing a combined emission standard, the permit enables PEF to cost-effectively satisfy BART requirements by maintaining the existing Unit 1 electrostatic precipitator (ESP) and upgrading the Unit 2 ESP if necessary,

III. Efficacy of PEF's Plan D

As noted above, in its Final Order in Docket No. 070007- EI, the Commission requested a review of the efficacy of PEF's Integrated Clean Air Compliance Plan (Plan D) and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations. With regard to Plan D's efficacy, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. As noted below, however, there are uncertainties that could affect the timing and costs of implementation.

A. Project Milestones

PEF remains on schedule to complete installation of controls on Crystal River Units 4 and 5 as contemplated in PEF's 2008 ECRC filing. As discussed in previous filings, PEF has executed contracts for specific project components, as well as an overall Engineering, Construction and Procurement (EPC) contract. Since the submittal of last year's annual review, PEF has achieved the following project milestones:

ACHIEVED CAIR COMPLIANCE MILESTONES

Access Road CRN – Common	Apr-08
Chimney Shell Complete – Common	May-08
Limestone Prep steel complete – Common	Jul-08
Scheduled Equipment Delivery complete – Crystal River Unit 4 LNB	Aug-08
FGD building steel complete – Crystal River Unit 5 FGD	Sep-08
SCR Steel complete – Crystal River Unit 5 SCR	Sep-08
SCR Foundation complete – Crystal River Unit 4 SCR	Sep-08
Access Road Piping delivered – Crystal River Unit 4 FGD	Oct-08
Air pre-heater baskets delivered – Crystal River Unit 5 FGD	Dec-08
LNB scheduled equipment delivery complete – Crystal River Unit 5 SCR	Dec-08
Urea equipment delivery – Common	Dec-08
Crystal River Unit 4 LNB Installation complete	Dec-08

PEF expects to achieve the following project milestones in 2009 and 2010:

UPCOMING CAIR COMPLIANCE MILESTONES

FGD building steel delivery complete - Crystal River Unit 4 FGD	Mar-09	
[redacted]	[redacted]	1
[redacted]	[redacted]	2
Limestone handling complete – Common	Sep - 09	
[redacted]	[redacted]	3
SCR Steel erection work complete - Crystal River Unit 4 SCR	Dec-09	
[redacted]	[redacted]	4
[redacted]	[redacted]	5
[redacted]	[redacted]	6

B. Projects Costs

During 2008, PEF had incurred approximately $568 million in capital costs for the Crystal River projects. The 2008 figure includes approximately $511 million in contract billings, $13 million of owner's costs, and $44 million of AFUDC. As of December 2008, the life-to-date capital costs were approximately $897 million. This figure includes approximately $812 million in contract billings, $34 million of owner's costs, and $51 million of AFUDC. The contract billings include payments for: major construction work, design and engineering work, procurement of major equipment, and environmental permits. The overall budget, excluding AFUDC, is $1.15 billion. Currently, the costs are on track to be completed within the overall budget.

C. Uncertainties

While a significant amount of study, engineering, and analysis have been completed and construction has begun on the Crystal River projects, there are still a number of uncertainties that could affect project schedules and costs. Although most of PEF's contracts contain provisions for liquidated damages for delays, the non-performance of contractors, force majeure events, and other uncertainties could adversely impact project schedules and costs. The primary risks identified on the PEF CAIR compliance projects are as follows:

- **EPCR adherence to the outage schedules:** EPCR has finalized the schedule according to the planned outage dates. PEF personnel will monitor the schedule and identify any potential issues.

- **Force Majeure:** There is a risk of a major storm impacting this project considering the location is directly on the Gulf Coast.

- **Scope Modifications:** There are risks of design errors, quantity changes, site conditions, site interferences, change requests or other items which would require additional scope. A project contingency has been developed to cover these unknowns. A process is in place to track these contingencies on a monthly basis in order to trend and project future costs.

- **Condition of Certification (COC) Modification delay:** A lengthy delay in the FDEP's approval of the Gypsum Storage Pad design could create a delay in receiving the necessary modifications to the existing Conditions of Certification for Crystal River Units 4 and 5. This approval is now expected by the end of April 2009.

Primary risks to date are discussed above; however, emergent risks could still occur. Project contingency has been developed to cover these project unknowns, and PEF project staff members are actively engaged to minimize or avoid any project schedule impacts.

IV. Retrofit Options in Relation to Expected Changes in Environmental Regulations

Since PEF's filing in the 2008 ECRC docket, no new or revised environmental regulations have been adopted that have a direct bearing on Plan D. Furthermore, at this time, it is not possible to predict the timing or requirements of any environmental regulations that may be adopted in the future. The following discussion addresses three regulatory developments that have been the topic of discussion since PEF's 2008 filing.

A. Status of CAIR

In July 2008, the U.S. Circuit Court of Appeals for the District of Columbia issued a decision vacating CAIR in its entirety. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). However, in response to EPA's petition for rehearing, the court requested briefs from the parties regarding whether CAIR should be remanded to EPA without vacatur of CAIR. On December 23, the court decided to remand CAIR without vacatur, thereby leaving the rule and its compliance obligations in place. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008). Thus, PEF must continue to move forward with its Integrated Clean Air Compliance Plan in order to meet the impending CAIR compliance deadlines.

B. Status of CAMR

In February 2008, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit vacated the federal CAMR regulations. *See, New Jersey v. EPA*, 517 F. 3d 574 (D.C. Cir. 2008). EPA originally promulgated CAMR under Section 111 of the Clean Air Act (CAA), rather than CAA Section 112, which requires EPA to establish Maximum Achievable Control Technology (MACT) standards for hazardous air pollutants. EPA's decision to proceed under CAA Section 111 was based on its rescission of a prior finding in 2000 that emissions of mercury and other hazardous pollutants from electric generating units should be regulated under CAA Section 112. In its decision, the D.C. Circuit court vacated EPA's rescission of its 2000 finding, holding that the CAA required EPA, prior to making such a rescission, to determine that no utility-unit's mercury emissions exceeded a level that would "protect public health with an ample margin of safety and [have] no adverse environmental effect." Based on this threshold conclusion, the court then vacated CAMR because it was based on EPA's rescission. Since last year's filing, the U.S. Supreme Court has denied review of the D.C. Circuit's vacatur of CAMR and EPA has announced its intention to proceed with a MACT rulemaking.

It is impossible to predict when EPA will complete the MACT rulemaking process or what the emissions standards will be. In any event, because PEF's Plan D relies on the co-benefit of SCR/scrubbers rather than mercury-specific controls until 2017, the Plan provides flexibility to respond to any rules EPA may adopt in response to the D.C. Circuit's decision.

C. Potential Greenhouse Gas Regulation

When PEF committed to placing environmental controls on Crystal River Units 4 and 5, climate change issues were only beginning to be discussed. At that time, PEF had to commit to installing controls in order to meet the fast approaching 2009 and 2010 CAIR compliance deadlines. Governor Crist subsequently 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. At this time, however, FDEP is still in the early stages of developing cap-and-trade rules and numerous key issues remain unresolved, such as the approach to allowance distribution and whether Florida should join a regional program; a rulemaking workshop was held on March 11, 2009. Until such regulations are adopted and ratified, or legislation is enacted at the federal level, the potential impact of CO_2 regulation will remain uncertain. Nevertheless, PEF is taking steps to reduce CO_2 emissions consistent with the state's goals. In December 2008, the Company announced an agreement with FDEP to retire Crystal River Units 1 and 2 coal-fired units after the second of two new, advanced design nuclear units in Levy County completes its first fuel cycle. Retiring the coal-fired Crystal River Units 1 and 2 will reduce PEF's CO_2 emissions by 5 million tons per year.

At this time, 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 sequestration 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. Likewise, replacing coal-fired generation from Crystal River Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation[1] is not a viable option. PEF has already incurred over 73% of the costs, excluding

[1] The CO_2 emission rate for natural gas-fired combined cycle (NG/CC) units is approximately 50% of the emission rate for coal-fired generating units. Thus, replacing coal-fired generation with NG/CC would not eliminate costs associated with any to-be-adopted CO_2 regulatory regime.

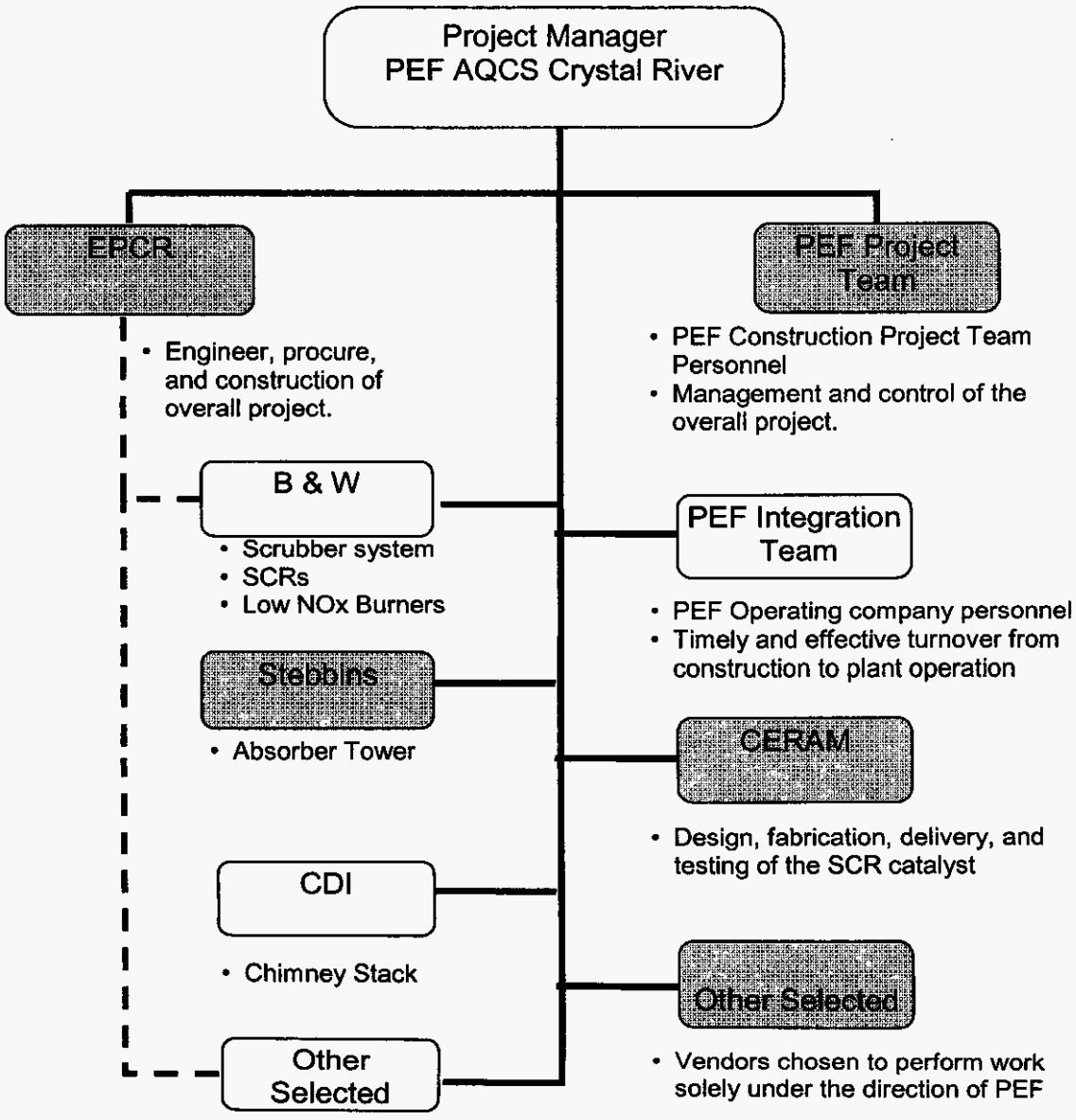
AFUDC, of Plan D and the major components of the Plan are due to be placed in service in 2009 and 2010. Even if PEF could abandon the Crystal River projects at this late date, sufficient combined-cycle generation could not be placed on-line until the 2015-2016 timeframe. PEF would have to rely solely on allowance markets to achieve and maintain CAIR compliance for five to six years until the combined cycle generation could be placed in service. Given the uncertainty of the CAIR allowance markets, PEF cannot reasonably assume sufficient allowances would be available at reasonable price if PEF were left in the extremely vulnerable position of relying solely on allowance purchases to achieve compliance. Furthermore, replacing Crystal River Units 4 and 5 with gas-fired generation would decrease PEF's fuel diversity and potentially increase fuel price volatility.

V. Conclusion

Based on project milestones achieved to date, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. Although FDEP is in the process of developing a cap-and-trade program to regulate CO_2 emissions, no regulations have been adopted to date and there currently are no demonstrated retrofit options to reduce CO_2 emissions from fossil fuel-fired electric generating units. Moreover, abandoning the Crystal River Units 4 and 5 emission control projects is not a viable option in light of the imminent 2009 and 2010 CAIR deadlines. Although EPA is proceeding with the adoption of new MACT standards for utility hazardous air pollutant emissions as a result of a federal court decision vacating the federal CAMR rules, this development does not immediately impact PEF's implementation of Plan D because the plan relies primarily on installation of NOx and SO_2 controls to reduce mercury emissions and does not contemplate installation of mercury-specific controls until 2017. For these reasons, PEF's Plan D continues to represent the most cost-effective alternative for achieving and maintaining compliance with the applicable regulatory requirements.

Docket No. 090007-EI
Progress Energy Florida
Witness: Dale Wilterdink
Exhibit No. __ (DW-1)
Crystal River Project Organizational Structure

1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 23
COMPANY Progress Energy Florida, Inc.
WITNESS KEVIN MURRAY (adopting WILTERDINK'S exhibit) (DW-1)
DATE 11/02/09

Witness: T.G. Foster
Exibit__(TGF-1)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-8E

JANUARY 2009 - DECEMBER 2009
Calculation of the Current Period Estimated/Actual Amount
Actuals for the period of January through June 2009
Estimated for the period of July through December 2009
DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 24
COMPANY Progress Energy Florida, Inc.
WITNESS Thomas G. Foster (LC-1)
DATE 11/02/09

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-1)
Page 1 of 24

Form 42-1E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period (Form 42-2E, Line 5)	$ 24,048,806
2	Interest Provision (Form 42-2E, Line 6)	26,775
3	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2009 to December 2009 (Lines 1 + 2 + 3)	**$ 24,075,581**

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-1)
Page 2 of 24

Form 42-2E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$9,341,113	$10,005,241	$8,865,089	$8,944,162	$9,976,839	$11,667,770	$ 12,284,738	$ 13,557,651	$ 13,721,854	$ 11,870,704	$ 10,322,832	$ 10,065,650	$130,623,643
2	True-Up Provision	($4,309,712)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(4,309,712)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		8,981,970	9,646,098	8,505,946	8,585,019	9,617,696	11,308,627	11,925,596	13,198,509	13,362,712	11,511,561	9,963,689	9,706,508	126,313,931
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5E, Line 9)		5,079,856	4,901,564	4,490,451	4,178,262	6,932,024	7,553,417	7,323,499	7,967,326	6,546,086	5,739,613	4,661,632	4,410,921	69,784,651
	b. Capital Investment Projects (Form 42-7E, Line 9)		1,293,974	1,301,474	1,295,301	1,267,463	1,256,962	1,874,230	2,888,054	3,270,500	3,213,494	3,163,626	3,121,727	8,533,669	32,480,474
	c. Total Jurisdictional ECRC Costs		6,373,830	6,203,038	5,785,752	5,445,725	8,188,986	9,427,647	10,211,553	11,237,826	9,759,580	8,903,239	7,783,359	12,944,590	102,265,125
5	Over/(Under) Recovery (Line 3 - Line 4c)		2,608,141	3,443,060	2,720,194	3,139,294	1,428,710	1,880,980	1,714,043	1,960,683	3,603,132	2,608,322	2,180,330	(3,238,082)	24,048,806
6	Interest Provision (Form 42-3E, Line 10)		(3,931)	(2,410)	(177)	1,184	1,626	2,058	2,836	3,474	4,386	5,392	6,192	6,145	26,775
7	Beginning Balance True-Up & Interest Provision		(4,309,712)	(1,346,360)	2,453,433	5,532,593	9,032,214	10,821,692	13,063,873	15,139,895	17,463,194	21,429,854	24,402,711	26,948,376	(4,309,712)
	a. Deferred True-Up from January 2008 to December 2008 (Order No. PSC-08-0775-FOF-EI)		(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)
8	True-Up Collected/(Refunded) (see Line 2)		359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	4,309,712
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		(5,666,966)	(1,867,173)	1,211,987	4,711,608	6,501,086	8,743,270	10,819,289	13,142,588	17,109,248	20,082,105	22,627,770	19,754,975	19,754,975
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)		($5,666,966)	($1,867,173)	$1,211,987	$4,711,608	$6,501,086	$8,743,270	$10,819,289	$13,142,588	$17,109,248	$20,082,105	$22,627,770	$19,754,975	$19,754,975

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-1)
Page 3 of 24

Form 42-3E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Interest Provision
(in Dollars)

Line	Description	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	**($8,630,318)**	($5,666,966)	($1,867,173)	$1,211,987	$4,711,608	$6,501,086	$8,743,267	$10,819,289	$13,142,588	$17,109,248	$20,082,105	$22,627,770	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	(5,663,035)	(1,864,763)	1,212,164	4,710,424	6,499,460	8,741,209	10,816,453	13,139,114	17,104,862	20,076,713	22,621,578	19,748,830	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	(14,293,353)	(7,531,728)	(655,009)	5,922,410	11,211,068	15,242,295	19,559,719	23,958,403	30,247,451	37,185,961	42,703,683	42,376,600	
4	Average True-Up Amount (Line 3 x 1/2)	(7,146,677)	(3,765,864)	(327,505)	2,961,205	5,605,534	7,621,148	9,779,860	11,979,202	15,123,726	18,592,981	21,351,842	21,188,300	
5	Interest Rate (First Day of Reporting Business Month)	0.54%	0.79%	0.75%	0.55%	0.40%	0.30%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
6	Interest Rate (First Day of Subsequent Business Month)	0.79%	0.75%	0.55%	0.40%	0.30%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.33%	1.54%	1.30%	0.95%	0.70%	0.65%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	
8	Average Interest Rate (Line 7 x 1/2)	0.665%	0.770%	0.650%	0.475%	0.350%	0.325%	0.350%	0.350%	0.350%	0.350%	0.350%	0.350%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.055%	0.064%	0.054%	0.040%	0.029%	0.027%	0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	
10	Interest Provision for the Month (Line 4 x Line 9)	($3,931)	($2,410)	($177)	$1,184	$1,626	$2,058	$2,836	$3,474	$4,386	$5,392	$6,192	$6,145	**$26,775**

PROGRESS ENERGY FLORIDA

Form 42-4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention - Demand	$2,378,173	$3,690,681	($1,312,508)	-36%
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention - Demand	1,724,902	3,140,557	(1,415,655)	-45%
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention - Demand	8,240,519	8,311,000	(70,481)	-1%
	3 Pipeline Integrity Management - Demand	1,101,000	1,101,000	0	0%
	4 Above Ground Tank Secondary Containment - Demand	0	0	0	N/A
	5 SO2 & NOx Emissions Allowances - Energy	52,637,496	71,976,198	(19,338,701)	-27%
	6 Phase II Cooling Water Intake - Demand	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	45,176	67,700	(22,524)	-33%
	7.4 CAIR/CAMR Crystal River - Base	1,463,838	1,429,627	34,211	2%
	7.4 CAIR/CAMR Crystal River - Energy	2,080,814	2,662,344	(581,530)	-22%
	7.4 CAIR/CAMR Crystal River - A&G	14,737	0	14,737	100%
	8 Arsenic Groundwater Standard - Base - Demand	0	77,669	(77,669)	-100%
	9 Sea Turtle - Coastal Street Lighting - Distrib - Demand	5,000	5,000	0	0%
	11 Modular Cooling Towers - Base - Demand	3,336,752	3,336,752	0	0%
	12 Greenhouse Gas Inventory and Reporting - Energy	14,000	56,680	(42,680)	-75%
	13 Mercury Total Daily Maximum Loads Monitoring - Energy	92,164	0	92,164	100%
2	Total O&M Activities - Recoverable Costs	**$73,134,571**	**$95,855,207**	**($22,720,636)**	-24%
3	Recoverable Costs Allocated to Energy	54,824,475	74,695,222	(19,870,747)	-27%
4	Recoverable Costs Allocated to Demand	18,310,097	21,159,986	(2,849,889)	-13%

Notes:

Column (1) is the End of Period Totals on Form 42-5E
Column (2) = Original projection Form 42-2P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Form 42-5E

O&M Activities
(in Dollars)

Line	Description	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$310,544	$231,198	$112,097	$172,601	$174,868	$338,708	$173,026	$173,026	$173,026	$173,026	$173,026	$173,026	$2,378,173
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	96,799	201,026	154,349	393,125	188,128	93,748	99,621	99,621	99,621	99,621	99,621	99,621	1,724,902
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	586,740	640,834	798,795	587,011	1,184,896	932,243	711,000	758,500	742,000	842,500	427,000	29,000	8,240,519
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	(120,417)	67,763	(4,034)	12,164	54,775	43,095	60,715	80,715	127,896	384,896	212,896	180,536	1,101,000
	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 - Energy	4,416,716	3,996,452	3,547,922	3,170,590	4,725,882	5,603,579	5,242,537	5,796,052	5,136,181	3,989,011	3,635,800	3,376,773	52,637,496
	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	1,288	(1,288)	0	0	0	0	0	0	0	0	0
	7.2 CAIR/CAMR - Peaking	0	0	39,069	1,288	4,819	0	0	0	0	0	0	0	45,176
	7.4 CAIR/CAMR Crystal River - Base	0	0	0	4,284	39,769	44,100	215,485	215,485	215,485	215,485	256,872	256,872	1,463,838
	7.4 CAIR/CAMR Crystal River - Energy	0	0	0	0	0	0	336,662	357,280	353,463	370,622	132,047	530,741	2,080,814
	7.4 CAIR/CAMR Crystal River - A&G	572	1,011	1,158	2,280	465	1,883	1,228	1,228	1,228	1,228	1,228	1,228	14,737
	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	833	833	833	833	833	833	5,000
	11 Modular Cooling Towers - Base	0	0	0	0	834,188	834,188	834,188	834,188		0	0	0	3,336,752
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	2,333	2,333	2,333	2,333	2,333	2,333	14,000
	13 Mecrury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	46,082	23,041	0	0	23,041	92,164
2	Total of O&M Activities	5,290,954	5,138,284	4,650,644	4,342,055	7,207,790	7,891,544	7,677,629	8,365,344	6,875,107	6,079,557	4,941,657	4,674,006	$73,134,571
3	Recoverable Costs Allocated to Energy	4,416,716	3,996,452	3,547,922	3,170,590	4,725,882	5,603,579	5,581,532	6,201,748	5,515,017	4,361,967	3,770,180	3,932,889	54,824,475
4	Recoverable Costs Allocated to Demand - Transm	310,544	231,198	112,097	172,601	174,868	338,708	173,026	173,026	173,026	173,026	173,026	173,026	2,378,173
	Recoverable Costs Allocated to Demand - Distrib	683,539	841,860	953,144	980,136	1,373,024	1,025,991	811,455	858,955	842,455	942,955	527,455	129,455	9,970,421
	Recoverable Costs Allocated to Demand - Prod-Base	0	0	0	4,284	873,957	878,288	1,049,673	1,049,673	215,485	215,485	256,872	256,872	4,800,590
	Recoverable Costs Allocated to Demand - Prod-Intm	(120,417)	67,763	(2,746)	10,876	54,775	43,095	60,715	80,715	127,896	384,896	212,896	180,536	1,101,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	39,069	1,288	4,819	0	0	0	0	0	0	0	45,176
	Recoverable Costs Allocated to Demand - A&G	572	1,011	1,158	2,280	465	1,883	1,228	1,228	1,228	1,228	1,228	1,228	14,737
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
6	Retail Transmission Demand Jurisdictional Factor	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
	Retail Production Demand Jurisdictional Factor - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Production Demand Jurisdictional Factor - Intm	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Production Demand Jurisdictional Factor - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
	Retail Production Demand Jurisdictional Factor - A&G	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	
7	Jurisdictional Energy Recoverable Costs (A)	4,274,498	3,845,387	3,428,357	3,064,376	4,573,709	5,433,231	5,359,945	5,940,654	5,280,629	4,170,913	3,603,915	3,775,160	52,750,794
8	Jurisdictional Demand Recoverable Costs - Transm (B)	219,235	163,219	79,137	121,851	123,452	239,118	122,151	122,151	122,151	122,151	122,151	122,151	1,678,918
	Jurisdictional Demand Recoverable Costs - Distrib (B)	680,784	838,467	949,303	976,186	1,367,491	1,021,856	808,184	855,493	839,059	939,154	525,329	128,933	9,930,239
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	0	0	0	4,016	819,361	823,421	984,100	984,100	202,024	202,024	240,825	240,825	4,500,696
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	(95,185)	53,564	(2,171)	8,597	43,297	34,065	47,993	63,802	101,097	304,245	168,286	142,706	870,296
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	34,763	1,146	4,288	0	0	0	0	0	0	0	40,197
	Jurisdictional Demand Recoverable Costs - A&G (B)	524	927	1,062	2,090	426	1,726	1,126	1,126	1,126	1,126	1,126	1,126	13,511
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$5,079,856	$4,901,564	$4,490,451	$4,178,262	$6,932,024	$7,553,417	$7,323,499	$7,967,326	$6,546,086	$5,739,613	$4,661,632	$4,410,921	$69,784,651

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Variance Report of Capital Investment Activities
(In Dollars)

Line		(1) Estimated/ Actual	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities				
	3.1 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate - Demand	$581,294	$606,258	($24,964)	-4%
	4.x Above Ground Tank Secondary Containment - Demand	1,756,027	1,612,041	143,986	9%
	5 SO2/NOx Emissions Allowances - Energy	7,656,333	6,974,894	681,439	10%
	7.x CAIR/CAMR - Demand/Energy	24,406,536	35,475,761	(11,069,225)	-31%
	9 Sea Turtle - Coastal Street Lighting -Distribution - Demand	2,692	7,202	(4,510)	-63%
	10.x Underground Storage Tanks-Base - Demand	40,475	40,453	22	0%
	11 Modular Cooling Towers - Base - Demand	176,235	176,379	(144)	0%
	11.1 Thermal Discharge Permanent Cooling Tower - Base - Demand	0	0	0	N/A
2	Total Capital Investment Activities - Recoverable Costs	**34,619,592**	**44,892,988**	**($10,273,396)**	-23%
3	Recoverable Costs Allocated to Energy	7,656,333	6,974,894	681,439	10%
4	Recoverable Costs Allocated to Demand	$26,963,259	$37,918,094	($10,954,835)	-29%

Notes:
Column (1) is the End of Period Totals on Form 42-7E
Column (2) = Original projection Form 42-3P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

PROGRESS ENERGY FLORIDA

Form 42-7E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Description of Investment Projects (A)													
3	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$48,725	$48,351	$48,671	$48,800	$48,813	$48,679	$48,545	$48,410	$48,276	$48,143	$48,008	$47,873	$581,294
4.1	Above Ground Tank Secondary Containment - Peaking	98,857	103,069	104,497	105,927	111,749	115,907	117,039	118,577	120,199	120,558	122,234	124,294	1,362,907
4.2	Above Ground Tank Secondary Containment - Base	26,972	28,378	29,241	29,187	29,133	29,080	29,026	28,971	28,917	28,863	28,809	28,756	345,333
4.3	Above Ground Tank Secondary Containment - Intermediate	4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787
5	SO2/NOX Emissions Allowances - Energy	815,098	814,229	808,418	781,925	739,597	689,577	637,428	576,718	516,588	466,400	424,463	385,894	7,656,333
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	25,784	25,742	25,704	25,662	25,621	25,581	25,542	25,501	25,461	25,420	25,380	25,340	306,738
7.3	CAMR Crystal River - Base	3,165	3,172	3,179	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,137
7.4	CAIR/CAMR Crystal River AFUDC - Base	327,095	335,936	329,460	325,670	351,772	1,056,879	2,196,867	2,666,418	2,664,403	2,659,866	2,655,200	8,463,717	24,033,283
7.4	CAIR/CAMR Crystal River AFUDC - Energy	0	0	0	0	0	0	870	1,740	3,307	6,442	8,010	8,010	28,378
9	Sea Turtle - Coastal Street Lighting -Distribution	156	156	155	155	155	153	172	208	271	326	362	424	2,692
10.1	Underground Storage Tanks-Base	2,370	2,366	2,360	2,355	2,350	2,344	2,340	2,335	2,330	2,325	2,320	2,315	28,108
10.2	Underground Storage Tanks-Intermediate	1,043	1,041	1,038	1,036	1,034	1,032	1,029	1,027	1,025	1,023	1,021	1,018	12,366
11	Modular Cooling Towers - Base	15,357	15,235	15,113	14,991	14,869	14,747	14,625	14,503	14,381	14,259	14,137	14,016	176,235
11.1	Thermal Discharge Permanent Cooling Tower - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	1,368,654	1,381,697	1,371,850	1,342,892	1,332,269	1,991,145	3,080,640	3,491,555	3,432,299	3,380,756	3,337,065	9,108,770	**34,619,592**
3	Recoverable Costs Allocated to Energy	815,098	814,229	808,418	781,925	739,597	689,577	638,298	578,455	519,895	472,842	432,473	393,904	7,684,711
	Recoverable Costs Allocated to Demand - Distribution	156	156	155	155	155	153	172	208	271	326	362	424	2,692
4	Recoverable Costs Allocated to Demand - Production - Base	374,959	385,087	379,353	375,383	401,304	1,106,230	2,246,038	2,715,407	2,713,211	2,708,493	2,703,646	8,511,983	24,621,097
	Recoverable Costs Allocated to Demand - Production - Intermediate	53,800	53,414	53,723	53,840	53,843	53,698	53,551	53,406	53,261	53,117	52,971	52,824	641,447
	Recoverable Costs Allocated to Demand - Production - Peaking	124,641	128,811	130,201	131,589	137,370	141,488	142,581	144,078	145,660	145,978	147,614	149,634	1,669,645
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95890	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
6	Retail Demand Jurisdictional Factor - Production - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
7	Jurisdictional Energy Recoverable Costs (B)	788,852	783,451	781,174	755,731	715,782	668,614	612,957	554,102	497,800	452,131	413,401	378,108	7,402,104
	Jurisdictional Demand Recoverable Costs - Distribution (B)	155	156	154	154	154	152	171	207	270	325	360	423	2,681
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	351,535	361,031	355,655	351,933	376,235	1,037,124	2,105,728	2,545,776	2,543,717	2,539,294	2,534,749	7,980,240	23,083,017
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	42,527	42,221	42,466	42,558	42,561	42,446	42,330	42,215	42,101	41,987	41,871	41,756	507,039
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	110,904	114,615	115,852	117,087	122,230	125,895	126,867	128,199	129,607	129,890	131,345	133,143	1,485,633
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,293,974	$1,301,474	$1,295,301	$1,267,463	$1,256,962	$1,874,230	$2,888,054	$3,270,500	$3,213,494	$3,163,626	$3,121,727	$8,533,669	$32,480,473

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

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			($187,531)	$82,276	$0	$27,105	$0	$0	$0	$0	$0	$0	$0	$0	($78,151)
	b. Clearings to Plant			(187,531)	82,276	0	27,105	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		$3,657,886	3,470,355	3,552,631	3,552,631	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	
3	Less: Accumulated Depreciation		(419,544)	(431,372)	(443,481)	(455,590)	(467,792)	(479,994)	(492,196)	(504,398)	(516,600)	(528,802)	(541,004)	(553,206)	(565,408)	
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)		3,238,343	3,038,983	3,109,150	3,097,041	3,111,944	3,099,742	3,087,540	3,075,338	3,063,136	3,050,934	3,038,732	3,026,530	3,014,328	
6	Average Net Investment			3,138,663	3,074,067	3,103,096	3,104,492	3,105,843	3,093,641	3,081,439	3,069,237	3,057,035	3,044,833	3,032,631	3,020,429	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		29,189	28,588	28,858	28,873	28,885	28,771	28,657	28,544	28,430	28,317	28,203	28,090	343,405
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		5,336	5,226	5,276	5,278	5,279	5,259	5,239	5,217	5,197	5,177	5,156	5,134	62,774
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Investment Expenses															
	a. Depreciation (C)			11,828	12,109	12,109	12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	145,864
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	-
	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)			2,372	2,428	2,428	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	29,251
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)			48,725	48,351	48,671	48,800	48,813	48,679	48,545	48,410	48,276	48,143	48,008	47,873	581,294
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	-
	b. Recoverable Costs Allocated to Demand			48,725	48,351	48,671	48,800	48,813	48,679	48,545	48,410	48,276	48,143	48,008	47,873	581,294
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	N/A
11	Demand Jurisdictional Factor - Production (Intermediate)			0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046
12	Retail Energy-Related Recoverable Costs (E)			-	-	-	-	-	-	-	-	-	-	-	-	0
13	Retail Demand-Related Recoverable Costs (F)			38,515	38,220	38,472	38,574	38,585	38,479	38,373	38,266	38,160	38,055	37,948	37,842	459,490
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$38,515	$38,220	$38,472	$38,574	$38,585	$38,479	$38,373	$38,266	$38,160	$38,055	$37,948	$37,842	$459,490

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Lines 2 x 89% @ .008313 x 1/12 + 11%@ .007299 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2008 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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$625,159	$161,761	$118,706	$166,669	$40,105	$90,116	$10,005	$310,000	$25,000	$80,000	$265,000	$150,000	$2,042,521
	b. Clearings to Plant			5,180	9,882	11,146	1,682	2,934,831	344,696	5	-	-	-	-	-	
	c. Retirements			-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other (A)			-	-	-	-	(18,099)	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base		$5,267,973	5,273,153	5,283,034	5,294,181	5,295,863	8,230,694	8,575,390	8,575,395	8,575,395	8,575,395	8,575,395	8,575,395	8,575,395	
3	Less: Accumulated Depreciation		(278,408)	(289,476)	(302,564)	(315,674)	(328,787)	(344,574)	(363,834)	(383,892)	(403,950)	(424,008)	(444,066)	(464,124)	(484,182)	
4	CWIP - Non-Interest Bearing		2,158,040	2,778,019	2,929,899	3,037,458	3,202,445	289,620	35,039	45,039	355,039	380,039	460,039	725,039	875,039	
5	Net Investment (Lines 2 + 3 + 4)		7,149,605	7,761,696	7,910,369	8,015,965	8,169,521	8,175,740	8,246,595	8,236,542	8,526,484	8,531,426	8,591,368	8,836,310	8,966,252	
6	Average Net Investment			7,455,651	7,836,033	7,963,167	8,092,743	8,172,630	8,211,167	8,241,568	8,381,513	8,528,955	8,561,397	8,713,839	8,901,281	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		69,337	72,876	74,058	75,263	76,006	76,364	76,647	77,948	79,318	79,622	81,038	82,781	921,258
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		12,676	13,321	13,537	13,757	13,894	13,959	14,010	14,247	14,499	14,554	14,814	15,131	168,399
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Investment Expenses															
	a. Depreciation (C)			13,068	13,088	13,110	13,113	15,787	19,260	20,058	20,058	20,058	20,058	20,058	20,058	207,774
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	-
	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)			3,776	3,784	3,792	3,794	6,061	6,324	6,324	6,324	6,324	6,324	6,324	6,324	65,475
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)			98,857	103,069	104,497	105,927	111,749	115,907	117,039	118,577	120,199	120,558	122,234	124,294	1,362,907
	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			98,857	103,069	104,497	105,927	111,749	115,907	117,039	118,577	120,199	120,558	122,234	124,294	1,362,907
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 (Peaking)			0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
12	Retail Energy-Related Recoverable Costs (E)			-	-	-	-	-	-	-	-	-	-	-	-	0
13	Retail Demand-Related Recoverable Costs (F)			87,962	91,710	92,980	94,253	99,433	103,133	104,140	105,509	106,952	107,271	108,763	110,596	1,212,701
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$87,962	$91,710	$92,980	$94,253	$99,433	$103,133	$104,140	$105,509	$106,952	$107,271	$108,763	$110,596	$1,212,701

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-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 2008 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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$166,822	$34	$0	$0	$0	$0	$0	$0	$0	$0	$0	$166,856
	b. Clearings to Plant			-	166,822	34	-	-	-	-	-	-	-	-	-	
	c. Retirements			-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other (A)			-	-	-	-	-	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base		$1,901,933	1,901,933	2,068,756	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	
3	Less: Accumulated Depreciation		(9,419)	(13,937)	(18,849)	(23,761)	(28,673)	(33,585)	(38,497)	(43,409)	(48,321)	(53,233)	(58,145)	(63,057)	(67,969)	
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)		1,892,515	1,887,997	2,049,907	2,045,029	2,040,117	2,035,205	2,030,293	2,025,381	2,020,469	2,015,557	2,010,645	2,005,733	2,000,821	
6	Average Net Investment			1,890,256	1,968,952	2,047,468	2,042,573	2,037,661	2,032,749	2,027,837	2,022,925	2,018,013	2,013,101	2,008,189	2,003,277	24,113,004
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,579	18,311	19,041	18,996	18,950	18,905	18,859	18,813	18,768	18,722	18,676	18,631	224,251
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,214	3,348	3,481	3,472	3,464	3,456	3,448	3,439	3,430	3,422	3,414	3,406	40,994
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	0
8	Investment Expenses															
	a. Depreciation (C)			4,518	4,912	4,912	4,912	4,912	4,912	4,912	4,912	4,912	4,912	4,912	4,912	58,550
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	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)			1,661	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	21,538
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	0
9	Total System Recoverable Expenses (Lines 7 + 8)			26,972	28,378	29,241	29,187	29,133	29,080	29,026	28,971	28,917	28,863	28,809	28,756	345,333
	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			26,972	28,378	29,241	29,187	29,133	29,080	29,026	28,971	28,917	28,863	28,809	28,756	345,333
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
12	Retail Energy-Related Recoverable Costs (E)			-	-	-	-	-	-	-	-	-	-	-	-	0
13	Retail Demand-Related Recoverable Costs (F)			25,287	26,605	27,414	27,364	27,313	27,263	27,213	27,161	27,111	27,060	27,009	26,960	323,760
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$25,287	$26,605	$27,414	$27,364	$27,313	$27,263	$27,213	$27,161	$27,111	$27,060	$27,009	$26,960	$323,760

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-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 2008 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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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		-	-	-	-	-	-	-	-	-	-	-	-	
	c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other (A)		-	-	-	-	-	-	-	-	-	-	-	-	
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	(12,522)	(13,330)	(14,138)	(14,946)	(15,754)	(16,562)	(17,370)	(18,178)	(18,986)	(19,794)	(20,602)	(21,410)	(22,218)	
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)	277,776	276,968	276,160	275,352	274,544	273,736	272,928	272,120	271,312	270,504	269,696	268,888	268,080	
6	Average Net Investment		277,372	276,564	275,756	274,948	274,140	273,332	272,524	271,716	270,908	270,100	269,292	268,484	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		2,580	2,572	2,565	2,557	2,550	2,542	2,534	2,527	2,519	2,512	2,504	2,497	30,459
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		472	470	469	467	466	465	463	462	461	459	458	456	5,568
	c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
8	Investment Expenses														
	a. Depreciation (C)		808	808	808	808	808	808	808	808	808	808	808	808	9,696
	b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	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)		172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other		-	0	0	0	0	0		0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787
	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		4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		3,187	3,179	3,173	3,165	3,159	3,152	3,144	3,137	3,130	3,123	3,116	3,109	37,774
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$3,187	$3,179	$3,173	$3,165	$3,159	$3,152	$3,144	$3,137	$3,130	$3,123	$3,116	$3,109	$37,774

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-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 2008 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 2009 through December 2009

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$11,191,196	$10,756,806	$10,416,782	$10,103,171	$9,810,743	$9,478,854	$9,110,149	$8,722,409	$8,277,816	$7,857,535	$7,461,599	$7,162,229	$6,902,143	$6,902,143
	b. 25401FL Auctioned SO_2 Allowance		(2,063,254)	(2,051,459)	(2,039,664)	(2,027,869)	(2,016,074)	(2,085,825)	(2,062,381)	(2,038,936)	(2,015,491)	(1,992,047)	(1,968,602)	(1,945,158)	(1,921,713)	(1,921,713)
	c. 1581002 NOX Emission Allowance Inventory		65,510,820	64,855,450	66,103,726	64,429,120	61,869,163	57,415,302	53,521,483	$48,643,241	$43,268,337	$38,528,993	$34,912,474	$31,552,600	$28,412,468	28,412,468
2	Total Working Capital		$74,638,763	73,560,797	74,480,844	72,504,423	69,663,832	64,808,331	60,569,251	55,326,714	49,530,662	44,394,481	40,405,470	36,769,671	33,392,897	33,392,897
3	Average Net Investment			74,099,780	74,020,821	73,492,634	71,084,127	67,236,081	62,688,791	57,947,983	52,428,688	46,962,572	42,399,976	38,587,570	35,081,284	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		689,128	688,394	683,481	661,082	625,296	583,006	538,916	487,587	436,752	394,320	358,864	326,256	$6,473,082
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		125,970	125,835	124,937	120,843	114,301	106,571	98,512	89,129	79,836	72,080	65,599	59,638	1,183,252
5	Total Return Component (B)			815,098	814,229	808,419	781,925	739,597	689,577	637,428	576,716	516,588	466,400	424,463	385,894	7,656,333
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			434,390	340,024	313,610	292,429	331,889	368,705	$387,741	$444,592	$420,281	$395,937	$299,370	$260,086	4,289,054
	b. 4074004 Amortization Expense			($11,795)	($11,795)	($11,795)	($11,795)	($61,868)	($23,445)	($23,445)	($23,445)	($23,445)	($23,445)	($23,445)	($23,445)	($273,159)
	c. 5090003 NOx Allowance Expense			$3,994,120	3,668,223	3,246,107	2,889,957	4,455,861	5,252,069	$4,878,241	$5,374,904	$4,739,344	$3,616,519	$3,359,874	$3,140,132	$48,615,352
	d. Other			$0	0	0	0	0	6,250	$0	$0	$0	$0	$0	$0	$6,250
7	Net Expense (C)			4,416,716	3,996,452	3,547,922	3,170,590	4,725,882	5,603,579	5,242,537	5,796,052	5,136,181	3,989,011	3,635,800	3,376,773	52,637,496
8	Total System Recoverable Expenses (Lines 5 + 7)			5,231,813	4,810,681	4,356,341	3,952,516	5,465,479	6,293,156	5,879,965	6,372,768	5,652,769	4,455,411	4,060,263	3,762,667	60,293,830
	a. Recoverable costs allocated to Energy			5,231,813	4,810,681	4,356,341	3,952,516	5,465,479	6,293,156	5,879,965	6,372,768	5,652,769	4,455,411	4,060,263	3,762,667	60,293,830
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
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)			5,063,349	4,628,838	4,209,533	3,820,106	5,289,491	6,101,844	5,646,530	6,104,474	5,412,526	4,260,264	3,881,205	3,611,784	58,029,945
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)			$ 5,063,349	$ 4,628,838	$ 4,209,533	$ 3,820,106	$ 5,289,491	$ 6,101,844	$ 5,646,530	$ 6,104,474	$ 5,412,526	$ 4,260,264	$ 3,881,205	$ 3,611,784	$ 58,029,945

Notes:
(A) Lines 3 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 Rate Case Settlement in Dkt. 050078-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 Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		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) 2.21%		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) 0.007299		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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2008 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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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		$1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	
3	Less: Accumulated Depreciation		(47,164)	(50,819)	(54,474)	(58,129)	(61,784)	(65,439)	(69,094)	(72,749)	(76,404)	(80,059)	(83,714)	(87,369)	(91,024)	
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)		$1,887,236	1,883,582	1,879,927	1,876,272	1,872,617	1,868,962	1,865,307	1,861,652	1,857,997	1,854,342	1,850,687	1,847,032	1,843,377	
6	Average Net Investment			1,885,409	1,881,754	1,878,099	1,874,444	1,870,789	1,867,134	1,863,479	1,859,824	1,856,169	1,852,514	1,848,859	1,845,204	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,535	17,500	17,467	17,433	17,397	17,364	17,331	17,296	17,262	17,228	17,194	17,161	208,168
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,206	3,199	3,194	3,186	3,181	3,174	3,168	3,162	3,156	3,149	3,143	3,136	38,054
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	0
8	Investment Expenses															
	a. Depreciation (C)			3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	43,860
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	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)			1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	16,656
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	0
9	Total System Recoverable Expenses (Lines 7 + 8)			25,784	25,742	25,704	25,662	25,621	25,581	25,542	25,501	25,461	25,420	25,380	25,340	306,738
	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			25,784	25,742	25,704	25,662	25,621	25,581	25,542	25,501	25,461	25,420	25,380	25,340	306,738
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	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)			22,942	22,905	22,871	22,834	22,797	22,762	22,727	22,691	22,655	22,618	22,583	22,547	272,932
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$22,942	$22,905	$22,871	$22,834	$22,797	$22,762	$22,727	$22,691	$22,655	$22,618	$22,583	$22,547	$272,932

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-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 2008 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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$243	$1,094	$200	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,538
	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		287,569	287,812	288,907	289,106	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)		$287,569	287,812	288,907	289,106	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
6	Average Net Investment			287,691	288,360	289,007	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,676	2,682	2,688	2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	$32,243
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		489	490	491	491	491	491	491	491	491	491	491	491	5,894
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.19%		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)	0.010707		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)			3,165	3,172	3,179	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,137
	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			3,165	3,172	3,179	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,137
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			2,967	2,974	2,980	2,982	2,982	2,982	2,982	2,982	2,982	2,982	2,982	2,982	35,755
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,967	$2,974	$2,980	$2,982	$2,982	$2,982	$2,982	$2,982	$2,982	$2,982	$2,982	$2,982	$35,755

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$26,212,349	$27,108,153	$23,020,640	$22,851,091	$16,544,690	$17,360,816	14,749,560	15,480,095	8,538,220	12,931,151	15,519,896	15,456,092	$215,772,754
	b. Clearings to Plant			1,596,194	82,031	(672,773)	64,021	3,030,400	91,324,148	70,480,087	465,714	44,167	20,833	20,833	769,456,210	
	c. Retirements			-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other (A)	8.848%		5,541,202	5,796,238	6,022,014	6,242,666	6,438,213	6,127,257	6,091,140	6,227,289	6,332,845	6,406,644	6,483,057	1,372,262	69,080,828
2	Plant-in-Service/Depreciation Base		$21,762,083	23,358,277	23,440,309	22,767,536	22,831,557	25,861,957	117,186,105	187,666,192	188,131,906	188,176,073	188,196,906	188,217,739	957,673,949	
3	Less: Accumulated Depreciation		(341,009)	(403,639)	(466,498)	(527,397)	(588,470)	(656,690)	(832,656)	(1,200,122)	(1,651,029)	(2,102,040)	(2,553,100)	(3,004,209)	(4,362,660)	
4	CWIP - AFUDC-Interest Bearing		869,261,457	899,418,815	932,241,174	961,956,601	990,986,337	1,010,938,840	943,102,765	893,463,378	914,705,048	929,531,946	948,848,908	970,831,029	218,203,174	284,853,582
5	Net Investment (Lines 2 + 3 + 4)		890,682,532	922,373,453	955,214,985	984,196,740	1,013,229,424	1,036,144,107	1,059,456,215	1,079,929,448	1,101,185,925	1,115,605,979	1,134,492,714	1,156,044,559	1,171,514,463	
6	Average Net Investment			906,527,992	938,794,219	969,705,862	998,713,082	1,024,686,766	1,047,800,161	1,069,692,831	1,090,557,687	1,108,395,952	1,125,049,347	1,145,268,637	1,163,779,511	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		206,347	213,567	210,245	206,847	220,635	658,247	1,408,110	1,734,203	1,732,380	1,728,487	1,724,486	5,298,455	15,342,009
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		37,719	39,039	38,432	37,811	40,331	120,324	257,396	317,006	316,672	315,961	315,228	968,535	2,804,454
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Investment Expenses															
	a. Depreciation (C)			62,630	62,859	60,899	61,073	68,220	175,966	367,466	450,907	451,011	451,060	451,109	1,359,546	4,022,746
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	-
	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)			20,399	20,471	19,884	19,939	22,586	102,342	163,895	164,302	164,340	164,358	164,377	837,181	1,864,074
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)			327,095	335,936	329,460	325,670	351,772	1,056,879	2,196,867	2,666,418	2,664,403	2,659,866	2,655,200	8,463,717	24,033,283
	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			327,095	335,936	329,460	325,670	351,772	1,056,879	2,196,867	2,666,418	2,664,403	2,659,866	2,655,200	8,463,717	24,033,283
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
12	Retail Energy-Related Recoverable Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs			306,661	314,950	308,879	305,325	329,797	990,856	2,059,629	2,499,847	2,497,958	2,493,704	2,489,330	7,934,989	22,531,924
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$306,661	$314,950	$308,879	$305,325	$329,797	$990,856	$2,059,629	$2,499,847	$2,497,958	$2,493,704	$2,489,330	$7,934,989	$22,531,924

Notes:
(A) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(B) Return on equity and debt calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 6 x rate x 1/12. Rate based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Depreciation calculated only on assets placed inservice which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property taxes calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1544001 Ammonia Inventory		$0	$0	$0	$0	$0	$0	$0	$158,148	$158,148	$158,148	$158,148	$158,148	$158,148	$158,148
	b. 1544004 Limestone Inventory		0	0	0	0	0	0	0	0	0	285,000	570,000	570,000	570,000	570,000
2	Total Working Capital		$0	0	0	0	0	0	0	158,148	158,148	443,148	728,148	728,148	728,148	728,148
3	Average Net Investment			0	0	0	0	0	0	79,074	158,148	300,648	585,648	728,148	728,148	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		0	0	0	0	0	0	735	1,471	2,796	5,447	6,772	6,772	$23,992
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	134	269	511	996	1,238	1,238	4,386
5	Total Return Component (B)			0	0	0	0	0	0	870	1,740	3,307	6,442	8,010	8,010	28,378
6	Expense Dr (Cr)															
	a. 5020011 Ammonia expense			0	0	0	0	0	0	221,096	241,714	237,897	255,057	16,481	227,374	1,199,619
	c. 5020012 Limestone Expense			0	0	0	0	0	0	0	0	0	0	0	48,296	48,296
	d. 5020003 Gypsum Disposal/Sale			0	0	0		0	0	0	0	0	0	0	139,505	139,505
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			0	0	0	0	0	0	221,096	241,714	237,897	255,057	16,481	415,175	1,387,420
8	Total System Recoverable Expenses (Lines 5 + 7)			0	0	0	0	0	0	221,966	243,454	241,204	261,499	24,491	423,185	1,415,798
	a. Recoverable costs allocated to Energy			0	0	0	0	0	0	221,966	243,454	241,204	261,499	24,491	423,185	1,415,798
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			0	0	0	0	0	0	208,099	228,245	226,136	245,163	22,961	396,749	1,327,353
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)			$ -	$ -	$ -	$ -	$ -	$ -	$ 208,099	$ 228,245	$ 226,136	$ 245,163	$ 22,961	$ 396,749	$ 1,327,353

Notes:
(A) Lines 3 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 Rate Case Settlement in Dkt. 050078-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 Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$3,333	$3,333	$3,333	$3,333	$3,333	$3,333	$20,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	10,000	-	-	10,000	
	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	$10,146	10,146	10,146	10,146	10,146	10,146	10,146	10,146	10,146	20,146	20,146	20,146	30,146	
3	Less: Accumulated Depreciation	(232)	(271)	(310)	(349)	(388)	(427)	(466)	(505)	(544)	(602)	(679)	(756)	(852)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	3,333	6,667	0	3,333	6,667	0	
5	Net Investment (Lines 2 + 3 + 4)	$9,914	9,875	9,836	9,797	9,758	9,719	9,680	12,974	16,269	19,544	22,800	26,057	29,294	
6	Average Net Investment		9,895	9,856	9,817	9,778	9,739	9,700	11,327	14,622	17,906	21,172	24,429	27,675	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		92	92	91	91	91	90	105	136	167	197	227	257	$1,636
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		17	17	17	17	17	16	19	25	30	36	42	47	299
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 4.59%		39	39	39	39	39	39	39	39	58	77	77	96	620
	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) 0.009400		8	8	8	8	8	8	8	8	8	16	16	24	136
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		156	155	155	155	154	154	172	208	271	326	362	424	2,691
	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		156	155	155	155	154	154	172	208	271	326	362	424	2,691
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)		0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
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)		155	155	154	154	154	153	171	207	270	325	360	423	2,680
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$155	$155	$154	$154	$154	$153	$171	$207	$270	$325	$360	$423	$2,680

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2008 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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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	(8,512)	(8,972)	(9,432)	(9,892)	(10,352)	(10,812)	(11,272)	(11,732)	(12,192)	(12,652)	(13,112)	(13,572)	(14,032)	
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)	$160,429	159,969	159,509	159,049	158,589	158,129	157,669	157,209	156,749	156,289	155,829	155,369	154,909	
6	Average Net Investment		160,199	159,739	159,279	158,819	158,359	157,899	157,439	156,979	156,519	156,059	155,599	155,139	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		1,490	1,486	1,481	1,477	1,473	1,468	1,464	1,460	1,456	1,451	1,447	1,443	$17,596
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		272	272	271	270	269	268	268	267	266	265	265	264	3,216
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.27%		460	460	460	460	460	460	460	460	460	460	460	460	5,520
	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) 0.010480		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)		2,370	2,365	2,360	2,355	2,350	2,345	2,340	2,335	2,330	2,325	2,320	2,315	28,108
	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		2,370	2,365	2,360	2,355	2,350	2,345	2,340	2,335	2,330	2,325	2,320	2,315	28,108
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)		0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)		2,222	2,217	2,213	2,208	2,203	2,198	2,194	2,189	2,184	2,179	2,175	2,170	26,352
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,222	$2,217	$2,213	$2,208	$2,203	$2,198	$2,194	$2,189	$2,184	$2,179	$2,175	$2,170	$26,352

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-1)
Page 20 of 24

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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	(4,745)	(4,947)	(5,149)	(5,351)	(5,553)	(5,755)	(5,957)	(6,159)	(6,361)	(6,563)	(6,765)	(6,967)	(7,169)	
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)	$71,261	71,059	70,857	70,655	70,453	70,251	70,049	69,847	69,645	69,443	69,241	69,039	68,837	
6	Average Net Investment		71,160	70,958	70,756	70,554	70,352	70,150	69,948	69,746	69,544	69,342	69,140	68,938	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		662	660	658	656	654	652	651	649	647	645	643	641	$7,817
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		121	121	120	120	120	119	119	119	118	118	118	117	1,429
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.19%		202	202	202	202	202	202	202	202	202	202	202	202	2,424
	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) 0.009130		58	58	58	58	58	58	58	58	58	58	58	58	696
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,043	1,041	1,038	1,036	1,034	1,032	1,029	1,027	1,025	1,023	1,021	1,018	12,366
	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		1,043	1,041	1,038	1,036	1,034	1,032	1,029	1,027	1,025	1,023	1,021	1,018	12,366
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		824	823	821	819	817	815	814	812	810	808	807	805	9,775
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$824	$823	$821	$819	$817	$815	$814	$812	$810	$808	$807	$805	$9,775

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2008 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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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		(324,147)	(335,233)	(346,319)	(357,405)	(368,491)	(379,577)	(390,663)	(401,749)	(412,835)	(423,921)	(435,007)	(446,093)	(457,179)	
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)		$340,994	329,908	318,822	307,736	296,650	285,564	274,478	263,392	252,306	241,220	230,134	219,048	207,962	
6	Average Net Investment			335,451	324,365	313,279	302,193	291,107	280,021	268,935	257,849	246,763	235,677	224,591	213,505	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		3,120	3,017	2,913	2,810	2,707	2,604	2,501	2,398	2,295	2,192	2,089	1,986	$30,632
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		570	551	533	514	495	476	457	438	419	401	382	363	5,599
	c. Other (G)			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	11,086	11,086	11,086	11,086	11,086	11,086	133,032
	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)	0.010480		581	581	581	581	581	581	581	581	581	581	581	581	6,972
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			15,357	15,235	15,113	14,991	14,869	14,747	14,625	14,503	14,381	14,259	14,137	14,016	176,235
	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			15,357	15,235	15,113	14,991	14,869	14,747	14,625	14,503	14,381	14,259	14,137	14,016	176,235
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			14,398	14,283	14,169	14,055	13,940	13,826	13,712	13,597	13,483	13,369	13,254	13,140	165,226
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$14,398	$14,283	$14,169	$14,055	$13,940	$13,826	$13,712	$13,597	$13,483	$13,369	$13,254	$13,140	$165,226

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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 2008 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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$10,944	$5,686	$116,839	$801,002	$118,007	$348,477	$2,846,056	$2,460,588	$1,023,529	$693,288	$133,548	$601,224	$9,159,188
	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	2,742	6,155	10,645	16,140	27,967	46,978	59,662	66,171	69,571	72,669	378,700
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	10,944	16,630	136,212	943,369	1,072,021	1,436,638	4,310,661	6,818,226	7,901,417	8,660,876	8,863,995	9,537,888	
5	Net Investment (Lines 2 + 3 + 4)		$0	10,944	16,630	136,212	943,369	1,072,021	1,436,638	4,310,661	6,818,226	7,901,417	8,660,876	8,863,995	9,537,888	
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 Grossed Up For Taxes (B)	11.16%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other (G)			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)	0.010480		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 (Base)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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 calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-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 2008 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 2009 through December 2009

Variance Report of Capital Investment Activities
(In Dollars)

Line		(1) Estimated/ Actual	(2) Original Projection	(3) Variance Amount	(4) Percent
1	Description of Investment Projects				
3	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	($78,151)	$60,000	($138,151)	-230%
4.1	Above Ground Tank Secondary Containment - Peaking	2,042,521	1,337,000	705,521	53%
4.2	Above Ground Tank Secondary Containment - Base	166,856	-	166,856	100%
4.3	Above Ground Tank Secondary Containment - Intermediate	-	-	-	
5	SO2/NOX Emissions Allowances - Energy (A)	33,392,897	32,394,756	998,142	3%
7.1	CAIR/CAMR Anclote- Intermediate	-	-	-	N/A
7.2	CAIR CT's - Peaking	-	-	-	N/A
7.3	CAMR Crystal River - Base	1,538	-	1,538	100%
7.4	CAIR/CAMR Crystal River AFUDC - Base	215,772,754	$215,895,835	(123,081)	0%
9	Sea Turtle - Coastal Street Lighting -Distribution	20,000	20,000	-	0%
10.1	Underground Storage Tanks-Base	-	-	-	N/A
10.2	Underground Storage Tanks-Intermediate	-	-	-	N/A
11	Modular Cooling Towers - Base	-	-	-	N/A
11.1	Thermal Discharge Permanent Cooling Tower - Base	9,159,188	$11,599,807	(2,440,619)	-21%
2	Total Investment Projects - Capital Expenditures	260,477,603	261,307,397	(829,794)	0%

Notes:
(A) Working Capital

Witness: T.G. Foster
Exibit__(TGF-2)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2009 - DECEMBER 2009

DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 25
COMPANY Progress Energy Florida, Inc.
WITNESS Thomas G. Foster (TGF-2)
DATE 11/02/09

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		(4,453)	(4,540)	(4,627)	(4,714)	(4,801)	(4,888)	(4,975)	(5,062)	(5,149)	(5,236)	(5,323)	(5,410)	(5,497)	
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)		$29,500	29,413	29,326	29,239	29,152	29,065	28,978	28,891	28,804	28,717	28,630	28,543	28,456	
6	*Average Net Investment*			*29,456*	*29,369*	*29,282*	*29,195*	*29,108*	*29,021*	*28,934*	*28,847*	*28,760*	*28,673*	*28,586*	*28,499*	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		274	273	272	272	271	270	269	268	267	267	266	265	$3,234
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		*50*	*50*	*50*	*50*	*49*	*49*	*49*	*49*	*49*	*49*	*49*	*48*	*591*
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.07%		87	87	87	87	87	87	87	87	87	87	87	87	1,044
	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	0.008201		23	23	23	23	23	23	23	23	23	23	23	23	276
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			434	433	432	432	430	429	428	427	426	426	425	423	5,145
	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			434	433	432	432	430	429	428	427	426	426	425	423	5,145

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		(413,411)	(422,433)	(431,455)	(440,477)	(449,499)	(458,521)	(467,543)	(476,565)	(485,587)	(494,609)	(503,631)	(512,653)	(521,675)	
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)		$2,227,225	2,218,203	2,209,181	2,200,159	2,191,137	2,182,115	2,173,093	2,164,071	2,155,049	2,146,027	2,137,005	2,127,983	2,118,961	
6	*Average Net Investment*			*2,222,714*	*2,213,692*	*2,204,670*	*2,195,648*	*2,186,626*	*2,177,604*	*2,168,582*	*2,159,560*	*2,150,538*	*2,141,516*	*2,132,494*	*2,123,472*	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		20,671	20,587	20,503	20,420	20,336	20,252	20,168	20,084	20,000	19,916	19,832	19,748	$242,517
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,779	3,763	3,748	3,733	3,717	3,702	3,687	3,671	3,656	3,641	3,625	3,610	44,332
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	*Investment Expenses*															
	a. Depreciation	4.10%		9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	108,264
	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	0.008201		1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	21,660
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			35,277	35,177	35,078	34,980	34,880	34,781	34,682	34,582	34,483	34,384	34,284	34,185	416,773
	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			35,277	35,177	35,078	34,980	34,880	34,781	34,682	34,582	34,483	34,384	34,284	34,185	416,773

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		($187,531)	$82,276	$0	$27,105	$0	$0	$0	$0	$0	$0	$0	$0	($78,151)
	b. Clearings to Plant		(187,531)	82,276	0	27,105	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	$983,298	795,767	878,043	878,043	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	
3	Less: Accumulated Depreciation	(1,680)	(4,399)	(7,399)	(10,399)	(13,492)	(16,585)	(19,678)	(22,771)	(25,864)	(28,957)	(32,050)	(35,143)	(38,236)	
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)	$981,618	791,368	870,643	867,643	891,655	888,562	885,469	882,376	879,283	876,190	873,097	870,004	866,911	
6	Average Net Investment		886,493	831,005	869,143	879,649	890,109	887,016	883,923	880,830	877,737	874,644	871,551	868,458	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		8,244	7,728	8,083	8,181	8,278	8,249	8,220	8,192	8,163	8,134	8,105	8,077	$97,654
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		1,507	1,413	1,478	1,495	1,513	1,508	1,503	1,497	1,492	1,487	1,482	1,476	17,851
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 4.10%		2,719	3,000	3,000	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	36,556
	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 0.008201		544	600	600	619	619	619	619	619	619	619	619	619	7,315
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		13,014	12,741	13,161	13,388	13,503	13,469	13,435	13,401	13,367	13,333	13,299	13,265	159,376
	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		13,014	12,741	13,161	13,388	13,503	13,469	13,435	13,401	13,367	13,333	13,299	13,265	159,376

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Deatil Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$241,385	$45,946	$102,360	$34,750	$0	$190	$0	$0	$0	$0	$0	$0	$424,631
	b. Clearings to Plant			0	0	0	0	903,126	190	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	(18,099)	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,051,183	1,051,183	1,051,183	1,051,183	1,051,183	1,954,309	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	
3	Less: Accumulated Depreciation		(5,658)	(7,291)	(8,924)	(10,557)	(12,190)	(14,524)	(17,560)	(20,596)	(23,632)	(26,668)	(29,704)	(32,740)	(35,776)	
4	CWIP - Non-Interest Bearing		496,784	738,169	784,115	886,475	921,225	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,542,310	1,782,061	1,826,375	1,927,101	1,960,218	1,939,785	1,936,939	1,933,903	1,930,867	1,927,831	1,924,795	1,921,759	1,918,723	
6	Average Net Investment			1,662,186	1,804,218	1,876,738	1,943,660	1,950,002	1,938,362	1,935,421	1,932,385	1,929,349	1,926,313	1,923,277	1,920,241	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		15,458	16,779	17,454	18,076	18,135	18,027	17,999	17,971	17,943	17,915	17,886	17,858	$211,501
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		2,826	3,067	3,190	3,304	3,315	3,295	3,290	3,285	3,280	3,275	3,270	3,264	38,661
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.86%		1,633	1,633	1,633	1,633	2,335	3,036	3,036	3,036	3,036	3,036	3,036	3,036	30,119
	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	0.009270		812	812	812	812	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	15,328
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			20,729	22,291	23,089	23,825	25,295	25,868	25,835	25,802	25,769	25,736	25,702	25,668	295,609
	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			20,729	22,291	23,089	23,825	25,295	25,868	25,835	25,802	25,769	25,736	25,702	25,668	295,609

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$4,994	$4,980	$874	$3,281	$0	$3,586	$10,000	$310,000	$25,000	$80,000	$265,000	$150,000	$857,716
	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		$153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	
3	Less: Accumulated Depreciation		(30,596)	(31,020)	(31,444)	(31,868)	(32,292)	(32,716)	(33,140)	(33,564)	(33,988)	(34,412)	(34,836)	(35,260)	(35,684)	
4	CWIP - Non-Interest Bearing		17,325	22,319	27,299	28,173	31,454	31,454	35,040	45,040	355,040	380,040	460,040	725,040	875,040	
5	Net Investment (Lines 2 + 3 + 4)		$140,427	144,997	149,553	150,003	152,861	152,437	155,599	165,175	474,751	499,327	578,903	843,479	993,055	
6	Average Net Investment			142,712	147,275	149,778	151,432	152,649	154,018	160,387	319,963	487,039	539,115	711,191	918,267	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,327	1,370	1,393	1,408	1,420	1,432	1,492	2,976	4,529	5,014	6,614	8,540	$37,515
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		243	250	255	257	260	262	273	544	828	916	1,209	1,561	6,858
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.31%		424	424	424	424	424	424	424	424	424	424	424	424	5,088
	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	0.009130		117	117	117	117	117	117	117	117	117	117	117	117	1,404
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,111	2,161	2,189	2,206	2,221	2,235	2,306	4,061	5,898	6,471	8,364	10,642	50,865
	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			2,111	2,161	2,189	2,206	2,221	2,235	2,306	4,061	5,898	6,471	8,364	10,642	50,865

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Distribution Support - January 2009 through December 2009
Pipline Integrity Management (Project 3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(7,215)	(7,326)	(7,437)	(7,548)	(7,659)	(7,770)	(7,881)	(7,992)	(8,103)	(8,214)	(8,325)	(8,436)	(8,547)	
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)	$25,877	25,766	25,655	25,544	25,433	25,322	25,211	25,100	24,989	24,878	24,767	24,656	24,545	
6	Average Net Investment		25,821	25,710	25,599	25,488	25,377	25,266	25,155	25,044	24,933	24,822	24,711	24,600	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		240	239	238	237	236	235	234	233	232	231	230	229	$2,814
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		44	44	44	43	43	43	43	43	42	42	42	42	515
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,332
	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 0.010480		29	29	29	29	29	29	29	29	29	29	29	29	348
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		424	423	422	420	419	418	417	416	414	413	412	411	5,009
	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		424	423	422	420	419	418	417	416	414	413	412	411	5,009

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(119,795)	(124,489)	(129,183)	(133,877)	(138,571)	(143,265)	(147,959)	(152,653)	(157,347)	(162,041)	(166,735)	(171,429)	(176,123)	
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)	$1,541,869	1,537,175	1,532,481	1,527,787	1,523,093	1,518,399	1,513,705	1,509,011	1,504,317	1,499,623	1,494,929	1,490,235	1,485,541	
6	Average Net Investment		1,539,522	1,534,828	1,530,134	1,525,440	1,520,746	1,516,052	1,511,358	1,506,664	1,501,970	1,497,276	1,492,582	1,487,888	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		14,318	14,274	14,230	14,187	14,143	14,099	14,056	14,012	13,968	13,925	13,881	13,837	$168,930
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		2,617	2,609	2,601	2,593	2,585	2,577	2,569	2,561	2,553	2,545	2,537	2,529	30,876
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 3.39%		4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	56,328
	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 0.007740		1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	12,864
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		22,701	22,649	22,597	22,546	22,494	22,442	22,391	22,339	22,287	22,236	22,184	22,132	268,998
	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		22,701	22,649	22,597	22,546	22,494	22,442	22,391	22,339	22,287	22,236	22,184	22,132	268,998

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(14,921)	(15,441)	(15,961)	(16,481)	(17,001)	(17,521)	(18,041)	(18,561)	(19,081)	(19,601)	(20,121)	(20,641)	(21,161)	
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)	$164,017	163,497	162,977	162,457	161,937	161,417	160,897	160,377	159,857	159,337	158,817	158,297	157,777	
6	Average Net Investment		163,757	163,237	162,717	162,197	161,677	161,157	160,637	160,117	159,597	159,077	158,557	158,037	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	1,523	1,518	1,513	1,508	1,504	1,499	1,494	1,489	1,484	1,479	1,475	1,470	$17,956
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%	278	278	277	276	275	274	273	272	271	270	270	269	3,283
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	3.49%	520	520	520	520	520	520	520	520	520	520	520	520	6,240
	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	0.008760	131	131	131	131	131	131	131	131	131	131	131	131	1,572
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,452	2,447	2,441	2,435	2,430	2,424	2,418	2,412	2,406	2,400	2,396	2,390	29,051
	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		2,452	2,447	2,441	2,435	2,430	2,424	2,418	2,412	2,406	2,400	2,396	2,390	29,051

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(285)	0	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*	$730,580	730,580	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	(26,168)	(27,787)	(29,406)	(31,025)	(32,644)	(34,263)	(35,882)	(37,501)	(39,120)	(40,739)	(42,358)	(43,977)	(45,596)	
4	CWIP - Non-Interest Bearing	(285)	(285)	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$704,127	702,508	700,889	699,270	697,651	696,032	694,413	692,794	691,175	689,556	687,937	686,318	684,699	
6	Average Net Investment		703,318	701,699	700,080	698,461	696,842	695,223	693,604	691,985	690,366	688,747	687,128	685,509	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	6,541	6,526	6,511	6,496	6,481	6,466	6,451	6,435	6,420	6,405	6,390	6,375	$77,497
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%	1,196	1,193	1,190	1,187	1,185	1,182	1,179	1,176	1,174	1,171	1,168	1,165	14,166
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	2.66%	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	19,428
	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	0.009130	556	556	556	556	556	556	556	556	556	556	556	556	6,672
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		9,912	9,894	9,876	9,858	9,841	9,823	9,805	9,786	9,769	9,751	9,733	9,715	117,763
	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		9,912	9,894	9,876	9,858	9,841	9,823	9,805	9,786	9,769	9,751	9,733	9,715	117,763

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(51,168)	(53,934)	(56,700)	(59,466)	(62,232)	(64,998)	(67,764)	(70,530)	(73,296)	(76,062)	(78,828)	(81,594)	(84,360)	
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)	$986,031	983,265	980,499	977,733	974,967	972,201	969,435	966,669	963,903	961,137	958,371	955,605	952,839	
6	Average Net Investment		984,648	981,882	979,116	976,350	973,584	970,818	968,052	965,286	962,520	959,754	956,988	954,222	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		9,157	9,132	9,106	9,080	9,054	9,029	9,003	8,977	8,951	8,926	8,900	8,874	$108,189
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,674	1,669	1,664	1,660	1,655	1,650	1,646	1,641	1,636	1,632	1,627	1,622	19,776
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 3.20%		2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	33,192
	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 0.007850		679	679	679	679	679	679	679	679	679	679	679	679	8,148
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,276	14,246	14,215	14,185	14,154	14,124	14,094	14,063	14,032	14,003	13,972	13,941	169,305
	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		14,276	14,246	14,215	14,185	14,154	14,124	14,094	14,063	14,032	14,003	13,972	13,941	169,305

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$378,780	$10,227	$13,121	$13,535	$0	$618	$0	$0	$0	$0	$0	$0	$416,280
	b. Clearings to Plant		5,180	10,167	11,146	1,682	2,031,705	618	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	$313,275	318,455	328,622	339,768	341,450	2,373,155	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	
3	Less: Accumulated Depreciation	(304)	(922)	(1,560)	(2,220)	(2,883)	(5,519)	(10,128)	(14,737)	(19,346)	(23,955)	(28,564)	(33,173)	(37,782)	
4	CWIP - Non-Interest Bearing	1,644,217	2,017,817	2,017,877	2,019,852	2,031,705	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$1,957,188	2,335,350	2,344,939	2,357,400	2,370,272	2,367,636	2,363,645	2,359,036	2,354,427	2,349,818	2,345,209	2,340,600	2,335,991	
6	Average Net Investment		2,146,269	2,340,145	2,351,169	2,363,836	2,368,954	2,365,641	2,361,341	2,356,732	2,352,123	2,347,514	2,342,905	2,338,296	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		19,960	21,763	21,866	21,984	22,031	22,000	21,960	21,918	21,875	21,832	21,789	21,746	$260,724
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		3,649	3,978	3,997	4,019	4,027	4,022	4,014	4,006	3,999	3,991	3,983	3,975	47,660
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.33%		618	638	660	663	2,636	4,609	4,609	4,609	4,609	4,609	4,609	4,609	37,478
	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 0.009270		246	254	262	264	1,833	1,834	1,834	1,834	1,834	1,834	1,834	1,834	15,697
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		24,473	26,633	26,785	26,930	30,527	32,465	32,417	32,367	32,317	32,266	32,215	32,164	361,559
	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		24,473	26,633	26,785	26,930	30,527	32,465	32,417	32,367	32,317	32,266	32,215	32,164	361,559

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															$0
	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. 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		(27,798)	(28,592)	(29,386)	(30,180)	(30,974)	(31,768)	(32,562)	(33,356)	(34,150)	(34,944)	(35,738)	(36,532)	(37,326)	
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)		$113,636	112,842	112,048	111,254	110,460	109,666	108,872	108,078	107,284	106,490	105,696	104,902	104,108	
6	Average Net Investment			113,239	112,445	111,651	110,857	110,063	109,269	108,475	107,681	106,887	106,093	105,299	104,505	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,053	1,046	1,038	1,031	1,024	1,016	1,009	1,001	994	987	979	972	$12,150
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		193	191	190	188	187	186	184	183	182	180	179	178	2,221
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.74%		794	794	794	794	794	794	794	794	794	794	794	794	9,528
	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	0.013790		163	163	163	163	163	163	163	163	163	163	163	163	1,956
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,203	2,194	2,185	2,176	2,168	2,159	2,150	2,141	2,133	2,124	2,115	2,107	25,855
	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			2,203	2,194	2,185	2,176	2,168	2,159	2,150	2,141	2,133	2,124	2,115	2,107	25,855

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															$0
	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. 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		($12,522)	(13,330)	(14,138)	(14,946)	(15,754)	(16,562)	(17,370)	(18,178)	(18,986)	(19,794)	(20,602)	(21,410)	(22,218)	
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)		$277,776	276,968	276,160	275,352	274,544	273,736	272,928	272,120	271,312	270,504	269,696	268,888	268,080	
6	Average Net Investment			277,372	276,564	275,756	274,948	274,140	273,332	272,524	271,716	270,908	270,100	269,292	268,484	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,580	2,572	2,565	2,557	2,550	2,542	2,534	2,527	2,519	2,512	2,504	2,497	$30,459
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		472	470	469	467	466	465	463	462	461	459	458	456	5,568
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.34%		808	808	808	808	808	808	808	808	808	808	808	808	9,696
	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	0.007100		172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787
	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			4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Deatil Support - January 2009 through December 2009
Pipline Intergrity Management (Project 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-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$166,822	$34	$0	$0	$0	$0	$0	$0	$0	$0	$0	$166,856
	b. Clearings to Plant		0	166,822	34	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	$1,868,841	1,868,841	2,035,664	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	
3	Less: Accumulated Depreciation	(2,204)	(6,611)	(11,412)	(16,213)	(21,014)	(25,815)	(30,616)	(35,417)	(40,218)	(45,019)	(49,820)	(54,621)	(59,422)	
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)	$1,866,638	1,862,231	2,024,252	2,019,485	2,014,684	2,009,883	2,005,082	2,000,281	1,995,480	1,990,679	1,985,878	1,981,077	1,976,276	
6	Average Net Investment		1,864,435	1,943,242	2,021,869	2,017,085	2,012,284	2,007,483	2,002,682	1,997,881	1,993,080	1,988,279	1,983,478	1,978,677	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	17,339	18,072	18,803	18,759	18,714	18,670	18,625	18,580	18,536	18,491	18,446	18,402	$221,437
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%	3,170	3,304	3,437	3,429	3,421	3,413	3,405	3,396	3,388	3,380	3,372	3,364	40,479
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	2.83%	4,407	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	57,218
	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	0.010450	1,632	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	21,190
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		26,548	27,955	28,819	28,767	28,714	28,662	28,609	28,555	28,503	28,450	28,397	28,345	340,324
	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		26,548	27,955	28,819	28,767	28,714	28,662	28,609	28,555	28,503	28,450	28,397	28,345	340,324

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$100,608	$2,351	$115,103	$40,105	$85,722	$5	$0	$0	$0	$0	$0	$343,894
	b. Clearings to Plant		0	0	0	0	0	343,888	5	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	343,888	343,893	343,893	343,893	343,893	343,893	343,893	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	(798)	(2,394)	(3,990)	(5,586)	(7,182)	(8,778)	(10,374)	
4	CWIP - Non-Interest Bearing	0	0	100,608	102,959	218,062	258,167	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	100,608	102,959	218,062	258,167	343,090	341,499	339,903	338,307	336,711	335,115	333,519	
6	Average Net Investment		0	50,304	101,783	160,510	238,114	300,628	342,294	340,701	339,105	337,509	335,913	334,317	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	0	468	947	1,493	2,214	2,796	3,183	3,169	3,154	3,139	3,124	3,109	$26,796
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%	0	86	173	273	405	511	582	579	576	574	571	568	4,898
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	5.57%	0	0	0	0	0	798	1,596	1,596	1,596	1,596	1,596	1,596	10,374
	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	0.009130	0	0	0	0	0	262	262	262	262	262	262	262	1,834
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	554	1,120	1,766	2,619	4,367	5,623	5,606	5,588	5,571	5,553	5,535	43,902
	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	554	1,120	1,766	2,619	4,367	5,623	5,606	5,588	5,571	5,553	5,535	43,902

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		(2,417)	(2,595)	(2,773)	(2,951)	(3,129)	(3,307)	(3,485)	(3,663)	(3,841)	(4,019)	(4,197)	(4,375)	(4,553)	
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)		$159,337	159,159	158,981	158,803	158,625	158,447	158,269	158,091	157,913	157,735	157,557	157,379	157,201	
6	Average Net Investment			159,248	159,070	158,892	158,714	158,536	158,358	158,180	158,002	157,824	157,646	157,468	157,290	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,481	1,479	1,478	1,476	1,474	1,473	1,471	1,469	1,468	1,466	1,464	1,463	$17,662
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		271	270	270	270	270	269	269	269	268	268	268	267	3,229
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.32%		178	178	178	178	178	178	178	178	178	178	178	178	2,136
	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	0.008760		118	118	118	118	118	118	118	118	118	118	118	118	1,416
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,048	2,045	2,044	2,042	2,040	2,038	2,036	2,034	2,032	2,030	2,028	2,026	24,443
	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			2,048	2,045	2,044	2,042	2,040	2,038	2,036	2,034	2,032	2,030	2,028	2,026	24,443

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		(10,165)	(10,924)	(11,683)	(12,442)	(13,201)	(13,960)	(14,719)	(15,478)	(16,237)	(16,996)	(17,755)	(18,514)	(19,273)	
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)		$265,182	264,423	263,664	262,905	262,146	261,387	260,628	259,869	259,110	258,351	257,592	256,833	256,074	
6	Average Net Investment			264,803	264,044	263,285	262,526	261,767	261,008	260,249	259,490	258,731	257,972	257,213	256,454	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,463	2,456	2,449	2,441	2,434	2,427	2,420	2,413	2,406	2,399	2,392	2,385	$29,085
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		450	449	448	446	445	444	442	441	440	439	437	436	5,317
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.31%		759	759	759	759	759	759	759	759	759	759	759	759	9,108
	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	0.009130		209	209	209	209	209	209	209	209	209	209	209	209	2,508
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,881	3,873	3,865	3,855	3,847	3,839	3,830	3,822	3,814	3,806	3,797	3,789	46,018
	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			3,881	3,873	3,865	3,855	3,847	3,839	3,830	3,822	3,814	3,806	3,797	3,789	46,018

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Dastill Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$196,986	196,988	196,988	196,988	196,988	196,988	196,988	196,988	196,988	196,988	196,988	196,988	196,988	
3	Less: Accumulated Depreciation		(5,847)	(6,283)	(6,719)	(7,155)	(7,591)	(8,027)	(8,463)	(8,899)	(9,335)	(9,771)	(10,207)	(10,643)	(11,079)	
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)		$193,141	192,705	192,269	191,833	191,397	190,961	190,525	190,089	189,653	189,217	188,781	188,345	187,909	
6	Average Net Investment			192,923	192,487	192,051	191,615	191,179	190,743	190,307	189,871	189,435	188,999	188,563	188,127	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,794	1,790	1,786	1,782	1,778	1,774	1,770	1,766	1,762	1,758	1,754	1,750	$21,264
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		328	327	326	326	325	324	324	323	322	321	321	320	3,887
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.63%		436	436	436	436	436	436	436	436	436	436	436	436	5,232
	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	0.009130		151	151	151	151	151	151	151	151	151	151	151	151	1,812
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,709	2,704	2,699	2,695	2,690	2,685	2,681	2,676	2,671	2,666	2,662	2,657	32,195
	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			2,709	2,704	2,699	2,695	2,690	2,685	2,681	2,676	2,671	2,666	2,662	2,657	32,195

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		(3,399)	(3,647)	(3,895)	(4,143)	(4,391)	(4,639)	(4,887)	(5,135)	(5,383)	(5,631)	(5,879)	(6,127)	(6,375)	
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)		$84,269	84,020	83,772	83,524	83,276	83,028	82,780	82,532	82,284	82,036	81,788	81,540	81,292	
6	Average Net Investment			84,144	83,896	83,648	83,400	83,152	82,904	82,656	82,408	82,160	81,912	81,664	81,416	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		783	780	778	776	773	771	769	766	764	762	759	757	$9,238
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		143	143	142	142	141	141	141	140	140	139	139	138	1,689
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.39%		248	248	248	248	248	248	248	248	248	248	248	248	2,976
	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	0.009270		68	68	68	68	68	68	68	68	68	68	68	68	816
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,242	1,239	1,236	1,234	1,230	1,228	1,226	1,222	1,220	1,217	1,214	1,211	14,719
	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			1,242	1,239	1,236	1,234	1,230	1,228	1,226	1,222	1,220	1,217	1,214	1,211	14,719

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Distri Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	
3	Less: Accumulated Depreciation		(3,241)	(3,529)	(3,817)	(4,105)	(4,393)	(4,681)	(4,969)	(5,257)	(5,545)	(5,833)	(6,121)	(6,409)	(6,697)	
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)		$342,249	341,961	341,673	341,385	341,097	340,809	340,521	340,233	339,945	339,657	339,369	339,081	338,793	
6	Average Net Investment			342,105	341,817	341,529	341,241	340,953	340,665	340,377	340,089	339,801	339,513	339,225	338,937	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,182	3,179	3,176	3,174	3,171	3,168	3,166	3,163	3,160	3,157	3,155	3,152	$38,003
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		582	581	581	580	580	579	579	578	578	577	577	576	6,948
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.00%		288	288	288	288	288	288	288	288	288	288	288	288	3,456
	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	0.009130		263	263	263	263	263	263	263	263	263	263	263	263	3,156
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,315	4,311	4,308	4,305	4,302	4,298	4,296	4,292	4,289	4,285	4,283	4,279	51,563
	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			4,315	4,311	4,308	4,305	4,302	4,298	4,296	4,292	4,289	4,285	4,283	4,279	51,563

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		(10,267)	(11,033)	(11,799)	(12,565)	(13,331)	(14,097)	(14,863)	(15,629)	(16,395)	(17,161)	(17,927)	(18,693)	(19,459)	
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)		$339,317	338,551	337,785	337,019	336,253	335,487	334,721	333,955	333,189	332,423	331,657	330,891	330,125	
6	Average Net Investment			338,934	338,168	337,402	336,636	335,870	335,104	334,338	333,572	332,806	332,040	331,274	330,508	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,152	3,145	3,138	3,131	3,124	3,116	3,109	3,102	3,095	3,088	3,081	3,074	$37,355
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		576	575	574	572	571	570	568	567	566	564	563	562	6,828
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.63%		766	766	766	766	766	766	766	766	766	766	766	766	9,192
	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	0.007740		225	225	225	225	225	225	225	225	225	225	225	225	2,700
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,719	4,711	4,703	4,694	4,686	4,677	4,668	4,660	4,652	4,643	4,635	4,627	56,075
	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			4,719	4,711	4,703	4,694	4,686	4,677	4,668	4,660	4,652	4,643	4,635	4,627	56,075

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Dept/ Support - January 2009 through December 2009
Pipline Integrity Management (Project 3 Recap)

For Project: CAIR CTs - TURNER (Project 7.2g)
(In Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(4,095)	(4,401)	(4,707)	(5,013)	(5,319)	(5,625)	(5,931)	(6,237)	(6,543)	(6,849)	(7,155)	(7,461)	(7,767)	
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)	$129,917	129,611	129,305	128,999	128,693	128,387	128,081	127,775	127,469	127,163	126,857	126,551	126,245	
6	Average Net Investment		129,764	129,458	129,152	128,846	128,540	128,234	127,928	127,622	127,316	127,010	126,704	126,398	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	1,207	1,204	1,201	1,198	1,195	1,193	1,190	1,187	1,184	1,181	1,178	1,176	$14,294
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%	221	220	220	219	219	218	217	217	216	216	215	215	2,613
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	2.74%	306	306	306	306	306	306	306	306	306	306	306	306	3,672
	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	0.009270	104	104	104	104	104	104	104	104	104	104	104	104	1,248
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,838	1,834	1,831	1,827	1,824	1,821	1,817	1,814	1,810	1,807	1,803	1,801	21,827
	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		1,838	1,834	1,831	1,827	1,824	1,821	1,817	1,814	1,810	1,807	1,803	1,801	21,827

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(In Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(7,734)	(8,408)	(9,082)	(9,756)	(10,430)	(11,104)	(11,778)	(12,452)	(13,126)	(13,800)	(14,474)	(15,148)	(15,822)	
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)	$373,826	373,152	372,478	371,804	371,130	370,456	369,782	369,108	368,434	367,760	367,086	366,412	365,738	
6	Average Net Investment		373,489	372,815	372,141	371,467	370,793	370,119	369,445	368,771	368,097	367,423	366,749	366,075	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	3,473	3,467	3,461	3,455	3,448	3,442	3,436	3,430	3,423	3,417	3,411	3,404	$41,267
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%	635	634	633	631	630	629	628	627	626	625	623	622	7,543
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	*Investment Expenses*														
	a. Depreciation	2.12%	674	674	674	674	674	674	674	674	674	674	674	674	8,088
	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	0.007850	250	250	250	250	250	250	250	250	250	250	250	250	3,000
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,032	5,025	5,018	5,010	5,002	4,995	4,988	4,981	4,973	4,966	4,958	4,950	59,898
	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		5,032	5,025	5,018	5,010	5,002	4,995	4,988	4,981	4,973	4,966	4,958	4,950	59,898

For Project: CAIR/CAMR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$77,700	($799,917)	$49,876	$48	$0	$0	$0	$0	$0	$0	$0	($672,293)
	b. Clearings to Plant			0	77,700	(799,917)	49,876	48	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		$16,162,675	16,162,675	16,240,375	15,440,458	15,490,334	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	
3	Less: Accumulated Depreciation		(334,407)	(380,067)	(425,946)	(469,565)	(513,325)	(557,085)	(600,845)	(644,605)	(688,365)	(732,125)	(775,885)	(819,645)	(863,405)	
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)		$15,828,268	15,782,608	15,814,429	14,970,894	14,977,009	14,933,297	14,889,537	14,845,777	14,802,017	14,758,257	14,714,497	14,670,737	14,626,977	
6	Average Net Investment			15,805,438	15,798,519	15,392,662	14,973,952	14,955,153	14,911,417	14,867,657	14,823,897	14,780,137	14,736,377	14,692,617	14,648,857	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		146,991	146,926	143,152	139,258	139,083	138,676	138,269	137,862	137,455	137,048	136,641	136,234	$1,677,595
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		26,869	26,857	26,168	25,456	25,424	25,349	25,275	25,201	25,126	25,052	24,977	24,903	306,657
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.39%		45,660	45,879	43,619	43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	528,998
	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	0.010480		14,115	14,183	13,485	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	163,535
	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)			233,635	233,845	226,424	222,002	221,795	221,313	220,832	220,351	219,869	219,388	218,906	218,425	2,676,785
	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			233,635	233,845	226,424	222,002	221,795	221,313	220,832	220,351	219,869	219,388	218,906	218,425	2,676,785

For Project: CAIR/CAMR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$1,596,194	$4,331	$127,144	$14,146	$3,030,352	$50,405	$0	$0	$0	$0	$0	$0	$4,822,572
	b. Clearings to Plant			1,596,194	4,331	127,144	14,146	3,030,352	50,405	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		$5,599,409	7,195,602	7,199,934	7,327,077	7,341,223	10,371,575	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	
3	Less: Accumulated Depreciation		(6,603)	(23,573)	(40,553)	(57,833)	(75,146)	(99,606)	(124,185)	(148,764)	(173,343)	(197,922)	(222,501)	(247,080)	(271,659)	
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)		$5,592,806	7,172,030	7,159,381	7,269,245	7,266,078	10,271,970	10,297,796	10,273,217	10,248,638	10,224,059	10,199,480	10,174,901	10,150,322	
6	Average Net Investment			6,382,418	7,165,706	7,214,313	7,267,661	8,769,024	10,284,883	10,285,506	10,260,927	10,236,348	10,211,769	10,187,190	10,162,611	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		59,356	66,641	67,093	67,589	81,552	95,649	95,655	95,427	95,198	94,969	94,741	94,512	$1,008,382
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		10,850	12,182	12,264	12,355	14,907	17,484	17,485	17,444	17,402	17,360	17,318	17,276	184,327
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		16,970	16,980	17,280	17,313	24,460	24,579	24,579	24,579	24,579	24,579	24,579	24,579	265,056
	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	0.010480		6,284	6,288	6,399	6,411	9,058	9,102	9,102	9,102	9,102	9,102	9,102	9,102	98,154
	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)			93,460	102,091	103,036	103,668	129,977	146,814	146,821	146,552	146,281	146,010	145,740	145,469	1,555,919
	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			93,460	102,091	103,036	103,668	129,977	146,814	146,821	146,552	146,281	146,010	145,740	145,469	1,555,919

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2009 through December 2009
Pipline Integrity Management (Project 3 Recap)

For Project: CAIR/CAMR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$91,273,742	648,614	465,714	44,167	20,833	20,833	20,833	$92,494,737
	b. Clearings to Plant			0	0	0	0	0	91,273,742	648,614	465,714	44,167	20,833	20,833	20,833	
	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	91,273,742	91,922,356	92,388,070	92,432,237	92,453,070	92,473,903	92,494,737	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	(107,627)	(324,411)	(542,293)	(760,279)	(978,314)	(1,196,398)	(1,414,531)	
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	91,166,115	91,597,945	91,845,777	91,671,958	91,474,756	91,277,505	91,080,206	
6	Average Net Investment			0	0	0	0	0	45,583,058	91,382,030	91,721,861	91,758,867	91,573,357	91,376,131	91,178,856	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	0	423,922	849,853	853,013	853,357	851,632	849,798	847,963	$5,529,538
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	77,491	155,349	155,927	155,990	155,675	155,339	155,004	1,010,775
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		0	0	0	0	0	107,627	216,784	217,882	217,986	218,035	218,084	218,133	1,414,531
	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	0.010480		0	0	0	0	0	79,712	80,279	80,686	80,724	80,742	80,761	80,779	563,683
	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	688,752	1,302,265	1,307,508	1,308,057	1,306,084	1,303,982	1,301,879	8,518,527
	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	688,752	1,302,265	1,307,508	1,308,057	1,306,084	1,303,982	1,301,879	8,518,527

For Project: CAIR/CAMR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$634,421,721	$634,421,721
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	634,421,721	
	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	634,421,721	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(748,089)	
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)		$0	0	0	0	0	0	0	0	0	0	0	0	633,673,632	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	316,836,816	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	0	0	0	0	0	0	0	2,946,582	$2,946,582
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	0	538,623	538,623
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		0	0	0	0	0	0	0	0	0	0	0	748,089	748,089
	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	0.010480		0	0	0	0	0	0	0	0	0	0	0	554,062	554,062
	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	4,787,356	4,787,356
	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	4,787,356	4,787,356

For Project: CAIR/CAMR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	69,831,473	$0	$0	$0	$0	$0	$69,831,473
	b. Clearings to Plant		0	0	0	0	0	0	69,831,473	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	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(82,343)	(247,029)	(411,715)	(576,401)	(741,087)	(905,773)	
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)	$0	0	0	0	0	0	0	69,749,130	69,584,444	69,419,758	69,255,072	69,090,386	68,925,700	
6	Average Net Investment		0	0	0	0	0	0	34,874,565	69,666,787	69,502,101	69,337,415	69,172,729	69,008,043	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	324,333	647,901	646,370	644,838	643,306	641,775	$3,548,523
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	59,287	118,434	118,154	117,874	117,594	117,314	648,657
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.83%		0	0	0	0	0	0	82,343	164,686	164,686	164,686	164,686	164,686	905,773
	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 0.010480		0	0	0	0	0	0	60,986	60,986	60,986	60,986	60,986	60,986	365,916
	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	526,949	992,007	990,196	988,384	986,572	984,761	5,468,869
	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	526,949	992,007	990,196	988,384	986,572	984,761	5,468,869

For Project: CAIR/CAMR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	135,013,655	$135,013,655
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	135,013,655	
	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	135,013,655	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(159,204)	
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	134,854,452	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	67,427,226	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	0	0	0	0	0	627,073	$627,073
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	0	0	114,626	114,626
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.83%		0	0	0	0	0	0	0	0	0	0	0	159,204	159,204
	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 0.010480		0	0	0	0	0	0	0	0	0	0	0	117,912	117,912
	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	1,018,815	1,018,815
	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	1,018,815	1,018,815

For Project: CAIR/CAMR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing Controls(Project 7.4g)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$ 929,220	$929,220
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	929,220	
	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	929,220	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(1,096)	
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	928,125	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	464,062	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	0	0	0	0	0	4,316	$4,316
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	0	0	789	789
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.83%		0	0	0	0	0	0	0	0	0	0	0	1,096	1,096
	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 0.010480		0	0	0	0	0	0	0	0	0	0	0	812	812
	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	7,013	7,013
	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	7,013	7,013

Witness: T.G. Foster
Exhibit__(TGF -3)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1P THROUGH 42-7P

JANUARY 2010 - DECEMBER 2010
Calculation of the Projected Period Amount
January through December 2010
DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 26
COMPANY Progress Energy Florida, Inc.
WITNESS Thomas G. Foster (TGF-3)
DATE 11/02/09

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.__(TGF-3)
Page 1 of 39

PROGRESS ENERGY FLORIDA

Form 42-1P

Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered
For the Projected Period
JANUARY 2010 - DECEMBER 2010
(in Dollars)

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)	$31,802,843	$725,904	$9,858,302	$4,532,180	$46,919,229
	b Projected Capital Projects (Form 42-3P, Lines 7 through 9)	204,080,320	0	7,083	2,582,417	206,669,820
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	$235,883,163	$725,904	$9,865,385	$7,114,597	$253,589,049
2	True-up for Estimated Over/(Under) Recovery for the current period January 2009 - December 2009 (Form 42-2E, Line 5 + 6 + 10)	18,198,931	579,224	3,425,915	1,871,512	$24,075,581
3	Final True-up for the period January 2008 - December 2008 (Form 42-1A, Line 3)	(1,372,802)	(187,999)	(2,347,539)	(412,265)	($4,320,606)
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2009 - December 2009 (Line 1 - Line 2 - Line 3)	$219,057,035	$334,679	$8,787,009	$5,655,350	$233,834,074
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$219,214,756	$334,920	$8,793,336	$5,659,422	$234,002,435

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010

Form 42-2P

O&M Activities
(in Dollars)

Line	Description	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$1,063,496
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	84,326	84,326	84,326	84,326	84,326	84,326	84,326	84,326	84,326	84,326	84,326	84,326	1,011,915
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	1,282,200	1,372,000	1,214,200	1,092,800	1,039,600	831,800	756,800	555,000	313,200	313,200	108,000	-	8,880,800
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	145,429	120,429	120,429	120,429	120,429	120,429	120,429	64,000	64,000	74,000	74,000	74,000	1,218,000
	4 Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO2 and NOX Emissions Allowances - Energy	997,263	670,619	599,866	615,537	1,264,469	1,160,949	1,063,837	1,138,392	1,002,939	664,810	504,739	524,189	10,207,630
	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 - Peaking	0	0	16,825	0	0	16,825	0	0	16,825	0	0	16,625	67,300
	7.4 CAIR Crystal River AFUDC - Base	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	6,744,196
	7.4 CAIR Crystal River AFUDC - Energy	896,037	632,327	955,526	894,414	706,438	1,502,514	1,465,862	1,986,179	1,923,610	1,919,454	1,571,213	2,041,688	16,295,261
	7.4 CAIR Crystal River - A&G	1,298	1,298	1,298	1,947	1,298	1,298	1,298	1,298	1,298	1,947	1,298	1,298	16,871
	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	150	150	150	150	150	150	150	150	150	150	150	150	1,800
	11 Modular Cooling Towers - Base	0	0	0	0	0	834,188	834,188	834,188	1,038,867	204,679	204,679	204,679	4,155,466
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	3,750	3,750	3,750	3,750	3,750	3,750	22,500
	13 Mercury Total Maximum Daily Loads Monitoring - Energy	0	0	9,019	0	0	9,019	0	0	9,019	0	0	9,020	36,077
2	Total of O&M Activities	3,857,343	3,531,790	3,652,279	3,460,244	3,867,350	5,212,138	4,983,281	5,317,924	5,108,625	3,916,957	3,202,816	3,610,566	49,721,312
3	Recoverable Costs Allocated to Energy	1,693,300	1,302,946	1,564,411	1,509,951	1,970,906	2,672,462	2,553,449	3,128,321	2,939,316	2,588,014	2,079,722	2,578,647	26,561,466
4	Recoverable Costs Allocated to Demand - Transm	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	1,063,496
	Recoverable Costs Allocated to Demand - Distrib	1,366,676	1,456,476	1,298,676	1,177,276	1,124,076	916,276	843,276	639,476	397,676	397,676	192,476	84,476	9,894,515
	Recoverable Costs Allocated to Demand - Prod-Base	562,016	562,016	562,016	562,016	562,016	1,398,204	1,398,204	1,398,204	1,660,883	766,695	766,695	766,695	10,899,662
	Recoverable Costs Allocated to Demand - Prod-Intm	145,429	120,429	120,429	120,429	120,429	120,429	120,429	64,000	64,000	74,000	74,000	74,000	1,218,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	16,825	0	0	16,825	0	0	16,825	0	0	16,825	67,300
	Recoverable Costs Allocated to Demand - A&G	1,298	1,298	1,298	1,947	1,298	1,298	1,298	1,298	1,298	1,947	1,298	1,298	16,871
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
6	Retail Transmission Demand Jurisdictional Factor	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	
	Retail Distribution Demand Jurisdictional Factor	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	
	Retail Production Demand Jurisdictional Factor - Base	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
	Retail Production Demand Jurisdictional Factor - Intm	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
	Retail Production Demand Jurisdictional Factor - Peaking	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
	Retail Production Demand Jurisdictional Factor - A&G	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	
7	Jurisdictional Energy Recoverable Costs (A)	1,638,775	1,253,695	1,511,690	1,459,368	1,907,443	2,591,238	2,432,871	2,996,619	2,814,397	2,474,659	1,988,006	2,475,243	25,544,064
8	Jurisdictional Demand Recoverable Costs - Transm (B)	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	725,904
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,361,674	1,451,146	1,293,923	1,172,967	1,119,962	912,923	840,180	637,136	396,221	396,221	191,772	84,167	9,858,302
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	515,195	515,195	515,195	515,195	515,195	1,279,887	1,279,887	1,279,887	1,467,513	702,821	702,821	702,821	9,991,612
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	86,315	71,477	71,477	71,477	71,477	71,477	71,477	37,985	37,985	43,920	43,920	43,920	722,907
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	15,431	0	0	15,431	0	0	15,431	0	0	15,431	61,724
	Jurisdictional Demand Recoverable Costs - A&G (B)	1,137	1,137	1,137	1,705	1,137	1,137	1,137	1,137	1,137	1,705	1,137	1,137	14,776
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$3,663,588	$3,353,142	$3,469,345	$3,281,204	$3,675,706	$4,932,585	$4,686,054	$5,013,256	$4,793,178	$3,679,818	$2,988,148	$3,383,211	$48,919,229

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

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Progress Energy Florida
Witness: T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Capital Investment Projects-Recoverable Costs
(in Dollars)

Form 42-3P

Line	Description	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$51,083	$50,894	$50,725	$50,556	$50,388	$50,220	$50,051	$49,884	$49,714	$49,545	$49,376	$49,206	$601,626
4.1	Above Ground Tank Secondary Containment - Peaking	148,001	148,816	156,400	158,883	158,360	157,317	156,796	156,272	155,750	155,229	154,709	154,709	1,864,373
4.2	Above Ground Tank Secondary Containment - Base	28,359	28,310	28,259	28,209	28,158	28,108	28,058	28,008	27,957	27,906	27,855	27,806	336,994
4.3	Above Ground Tank Secondary Containment - Intermediate	4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,046	4,037	4,025	49,048
5	SO2/NOX Emissions Allowances - Energy	381,809	352,636	345,850	338,965	328,628	315,287	303,053	290,941	279,164	269,993	263,560	257,901	3,707,585
7.1	CAIR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR CT's - Peaking	27,209	27,148	27,085	27,023	26,960	26,902	26,842	26,778	26,718	26,656	26,594	26,534	322,447
7.3	CAIR Crystal River - Base	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
7.4	CAIR Crystal River AFUDC - Base	15,994,688	15,754,492	15,754,154	15,734,060	17,818,501	19,703,143	19,705,543	19,675,942	19,625,489	19,573,209	19,520,821	19,468,409	218,268,451
7.4	CAIR Crystal River AFUDC - Energy	8,150	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	99,341
9	Sea Turtle - Coastal Street Lighting -Distribution	462	480	510	536	553	583	609	625	654	678	695	724	7,109
10.1	Underground Storage Tanks-Base	2,281	2,276	2,271	2,267	2,262	2,257	2,252	2,248	2,243	2,238	2,234	2,229	27,058
10.2	Underground Storage Tanks-Intermediate	1,012	1,010	1,007	1,006	1,004	1,001	999	997	995	992	991	988	12,002
11	Modular Cooling Towers - Base	13,893	13,772	13,650	13,527	13,408	13,283	13,162	13,040	12,918	12,796	12,674	12,552	156,673
11.1	Crystal River Thermal Discharge Compliance Project - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	16,584,257	16,396,441	16,394,307	16,370,640	18,443,792	20,314,187	20,303,437	20,260,799	20,197,632	20,135,283	20,075,538	20,018,555	225,492,867
3	Recoverable Costs Allocated to Energy	369,959	380,926	353,940	347,255	336,916	323,577	311,343	299,231	287,454	278,283	271,650	265,191	3,806,926
	Recoverable Costs Allocated to Demand - Distribution	462	480	510	536	553	583	609	625	654	678	695	724	7,109
4	Recoverable Costs Allocated to Demand - Production - Base	15,982,401	15,802,030	15,801,513	15,781,263	17,865,507	19,749,971	19,752,195	19,722,418	19,671,767	19,619,331	19,566,764	19,514,176	216,829,336
	Recoverable Costs Allocated to Demand - Production - Intermediate	56,225	56,043	55,859	55,660	55,496	55,314	55,131	54,951	54,767	54,585	54,404	54,221	662,676
	Recoverable Costs Allocated to Demand - Production - Peaking	175,210	176,962	182,485	185,906	185,320	184,742	184,159	183,574	182,990	182,406	181,823	181,243	2,186,820
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.98030	0.95790	0.95750	0.96620	0.95590	0.95890	
	Retail Distribution Demand Jurisdictional Factor	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	
6	Retail Demand Jurisdictional Factor - Production - Base	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
7	Jurisdictional Energy Recoverable Costs (B)	358,048	347,283	342,012	335,622	326,067	313,740	298,983	286,633	275,237	266,094	259,662	255,517	3,665,098
	Jurisdictional Demand Recoverable Costs - Distribution (B)	460	478	508	534	551	581	607	623	652	676	692	721	7,083
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	14,650,907	14,485,563	14,485,089	14,466,526	16,377,132	18,104,601	18,106,640	18,079,343	18,032,912	17,984,845	17,936,657	17,888,450	200,598,664
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	33,371	33,263	33,153	33,047	32,938	32,830	32,721	32,615	32,505	32,397	32,290	32,181	393,311
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	160,696	162,302	167,368	170,506	169,966	169,438	168,903	168,367	167,831	167,295	166,761	166,229	2,005,664
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$15,203,480	$15,028,889	$15,028,131	$15,006,235	$16,906,656	$18,621,190	$18,607,854	$18,567,581	$18,509,137	$18,451,307	$18,396,282	$18,343,098	$206,669,820

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	
3	Less: Accumulated Depreciation		(565,408)	(580,744)	(596,080)	(611,416)	(626,752)	(642,088)	(657,424)	(672,760)	(688,096)	(703,432)	(718,768)	(734,104)	(749,440)	
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)		$3,014,328	2,998,992	2,983,656	2,968,320	2,952,984	2,937,648	2,922,312	2,906,976	2,891,640	2,876,304	2,860,968	2,845,632	2,830,296	
6	Average Net Investment			3,006,660	2,991,324	2,975,988	2,960,652	2,945,316	2,929,980	2,914,644	2,899,308	2,883,972	2,868,636	2,853,300	2,837,964	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		25,922	25,790	25,657	25,526	25,393	25,262	25,129	24,996	24,865	24,732	24,600	24,468	302,342
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.65%		7,148	7,111	7,075	7,039	7,002	6,966	6,929	6,893	6,856	6,820	6,783	6,747	83,368
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	184,032
	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)			2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	31,884
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			51,063	50,894	50,725	50,556	50,388	50,220	50,051	49,884	49,714	49,545	49,376	49,206	601,626
	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			51,063	50,894	50,725	50,556	50,388	50,220	50,051	49,884	49,714	49,545	49,376	49,206	601,626
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	N/A
11	Demand Jurisdictional Factor - Production (Intermediate)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352
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)			30,307	30,207	30,106	30,007	29,906	29,807	29,706	29,607	29,506	29,406	29,306	29,206	357,077
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$30,307	$30,207	$30,106	$30,007	$29,906	$29,807	$29,706	$29,607	$29,506	$29,406	$29,306	$29,206	$357,077

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.35%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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. Based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Lines 2 x 89% @ .009130 x 1/12 + 11%@ .007100 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2008 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 2010 - DECEMBER 2010
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	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$156,000	$260,000	$223,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$639,000
	b. Clearings to Plant			0	0	1,513,040	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		$8,575,395	$8,575,395	$8,575,395	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	
3	Less: Accumulated Depreciation		(484,182)	(526,619)	(569,056)	(613,747)	(661,202)	(708,657)	(756,112)	(803,567)	(851,022)	(898,477)	(945,932)	(993,387)	(1,040,842)	
4	CWIP - Non-Interest Bearing		575,039	1,030,040	1,290,040	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$8,666,252	$9,078,816	$9,296,379	$9,474,688	$9,427,233	$9,379,778	$9,332,323	$9,284,868	$9,237,413	$9,189,958	$9,142,503	$9,095,048	$9,047,593	
6	Average Net Investment			$9,022,534	$9,187,597	$9,385,533	$9,450,960	$9,403,505	$9,356,050	$9,308,595	$9,261,140	$9,213,685	$9,166,230	$9,118,775	$9,071,320	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		77,789	79,211	80,919	81,484	81,074	80,666	80,255	79,847	79,437	79,028	78,619	78,211	956,540
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		21,451	21,844	22,315	22,469	22,356	22,244	22,132	22,019	21,905	21,792	21,680	21,568	263,775
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			42,437	42,437	44,691	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	566,660
	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	N/A
	d. Property Taxes (D)			6,324	6,324	7,475	7,475	7,475	7,475	7,475	7,475	7,475	7,475	7,475	7,475	87,393
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			148,001	149,816	155,400	158,883	158,360	157,840	157,317	156,796	156,272	155,750	155,229	154,709	1,864,373
	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			148,001	149,816	155,400	158,883	158,360	157,840	157,317	156,796	156,272	155,750	155,229	154,709	1,864,373
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)			0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
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)			135,741	137,406	142,527	145,721	145,241	144,765	144,285	143,807	143,326	142,848	142,370	141,893	1,709,928
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$135,741	$137,406	$142,527	$145,721	$145,241	$144,765	$144,285	$143,807	$143,326	$142,848	$142,370	$141,893	$1,709,928

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 8.38%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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 proposal in PEF's rate case Dkt. 090079-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 2008 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 2010 - DECEMBER 2010
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	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	
3	Less: Accumulated Depreciation		(67,969)	(72,539)	(77,109)	(81,679)	(86,249)	(90,819)	(95,389)	(99,959)	(104,529)	(109,099)	(113,669)	(118,239)	(122,809)	
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)		2,000,821	1,996,251	1,991,681	1,987,111	1,982,541	1,977,971	1,973,401	1,968,831	1,964,261	1,959,691	1,955,121	1,950,551	1,945,981	
6	Average Net Investment			$1,998,536	$1,993,966	$1,989,396	$1,984,826	$1,980,256	$1,975,686	$1,971,116	$1,966,546	$1,961,976	$1,957,406	$1,952,836	$1,948,266	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		$17,231	$17,192	$17,152	$17,113	$17,073	$17,034	$16,995	$16,955	$16,916	$16,877	$16,838	$16,797	$204,171
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		$4,751	$4,741	$4,729	$4,719	$4,708	$4,697	$4,686	$4,676	$4,664	$4,654	$4,642	$4,632	$56,299
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$54,840
	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)			1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	21,684
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			28,359	28,310	28,258	28,209	28,158	28,108	28,058	28,008	27,957	27,908	27,855	27,806	336,994
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			28,359	28,310	28,258	28,209	28,158	28,108	28,058	28,008	27,957	27,908	27,855	27,806	336,994
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			25,996	25,951	25,904	25,859	25,812	25,766	25,720	25,675	25,628	25,583	25,534	25,489	308,919
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$25,996	$25,951	$25,904	$25,859	$25,812	$25,766	$25,720	$25,675	$25,628	$25,583	$25,534	$25,489	$308,919

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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 proposal in PEF's rate case Dkt. 090079-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 2008 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 2010 - DECEMBER 2010
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	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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*		(22,218)	(23,253)	(24,288)	(25,323)	(26,358)	(27,393)	(28,428)	(29,463)	(30,498)	(31,533)	(32,568)	(33,603)	(34,638)	
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)		$268,080	267,045	266,010	264,975	263,940	262,905	261,870	260,835	259,800	258,765	257,730	256,695	255,660	
6	Average Net Investment			267,562	266,527	265,492	264,457	263,422	262,387	261,352	260,317	259,282	258,247	257,212	256,177	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		2,307	2,298	2,289	2,280	2,271	2,262	2,253	2,244	2,235	2,227	2,218	2,209	27,093
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.65%		636	634	631	629	626	624	621	619	616	614	612	609	7,471
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	12,420
	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)*			172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,048	4,037	4,025	49,048
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,048	4,037	4,025	49,048
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)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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)			2,463	2,457	2,449	2,443	2,436	2,429	2,422	2,416	2,409	2,403	2,396	2,389	29,111
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,463	$2,457	$2,449	$2,443	$2,436	$2,429	$2,422	$2,416	$2,409	$2,403	$2,396	$2,389	$29,111

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.64%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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 proposal in PEF's rate case Dkt. 090079-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 2008 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 2010 - DECEMBER 2010
Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 8)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	Period Total
1	Working Capital Dr (Cr)															
	a. 1561001 SO_2 Emission Allowance Inventory		$6,962,143	$6,745,933	$6,636,274	$6,533,561	$6,426,298	$6,218,410	$6,078,016	$5,936,225	$5,770,051	$5,616,163	$5,504,402	$5,418,997	$5,333,889	$5,333,889
	b. 25401FL Auctioned SO_2 Allowance		(1,821,713)	(1,909,321)	(1,896,928)	(1,884,535)	(1,872,142)	(1,832,869)	(1,819,124)	(1,797,359)	(1,779,594)	(1,761,829)	(1,744,064)	(1,726,299)	(1,708,534)	(1,708,534)
	c. 1561002 NOX Emission Allowance Inventory		29,412,466	27,559,022	26,985,869	26,478,134	25,955,456	24,859,622	23,821,302	22,661,491	21,891,508	21,022,672	20,453,877	20,015,758	19,569,912	19,569,912
2	Total Working Capital		$33,392,897	32,395,634	31,725,215	31,125,149	30,509,612	29,245,143	28,084,194	27,020,358	25,881,966	24,879,026	24,214,216	23,708,457	23,195,267	23,195,267
3	Average Net Investment			32,894,266	32,060,325	31,425,082	30,817,381	29,877,378	28,884,669	27,552,276	26,451,162	25,380,496	24,546,621	23,961,836	23,447,362	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	10.35%		283,603	276,413	270,997	265,697	257,593	247,137	237,547	228,083	218,822	211,633	206,591	202,155	$2,906,181
	b. Debt Component (Line 3 x 2.84% x 1/12)	2.85%		78,206	76,223	74,713	73,266	71,093	66,150	65,506	62,859	60,342	58,360	56,969	55,746	801,404
5	Total Return Component (B)			361,809	352,636	345,650	338,965	328,626	313,287	303,053	290,941	279,164	269,993	263,560	257,901	3,707,585
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			$158,210	$109,858	$102,724	$107,252	$207,889	$140,394	$141,791	$166,174	$161,869	$113,780	$84,405	$86,108	1,588,253
	b. 4074004 Amortization Expense			(12,393)	(12,393)	(12,393)	(12,393)	(38,254)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	($213,180)
	c. 5090003 Nox allowance expense			853,446	573,354	509,525	920,673	1,095,834	1,038,320	938,911	988,983	868,836	568,795	438,119	455,848	$8,852,556
7	Net Expense (C)			997,263	670,819	599,856	815,537	1,264,469	1,160,949	1,063,537	1,138,392	1,002,939	664,810	504,759	524,189	10,227,630
8	Total System Recoverable Expenses (Lines 5 + 7)			1,359,072	1,023,255	945,516	954,502	1,593,095	1,474,236	1,366,590	1,429,333	1,282,103	934,803	768,319	782,090	13,935,215
	a. Recoverable costs allocated to Energy			1,359,072	1,023,255	945,516	954,502	1,593,095	1,474,236	1,366,590	1,429,333	1,282,103	934,803	768,319	782,090	13,935,215
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96780	0.96220	0.96830	0.96550	0.96780	0.96960	0.96830	0.95790	0.95750	0.95620	0.95590	0.95960	
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)			1,315,310	984,576	913,652	922,526	1,541,797	1,431,358	1,312,624	1,369,158	1,227,614	893,659	734,436	750,729	13,397,640
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)			$ 1,315,310	$ 984,576	$ 913,652	$ 922,526	$ 1,541,797	$ 1,431,358	$ 1,312,624	$ 1,369,158	$ 1,227,614	$ 893,659	$ 734,436	$ 750,729	$ 13,397,640

Notes:
(A) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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 Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Intermediate (Project 7.1 - Anclote Low Nox Burners and SOFA)
(In Dollars)

Line	Description	Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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														
	a. Equity Component Grossed Up For Taxes (B)	10.35%	0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.65%	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)		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
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)		0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 5.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 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 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	
3	Less: Accumulated Depreciation		(91,024)	(96,599)	(102,174)	(107,749)	(113,324)	(118,899)	(124,474)	(130,049)	(135,624)	(141,199)	(146,774)	(152,349)	(157,924)	
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)		$1,843,377	1,837,802	1,832,227	1,826,652	1,821,077	1,815,502	1,809,927	1,804,352	1,798,777	1,793,202	1,787,627	1,782,052	1,776,477	
6	Average Net Investment			1,840,590	1,835,015	1,829,440	1,823,865	1,818,290	1,812,715	1,807,140	1,801,565	1,795,990	1,790,415	1,784,840	1,779,265	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		15,870	15,820	15,772	15,724	15,676	15,628	15,581	15,533	15,485	15,436	15,388	15,341	187,254
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		4,376	4,363	4,350	4,336	4,321	4,311	4,298	4,282	4,270	4,257	4,243	4,230	51,837
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	66,900
	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)			1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	16,658
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			27,209	27,146	27,085	27,023	26,960	26,902	26,842	26,778	26,718	26,656	26,594	26,534	322,447
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			27,209	27,146	27,085	27,023	26,960	26,902	26,842	26,778	26,718	26,656	26,594	26,534	322,447
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)			0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
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)			24,955	24,897	24,841	24,784	24,727	24,673	24,618	24,560	24,505	24,448	24,391	24,336	295,735
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$24,955	$24,897	$24,841	$24,784	$24,727	$24,673	$24,618	$24,560	$24,505	$24,448	$24,391	$24,336	$295,735

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.35%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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 proposal in PEF's rate case Dkt. 090079-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 2008 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 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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	
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															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	$29,916
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		687	687	687	687	687	687	687	687	687	687	687	687	8,244
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	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
9	Total System Recoverable Expenses (Lines 7 + 8)			3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
	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			3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	34,981
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$34,981

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 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 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Base - AFUDC (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			11,791,501	13,154,705	11,180,371	5,202,135	3,175,787	$3,433,939	$3,931,322	$889,781	$406,743	$387,177	$386,781	$386,885	$58,126,906
	b. Clearings to Plant			1,560,000	3,286,200	2,909,985	1,120,000	249,120,680	3,433,939	3,931,322	889,781	406,743	387,177	386,781	386,885	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)	7.667%		1,517,093	1,552,104	1,514,428	1,703,016	883,364	0	0	0	0	0	0	0	7,280,005
2	Plant-In-Service/Depreciation Base		$979,476,187	981,035,187	984,324,387	986,934,372	988,054,372	1,237,175,052	1,240,608,991	1,244,540,313	1,245,230,094	1,245,636,836	1,246,024,013	1,246,410,794	1,246,797,459	
3	Less: Accumulated Depreciation		($4,406,719)	(6,598,430)	(12,802,308)	(17,017,431)	(21,237,360)	(25,997,348)	(31,305,386)	(36,630,362)	(41,958,309)	(47,289,006)	(52,619,376)	(57,952,409)	(63,287,109)	
4	CWIP - AFUDC-Interest Bearing		201,914,362	213,862,956	225,081,585	235,266,379	245,051,530	0	0	0	0	0	0	0	0	65,406,911
5	Net Investment (Lines 2 + 3 + 4)		$1,176,981,830	1,186,100,712	1,196,603,644	1,205,183,319	1,211,868,521	1,211,177,704	1,209,303,605	1,207,909,951	1,203,271,785	1,198,348,829	1,193,404,636	1,188,458,386	1,183,510,350	
6	Average Net Investment			1,181,541,271	1,191,352,178	1,200,893,481	1,208,525,920	1,211,523,113	1,210,240,655	1,208,606,778	1,205,590,868	1,200,810,307	1,195,876,734	1,190,931,512	1,185,984,368	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		8,395,370	8,390,065	8,366,221	8,348,836	8,366,973	10,434,292	10,420,205	10,394,203	10,352,998	10,310,460	10,267,618	10,225,162	115,287,704
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		2,315,007	2,310,882	2,307,557	2,302,292	2,589,092	2,877,347	2,873,463	2,866,291	2,854,927	2,843,197	2,831,439	2,819,677	31,791,591
	c. Other (C)			114,545	0	0	0	0	0	0	0	0	0	0	0	114,545
8	Investment Expenses															
	a. Depreciation (D)			4,199,711	4,203,878	4,215,123	4,219,949	4,759,998	5,308,038	5,324,976	5,327,947	5,329,699	5,331,367	5,333,034	5,334,700	58,878,390
	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 (E)			856,772	859,644	861,923	862,901	1,060,467	1,063,466	1,066,899	1,067,501	1,067,857	1,068,195	1,068,532	1,068,870	12,133,027
	e. Other (F)			83,193	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			15,934,688	15,764,492	15,754,154	15,734,080	17,818,501	19,703,143	19,705,643	19,675,942	19,625,489	19,573,209	19,520,821	19,468,409	218,288,451
	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			15,934,688	15,764,492	15,754,154	15,734,080	17,818,501	19,703,143	19,705,643	19,675,942	19,625,489	19,573,209	19,520,821	19,468,409	218,288,451
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
12	Retail Energy-Related Recoverable Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs			14,607,159	14,441,985	14,441,675	14,423,274	16,334,042	18,061,674	18,063,874	18,036,739	17,990,471	17,942,565	17,894,541	17,846,496	200,084,506
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$14,607,159	$14,441,985	$14,441,675	$14,423,274	$16,334,042	$18,061,674	$18,063,874	$18,036,739	$17,990,471	$17,942,565	$17,894,541	$17,846,496	$200,084,506

Notes:
(A) AFUDC calculation based on proposal in PEF's rate case Dkt. 090079-EI.
(B) Return on equity and debt calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 6 x rate x 1/12. Rate based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) T/U amount for the equity and debt components of the average net investment that were inadvertently excluded in the 2009 Est/Actual filing.
(D) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on proposal in PEF's rate case Dkt. 090079-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(F) T/U amount for depreciation and property tax expenses that were inadvertently excluded in the 2009 Est/Actual filing.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
JANUARY 2010 - DECEMBER 2010

Schedule of Amortization and Return
For Project: CAIR - Energy - AFUDC (Project 7.4 - Reagents and By-products)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan - 10	Actual Feb - 10	Actual Mar - 10	Actual Apr - 10	Actual May - 10	Actual Jun - 10	Estimated Jul - 10	Estimated Aug - 10	Estimated Sep - 10	Estimated Oct - 10	Estimated Nov - 10	Estimated Dec - 10	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1544001 Ammonia Inventory		$158,148	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105
	b. 1544004 Limestone Inventory		$70,000	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600
2	Total Working Capital		$728,148	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705
3	Average Net Investment			740,926	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	10.35%		6,388	6,498	6,498	6,498	6,498	6,498	6,498	6,498	6,498	6,498	6,498	6,498	$77,868
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.85%		1,762	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	21,473
5	Total Return Component (B)			8,150	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	99,341
6	Expense Dr (Cr)															
	a. 5020011 Ammonia expense			253,398	218,073	257,348	236,362	202,109	630,288	514,636	567,914	535,720	535,485	436,209	586,378	4,852,920
	c. 5020012 Limestone Expense			55,145	50,765	124,613	114,175	74,193	195,891	190,429	311,904	304,004	302,984	238,229	327,001	2,292,336
	d. 5020003 Gypsum Disposal/Sale			380,324	359,321	569,398	539,709	425,966	772,168	756,530	1,102,194	1,079,720	1,076,818	892,605	1,145,142	9,100,000
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			691,870	628,160	951,359	890,247	702,271	1,498,347	1,461,595	1,982,012	1,919,443	1,915,287	1,567,046	2,057,521	16,245,257
8	Total System Recoverable Expenses (Lines 5 + 7)			700,019	636,450	959,649	898,537	710,561	1,506,637	1,469,986	1,990,302	1,927,733	1,923,577	1,575,336	2,065,811	16,344,598
	a. Recoverable costs allocated to Energy			700,019	636,450	959,649	898,537	710,561	1,506,637	1,469,986	1,990,302	1,927,733	1,923,577	1,575,336	2,065,811	16,344,598
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95890	0.95990	
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)			677,479	612,392	927,309	868,436	687,881	1,460,835	1,411,627	1,906,510	1,845,804	1,839,324	1,505,864	1,983,774	15,707,035
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)			$ 677,479	$ 612,392	$ 927,309	$ 868,436	$ 687,881	$ 1,460,835	$ 1,411,627	$ 1,906,510	$ 1,845,804	$ 1,839,324	$ 1,505,864	$ 1,983,774	$ 15,707,035

Notes:
(A) Line 8 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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 Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. *Expenditures/Additions*			1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	$20,000
	b. Clearings to Plant			0	0	5,000	0	0	5,000	0	0	5,000	0	0	5,000	
	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		$30,146	30,146	30,146	35,146	35,146	35,146	40,146	40,146	40,146	45,146	45,146	45,146	50,146	
3	Less: Accumulated Depreciation		(852)	(960)	(1,068)	(1,185)	(1,311)	(1,437)	(1,572)	(1,716)	(1,860)	(2,013)	(2,174)	(2,336)	(2,505)	
4	CWIP - Non-Interest Bearing		-	1,667	3,333	(0)	1,667	3,333	(0)	1,667	3,333	(0)	1,667	3,333	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$29,294	30,853	32,411	33,961	35,502	37,042	38,574	40,097	41,619	43,133	44,639	46,144	47,641	
6	Average Net Investment			30,073	31,632	33,186	34,731	36,272	37,808	39,335	40,858	42,376	43,886	45,391	46,893	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		259	273	286	299	313	326	339	352	365	378	391	404	$3,985
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		71	75	79	83	86	90	94	97	101	104	108	111	1,099
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. *Depreciation (C)*	4.29%		108	108	117	126	126	135	144	144	153	161	161	170	1,653
	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)	0.009423		24	24	28	28	28	32	32	32	35	35	35	39	372
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			462	480	510	538	553	583	609	625	654	678	695	724	7,109
	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			462	480	510	538	553	583	609	625	654	678	695	724	7,109
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)			0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	
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)			460	478	508	534	551	581	607	623	652	676	692	721	7,083
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$460	$478	$508	$534	$551	$581	$607	$623	$652	$676	$692	$721	$7,083

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 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 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - BASE (Project 10.1)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		(14,922)	(14,953)	(14,984)	(15,325)	(15,756)	(16,187)	(16,618)	(17,049)	(17,480)	(17,911)	(18,342)	(18,773)	(19,204)	
	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)		$154,909	154,478	154,047	153,616	153,185	152,754	152,323	151,892	151,461	151,030	150,599	150,168	149,737	
	6 Average Net Investment			154,694	154,263	153,832	153,401	152,970	152,539	152,108	151,677	151,246	150,815	150,384	149,953	
	7 Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		1,334	1,330	1,326	1,323	1,319	1,315	1,311	1,308	1,304	1,300	1,297	1,293	$15,760
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		368	367	366	365	364	363	362	361	360	359	358	357	4,350
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	8 Investment Expenses															
	a. Depreciation (C)	3.06%		431	431	431	431	431	431	431	431	431	431	431	431	5,172
	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)	0.010480		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)			2,281	2,276	2,271	2,267	2,262	2,257	2,252	2,248	2,243	2,238	2,234	2,229	27,058
	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			2,281	2,276	2,271	2,267	2,262	2,257	2,252	2,248	2,243	2,238	2,234	2,229	27,058
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			2,091	2,086	2,082	2,078	2,074	2,069	2,064	2,061	2,056	2,052	2,048	2,043	24,804
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,091	$2,086	$2,082	$2,078	$2,074	$2,069	$2,064	$2,061	$2,056	$2,052	$2,048	$2,043	$24,804

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6336). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - INTERMEDIATE (10.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$76,606	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		(7,169)	(7,367)	(7,565)	(7,763)	(7,961)	(8,159)	(8,357)	(8,555)	(8,753)	(8,951)	(9,149)	(9,347)	(9,545)	
	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)		$68,837	68,639	68,441	68,243	68,045	67,847	67,649	67,451	67,253	67,055	66,857	66,659	66,461	
	6 Average Net Investment			68,738	68,540	68,342	68,144	67,946	67,748	67,550	67,352	67,154	66,956	66,758	66,560	
	7 Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		593	591	589	588	586	584	582	581	579	577	576	574	$7,000
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		163	163	162	162	162	161	161	160	160	159	159	158	1,930
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	8 Investment Expenses															
	a. Depreciation (C)	3.12%		198	198	198	198	198	198	198	198	198	198	198	198	2,376
	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)	0.009130		58	58	58	58	58	58	58	58	58	58	58	58	696
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Total System Recoverable Expenses (Lines 7 + 8)			1,012	1,010	1,007	1,006	1,004	1,001	999	997	995	992	991	988	12,002
	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			1,012	1,010	1,007	1,006	1,004	1,001	999	997	995	992	991	988	12,002
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)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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)			601	599	598	597	596	594	593	592	591	589	588	586	7,123
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$601	$599	$598	$597	$596	$594	$593	$592	$591	$589	$588	$586	$7,123

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 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 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: MODULAR COOLING TOWERS - BASE (Project 11)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		(457,179)	(468,265)	(479,351)	(490,437)	(501,523)	(512,609)	(523,695)	(534,781)	(545,867)	(556,953)	(568,039)	(579,125)	(590,211)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$207,962	196,876	185,790	174,704	163,618	152,532	141,446	130,360	119,274	108,188	97,102	86,016	74,930	
6	Average Net Investment			202,419	191,333	180,247	169,161	158,075	146,989	135,903	124,817	113,731	102,645	91,559	80,473	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		1,745	1,650	1,554	1,458	1,363	1,267	1,172	1,076	981	886	789	694	$14,634
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		481	455	429	402	376	349	323	297	270	244	218	191	4,035
	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	11,086	11,086	11,086	11,086	11,086	11,086	133,032
	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)	0.010460		581	581	581	581	581	581	581	581	581	581	581	581	6,972
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			13,893	13,772	13,650	13,527	13,406	13,283	13,162	13,040	12,918	12,796	12,674	12,552	158,673
	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			13,893	13,772	13,650	13,527	13,406	13,283	13,162	13,040	12,918	12,796	12,674	12,552	158,673
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			12,736	12,625	12,513	12,400	12,289	12,176	12,065	11,954	11,842	11,730	11,618	11,506	145,454
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$12,736	$12,625	$12,513	$12,400	$12,289	$12,176	$12,065	$11,954	$11,842	$11,730	$11,618	$11,506	$145,454

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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 2008 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 2010 - DECEMBER 2010
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	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$1,868,181	$2,602,065	$1,862,773	$2,273,032	$2,568,045	$3,100,537	$4,668,022	$3,304,359	$5,473,948	$3,443,422	$1,740,138	$1,703,100	$34,627,623
	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)	7.667%		$ 51,938	$ 99,367	$ 114,692	$ 130,368	$ 148,625	$ 168,744	$ 198,487	$ 226,158	$ 260,893	$ 294,355	$ 314,817	$ 329,256	$2,369,796
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		$9,537,848	11,406,069	14,008,134	15,870,907	18,143,939	20,731,984	23,832,521	28,500,543	31,804,902	37,278,850	40,722,272	42,462,410	44,165,511	
5	Net Investment (Lines 2 + 3 + 4)		$0	11,406,069	14,008,134	15,870,907	18,143,939	20,731,984	23,832,521	28,500,543	31,804,902	37,278,850	40,722,272	42,462,410	44,165,511	
6	Average Net Investment			5,703,034	12,707,101	14,939,520	17,007,423	19,437,961	22,282,252	26,166,532	30,152,723	34,541,876	39,000,561	41,592,341	43,313,961	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		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			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	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 (Base)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
12	Retail Energy-Related Recoverable Costs (C)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (D)			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 calculation based on proposal in PEF's rate case Dkt. 090079-EI.
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 9a x Line 10
(D) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2010 - DECEMBER 2010
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. 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 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 has conducted environmental remediations at 41 substations during 2008. PEF is currently on target to meet the schedule for substation remediations agreed to with the FDEP for 2009.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: Project expenditures are estimated to be $2,728,163 lower than originally projected. This variance is primarily due to scheduling conflicts that resulted in multiple sites being rescheduled from the first half of 2009 to the fourth quarter of 2009 and into 2010, multiple sites containing less contamination than originally projected, and recent scope changes to the remediation taking place at the West Lake Wales substation site.

Project Progress Summary:
PEF is on schedule according to the approved Substation Inspection Plan and the Substation Assessment and Remedial Action Plan.

Project Projections:
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $2,075,411.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2010 - DECEMBER 2010
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. 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:
Progress Energy has completed all TRIP inspections and has finalized its remaining targets. PEF is expecting to complete remediations on 875 distribution padmount transformer sites in 2009. All remediations have been conducted in accordance with the FDEP approved Environmental Remediation Strategy.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: Project expenditures are estimated to be $70,481 higher than originally projected.

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 the period January 2010 through December 2010 are expected to be approximately $8.9 million. Progress Energy is expecting to complete remediations on approximately 750 sites.

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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.

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.

Project Accomplishments:
During 2009 Regulatory Compliance Partners completed a regulatory gap analysis of the PIM program using the PHMSA Protocols, the Integrity Management Program Plan Revision 6 was completed and BAP personnel have participated in the design process and construction coordination for FDOT Projects at US 19 and Haines Bayshore Road, and 9th Street and Gandy Boulevard.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: O&M project expenditures are estimated to be in line with the originally projected expenses.

Project Progress Summary:
Review and updates to the integrity management plan and risk analyses continue on target. Compliance work will continue through the end of 2009, and into the future.

Project Projections:
Estimated project O&M expenditures for the period January 2010 through December 2010 are expected to be $1,218,000.

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Description and Progress Report for
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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:
The following tanks were completed and placed into service during 2009: DeBary 1, Turner 7, Turner 8 and Higgins 1. Work on Bartow 6 will commence in September 2009. Turner P-1 and P-2 piping work is anticipated to begin in September 2009 and is expected to be completed by year-end.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: There are no projected O&M project expenditures for this project in 2009.

Project Progress Summary:
PEF will continually evaluate its compliance program, including project prioritization, schedule, and technology applications.

Project Projections:
Estimated capital expenditures for the period January 2010 through December 2010 are expected to be approximately $638,000. The costs are associated with the tank upgrade work at Bartow.

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Project Title: **SO_2 and NOX Emissions**
Project No. 5

Project Description:
In accordance with Title IV of the Clean Air Act, CFR 40 Part 73 and Part 76, and Florida Statute Regulation 62-214, PEF manages the company's SO2 and NOX emissions allowance inventory for the purpose of offsetting sulfur dioxide and nitrogen oxides emissions in compliance with the Federal Acid Rain Program.

Project Accomplishments:
For purposes of compliance with an affected unit's sulfur dioxide and nitrogen oxides emissions requirements under the Acid Rain Program, the air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases of SO2 and NOX emissions allowances as well as auctions and transfers of SO2 emissions allowances.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: Project expenditures are estimated to be $19,338,701 lower than originally projected. This variance is primarily driven by actual emissions being lower than forecasted emissions due to lower power demand and fuel switching from coal-fired and oil-fired generation to gas-fired generation when economically and operationally feasible. Also, the weighted average cost – the per allowance cost at which emissions are expensed – is lower than the original projection.

Project Progress Summary:
PEF continually evaluates its compliance strategy to manage the most cost effective program and to mitigate higher gas prices which can impact our fuel mix as it relates to emissions as a result of residual oil.

Project Projections:
For the period January 2010 through December 2010 Estimated SO2 expenditures are expected to be $1,568,253 and NOX project expenditures for the period and $8,852,556, respectively. PEF also expects approximately $213,180 in amortization expense from SO2 auction proceeds in 2010.

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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.

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 and Bartow, Suwannee and Crystal River and they have been submitted and approved by the FDEP.

Project Fiscal Expenditures:
January 2009 - December 2009: Due to the vacatur, the estimated project O&M expenditures for the period January 2009 through December 2009 are projected to be $0.

Project Progress Summary:
The original baseline biological studies have been completed. Work has been suspended pending completion of additional rulemaking.

Project Projections:
Due to the vacatur, the estimated project O&M expenditures for the period January 2010 through December 2010 are projected to be $0.

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Project Title: **Integrated Clean Air Compliance Plan (CAIR)**
Project No. 7

Project Description:
Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant new restrictions on emissions of sulfur dioxide ("SO2") and nitrogen oxides ("NOx") from power plants in 28 eastern states, including Florida and the District of Columbia. The CAIR rule apportions region-wide SO2 and NOx emission reduction requirements to the individual states, and further requires each affected state to revise its State Implementation Plans ("SIP") by September 2006 to include measures necessary to achieve its emission reduction budget within the prescribed deadlines.

Project Accomplishments:
Progress Energy achieved several significant project milestones in 2009. In June 2009, we placed the Crystal River Unit 5 low NOx burners ("LNB") and selective catalytic ("SCR") system into service and in July 2009 we placed the urea to ammonia hydrolyser into service. Additionally, in December 2009, we expect to place the Unit 5 Flue Gas Desulfurization ("FGD" or "scrubber") system and chimney into service.

Project Fiscal Expenditures:
January 2009 - December 2009: PEF's expenditures for the Crystal River Projects in 2009 will be approximately $215.8 million, which is in line with the original projection expenditures of $215.9 million.

Project Progress Summary:
PEF will continue to regularly track project expenditures against the detailed project scopes to ensure that PEF receives what it contracted for and that any scope changes are properly evaluated and documented. We also will continue to conduct regularly scheduled meetings with the primary contractors and senior management to maintain supervision of the project, to ensure that management remains fully informed, and to ensure that management expectations are communicated to the outside vendors and the project team.

Project Projections:
Estimated project expenditures for the period January 2010 through December 2010 are expected to be approximately $58.1 million relating to the SCR and FGD systems at both Crystal River Units 4 and 5.

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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 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:
Sampling of existing monitoring wells continues as required by the reissued Industrial Wastewater Permit. Discussions are continuing with FDEP relative to an acceptable strategic plan.

Project Fiscal Expenditures:
January 2009 - December 2009: O&M costs are expected to be $77,669 lower than originally forecasted as work continues with FDEP to establish an arsenic compliance plan and schedule.

Project Progress Summary:
PEF will continually evaluate analytical results and maintain ongoing communication with FDEP regarding compliance strategies.

Project Projections:
Progress Energy continues to work with the Florida Department of Environmental Protection to comply with the terms of the renewed industrial wastewater permit for the Crystal River Energy Complex (January 9, 2007) and the modified Conditions of Certification (November 29, 2007; and June 5, 2009). Given this level of uncertainly regarding this program, PEF is not projecting any costs specific to the Arsenic program in 2010.

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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 local ordinances within their jurisdiction. To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County and the City of Mexico Beach in Bay 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 ordinances.

Project Accomplishments:
PEF has worked with Franklin County to determine the most cost-effective compliance measures for affected lighting on St. George Island. Compliance measures that have been performed include retrofitting existing streetlights, monitoring them for effectiveness, and making modifications to the retrofitted lights where applicable. Project studies are ongoing with University of Florida and are expected to continue through 2010.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: Project revenue requirements are estimated to be slightly lower than the original 2009 projection of $7202.

Project Progress Summary:
PEF is on schedule with the activities identified for this program.

Project Projections:
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $1,800 in O&M costs and $20,000 in capital expenditures to ensure ongoing compliance with sea turtle ordinances.

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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. The necessary work was performed in 2006.

Project Accomplishments:
Work on Crystal River and Bartow USTs was completed in the fourth quarter 2006.

Project Fiscal Expenditures:
$0 was projected to be spent in 2009.

Project Projections:
No project capital expenditures are anticipated for the period January 2010 through December 2010.

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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:
Project O&M costs of approximately $3.3 million per year are expected, including unit mobilization and setup, rental fees, de-mobilization and fill replacement.

Project Progress Summary:
Modular cooling towers began operation in June 2006 and have successfully minimized de-rates of Units 1 and 2.

Project Projections:
Estimated project expenditures are expected to be approximately $3.3 million for the period January 2010 thru December 2010.

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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 that is currently being addressed in the short term by the Modular Cooling Towers approved in Docket # 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 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.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: PEF is projecting capital expenditures to be $2,440,619 lower for this project in 2009 than originally forecast. This variance is mainly attributable to the refinement of project costs reflecting design changes due to anticipated scope reductions and associated procurement requirements.

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:
Estimated project expenditures are expected to be approximately $34.6 million for the period January 2010 thru December 2010.

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Project Title: **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.

Project Accomplishments:
During 2009, Progress Energy joined The Climate Registry and has submitted the 2008 GHG inventory.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: O&M project expenditures are estimated to be $42,680 less than originally projected. This variance is the result of preparing the inventory report with internal resources rather than external consultants during the first two quarters of the year. A third party consultant will be hired for verification of the report, as required by the Climate Registry, and those are the expenses now projected for 2009.

Project Progress Summary:
The 2008 GHG inventory is currently verification ready and a kick-off meeting for verification was held in July 2009.

Project Projections:
Estimated project expenditures are expected to be approximately $22,500 for the period January 2010 thru December 2010.

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Project Title: **Mercury Total Daily Maximum Loads Monitoring**
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) has completed the literature review on mercury deposition in Florida, this document has been sent to the Division of Air Resource Management and the TMDL team for review. In addition, the Mercury Task Force has met with both the Division of Air Resource Management in the TMDL team to discuss the review. AER has initiated the Florida mercury deposition modeling for the Division of Air Resource Management, it is anticipating this work will be done by the end of 2009.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: PEF expects that total O&M project expenditures for the year will be approximately $92,164.

Project Progress Summary:
The Florida Electric Coordinating Group (FCG) Mercury task force continues to meet with the state as the changes in the program evolve. In 2009 PEF contracted with private contractor to develop a conceptual model, and continue to that work into 2010.

Project Projections:
Estimated project expenditures are expected to be approximately $36,077 for the period January 2010 thru December 2010.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % by Rate Class
JANUARY 2010 - DECEMBER 2010

Form 42-6P

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrs/(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	0.494	18,303,702	4,229.68	0.361	0.9364356	19,546,141	4,516.79	19,546,141	6,160.9	50.554%	62.735%	61.798%	63.795%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.695	1,120,052	183.97	0.423	0.9364356	1,196,080	196.48	1,196,080	322.8	3.094%	2.729%	2.757%	3.332%
Primary	0.695	7,294	1.20	0.423	0.9682000	7,534	1.24	7,534	2.0	0.019%	0.017%	0.017%	0.021%
Transmission	0.695	3,574	0.59	0.423	0.9782000	3,654	0.60	0	0.0	0.009%	0.008%	0.008%	0.000%
										3.122%	2.754%	2.783%	3.353%
General Service													
GS-2 Secondary	1.000	86,214	9.84	1.000	0.9364356	92,066	10.51	92,066	10.5	0.238%	0.146%	0.153%	0.108%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.785	11,831,271	1,720.51	0.612	0.9364356	12,634,367	1,837.30	12,634,367	2,356.7	32.677%	25.519%	26.068%	24.324%
Primary	0.785	2,253,073	327.64	0.612	0.9682000	2,327,074	338.40	2,327,074	434.1	6.019%	4.700%	4.802%	4.480%
Transmission	0.785	0	0.00	0.612	0.9782000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.546	0	0.00	0.207	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.546	16,205	1.20	0.207	0.9782000	16,566	1.22	0	0.0	0.043%	0.017%	0.019%	0.000%
Transm Del/ Primary Mtr	1.546	4,336	0.32	0.207	0.9682000	4,480	0.33	0	0.0	0.012%	0.005%	0.005%	0.000%
										38.750%	30.240%	30.895%	28.804%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	0.935	0	0.00	0.592	0.9364356	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	0.935	168,726	20.60	0.592	0.9682000	174,268	21.26	174,268	33.6	0.451%	0.298%	0.307%	0.347%
SS-3 Primary	0.451	9,545	2.42	0.047	0.9682000	9,859	2.50	9,859	23.9	0.025%	0.035%	0.034%	0.247%
										0.476%	0.330%	0.341%	0.594%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.983	98,446	11.43	0.768	0.9364356	105,128	12.21	105,128	15.6	0.272%	0.170%	0.177%	0.161%
Sec Del/Primary Mtr	0.983	4,366	0.51	0.768	0.9682000	4,509	0.52	4,509	0.7	0.012%	0.007%	0.008%	0.007%
Primary Del / Primary Mtr	0.983	1,396,962	162.23	0.768	0.9682000	1,442,844	167.56	1,442,844	214.5	3.732%	2.327%	2.435%	2.214%
Primary Del / Transm Mtr	0.983	16,975	1.97	0.768	0.9782000	17,353	2.02	17,353	2.6	0.045%	0.028%	0.029%	0.027%
Transm Del/ Transm Mtr	0.983	257,555	29.91	0.768	0.9782000	263,295	30.58	0	0.0	0.681%	0.425%	0.444%	0.000%
Transm Del/ Primary Mtr	0.983	275,801	32.03	0.768	0.9682000	284,860	33.08	0	0.0	0.737%	0.459%	0.481%	0.000%
SS-2 Primary	0.929	0	0.00	0.447	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.929	81,348	10.00	0.447	0.9782000	83,181	10.22	0	0.0	0.215%	0.142%	0.148%	0.000%
Transm Del/ Primary Mtr	0.929	67,833	8.31	0.447	0.9682000	69,854	8.58	0	0.0	0.181%	0.119%	0.124%	0.000%
										5.674%	3.677%	3.846%	2.408%
Lighting													
LS-1 (Secondary)	5.151	356,890	7.91	0.479	0.9364356	381,115	8.45	381,115	90.8	0.986%	0.117%	0.184%	0.937%
		36,359,970	6,762.26			38,664,208	7,199.84	37,936,339	9,688.6	100.000%	100.000%	100.000%	100.000%

Notes:
(1) Average 12CP load factor based on load research study filed July 31, 2009
(2) Projected kWh sales for the period January 2009 to December 2009
(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 2008
(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 8/ Total Column 8
(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 the Energy & Demand Allocation % by Rate Class
JANUARY 2010 - DECEMBER 2010

Form 42-6P

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)/(8760hrsx(4))	(9) mWh Sales at Source Energy Allocator (%)	(10) 12CP Demand Transmission Allocator (%)	(11) 12CP & 50% AD Demand Allocator (%)	(12) NCP Distribution Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	0.494	18,303,702	4,229.68	0.361	0.9364356	19,546,141	4,516.79	19,546,141	6,180.9	50.554%	62.735%	56.644%	63.795%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.695	1,120,052	183.97	0.423	0.9364356	1,196,080	196.46	1,196,080	322.8	3.094%	2.729%	2.911%	3.332%
Primary	0.695	7,294	1.20	0.423	0.9682000	7,534	1.24	7,534	2.0	0.019%	0.017%	0.018%	0.021%
Transmission	0.695	3,574	0.59	0.423	0.9782000	3,654	0.60	0	0.0	0.009%	0.008%	0.009%	0.000%
										3.122%	2.754%	2.938%	3.353%
General Service													
GS-2 Secondary	1.000	86,214	9.84	1.000	0.9364356	92,066	10.51	92,066	10.5	0.238%	0.146%	0.192%	0.108%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.765	11,831,271	1,720.51	0.612	0.9364356	12,634,387	1,837.30	12,634,367	2,356.7	32.677%	25.519%	29.098%	24.324%
Primary	0.765	2,253,073	327.64	0.612	0.9682000	2,327,074	338.40	2,327,074	434.1	6.019%	4.700%	5.359%	4.480%
Transmission	0.765	0	0.00	0.612	0.9782000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.546	0	0.00	0.207	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.546	16,205	1.20	0.207	0.9782000	16,566	1.22	0	0.0	0.043%	0.017%	0.030%	0.000%
Transm Del/ Primary Mtr	1.546	4,338	0.32	0.207	0.9682000	4,480	0.33	0	0.0	0.012%	0.005%	0.008%	0.000%
										38.750%	30.240%	34.495%	28.804%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	0.935	0	0.00	0.592	0.9364356	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	0.935	166,726	20.80	0.592	0.9682000	174,268	21.28	174,268	33.6	0.451%	0.296%	0.373%	0.347%
SS-3 Primary	0.451	9,545	2.42	0.047	0.9682000	9,859	2.50	9,859	23.9	0.025%	0.035%	0.030%	0.247%
										0.476%	0.330%	0.403%	0.594%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.983	98,446	11.43	0.768	0.9364356	105,128	12.21	105,128	15.6	0.272%	0.170%	0.221%	0.161%
Sec Del/Primary Mtr	0.983	4,366	0.51	0.768	0.9682000	4,509	0.52	4,509	0.7	0.012%	0.007%	0.009%	0.007%
Primary Del / Primary Mtr	0.983	1,396,962	162.23	0.768	0.9682000	1,442,844	167.56	1,442,844	214.5	3.732%	2.327%	3.029%	2.214%
Primary Del / Transm Mtr	0.983	16,975	1.97	0.768	0.9782000	17,353	2.02	17,353	2.6	0.045%	0.028%	0.036%	0.027%
Trarism Del/ Transm Mtr	0.983	257,555	29.91	0.768	0.9782000	263,295	30.58	0	0.0	0.681%	0.425%	0.553%	0.000%
Transm Del/ Primary Mtr	0.983	275,801	32.03	0.768	0.9682000	284,880	33.08	0	0.0	0.737%	0.459%	0.598%	0.000%
SS-2 Primary	0.929	0	0.00	0.447	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.929	61,348	10.00	0.447	0.9782000	63,161	10.22	0	0.0	0.215%	0.142%	0.179%	0.000%
Transm Del/ Primary Mtr	0.929	67,633	8.31	0.447	0.9682000	69,854	8.58	0	0.0	0.181%	0.119%	0.150%	0.000%
										5.874%	3.677%	4.776%	2.408%
Lighting													
LS-1 (Secondary)	5.151	356,890	7.91	0.479	0.9364356	381,115	8.45	381,115	90.8	0.986%	0.117%	0.552%	0.937%
		36,359,970	6,762.26			38,664,208	7,199.84	37,938,339	9,686.6	100.000%	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2009
(2) Projected kWh sales for the period January 2009 to December 2009
(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 2008
(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 50% + Column 10 x 50%
(12) Column 8/ Total Column 8

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % by Rate Class
JANUARY 2010 - DECEMBER 2010

Form 42-6P

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrs/(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 & 25% AD Demand Allocator (%)	(12) NCP Distribution Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	0.494	16,303,702	4,229.66	0.361	0.9364356	19,546,141	4,518.79	19,546,141	6,180.9	50.554%	62.735%	59.689%	63.795%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.695	1,120,052	183.97	0.423	0.9364356	1,196,080	196.46	1,196,080	322.8	3.094%	2.729%	2.820%	3.332%
Primary	0.695	7,294	1.20	0.423	0.9682000	7,534	1.24	7,534	2.0	0.019%	0.017%	0.018%	0.021%
Transmission	0.695	3,574	0.59	0.423	0.9782000	3,654	0.60	0	0.0	0.009%	0.008%	0.009%	0.000%
										3.122%	2.754%	2.846%	3.353%
General Service													
GS-2 Secondary	1.000	86,214	9.84	1.000	0.9364356	92,066	10.51	92,066	10.5	0.238%	0.146%	0.169%	0.108%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.785	11,831,271	1,720.51	0.612	0.9364356	12,634,367	1,837.30	12,634,367	2,356.7	32.677%	25.519%	27.308%	24.324%
Primary	0.785	2,253,073	327.64	0.612	0.9682000	2,327,074	338.40	2,327,074	434.1	6.019%	4.700%	5.030%	4.480%
Transmission	0.785	0	0.00	0.612	0.9782000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.546	0	0.00	0.207	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.546	16,205	1.20	0.207	0.9782000	16,566	1.22	0	0.0	0.043%	0.017%	0.023%	0.000%
Transm Del/ Primary Mtr	1.546	4,338	0.32	0.207	0.9682000	4,480	0.33	0	0.0	0.012%	0.005%	0.006%	0.000%
										38.750%	30.240%	32.368%	28.804%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	0.935	0	0.00	0.592	0.9364356	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	0.935	168,726	20.60	0.592	0.9682000	174,268	21.26	174,268	33.6	0.451%	0.296%	0.334%	0.347%
SS-3 Primary	0.451	9,545	2.42	0.047	0.9682000	9,859	2.50	9,859	23.9	0.025%	0.035%	0.032%	0.247%
										0.476%	0.330%	0.367%	0.594%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.983	98,446	11.43	0.768	0.9364356	105,128	12.21	105,128	15.6	0.272%	0.170%	0.195%	0.161%
Sec Del/Primary Mtr	0.983	4,366	0.51	0.768	0.9682000	4,509	0.52	4,509	0.7	0.012%	0.007%	0.008%	0.007%
Primary Del / Primary Mtr	0.983	1,398,962	162.23	0.768	0.9682000	1,442,844	167.58	1,442,844	214.5	3.732%	2.327%	2.678%	2.214%
Primary Del / Transm Mtr	0.983	16,975	1.97	0.768	0.9782000	17,353	2.02	17,353	2.6	0.045%	0.028%	0.032%	0.027%
Transm Del/ Transm Mtr	0.983	257,555	29.91	0.768	0.9782000	263,295	30.58	0	0.0	0.681%	0.425%	0.488%	0.000%
Transm Del/ Primary Mtr	0.983	275,801	32.03	0.768	0.9682000	284,860	33.08	0	0.0	0.737%	0.459%	0.529%	0.000%
SS-2 Primary	0.929	0	0.00	0.447	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.929	81,348	10.00	0.447	0.9782000	83,161	10.22	0	0.0	0.215%	0.142%	0.160%	0.000%
Transm Del/ Primary Mtr	0.929	67,633	8.31	0.447	0.9682000	69,854	8.58	0	0.0	0.181%	0.119%	0.135%	0.000%
										5.874%	3.677%	4.226%	2.408%
Lighting													
LS-1 (Secondary)	5.151	356,890	7.91	0.479	0.9364356	381,115	8.45	381,115	90.8	0.986%	0.117%	0.334%	0.937%
		36,359,970	6,762.26			38,664,208	7,199.84	37,938,339	9,888.6	100.000%	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2009
(2) Projected kWh sales for the period January 2009 to December 2009
(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 2008
(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 8/ Total Column 8
(10) Column 7/ Total Column 7
(11) Column 9 x 25% + Column 10 x 25%
(12) Column 8/ Total Column 8

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-3)
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PROGRESS ENERGY FLORIDA

Form 42-7P

Environmental Cost Recovery Clause (ECRC)

Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class

JANUARY 2010 - DECEMBER 2010

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Allocator (%)	(3) 12CP & 50% 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	50.554%	62.735%	56.644%	63.795%	$110,820,902	$210,111	$5,609,708	$3,205,729	$119,846,450	18,303,702	0.655
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,120,052	0.647
Primary										7,221	0.641
Transmission										3,503	0.634
TOTAL GS	3.122%	2.754%	2.938%	3.353%	$6,844,853	$9,224	$294,804	$168,291	$7,315,172	1,130,775	
General Service											
GS-2 Secondary	0.238%	0.146%	0.192%	0.108%	$521,988	$456	$9,539	$10,869	$542,884	86,214	0.630
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										11,831,271	0.636
Primary										2,234,837	0.630
Transmission										15,881	0.623
TOTAL GSD	38.750%	30.240%	34.495%	28.804%	$84,946,323	$101,281	$2,532,844	$1,952,236	$89,532,684	14,081,989	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	0.635
Primary										176,488	0.629
Transmission										-	0.622
TOTAL CS	0.476%	0.330%	0.403%	0.594%	$1,043,942	$1,106	$52,231	$22,819	$1,120,097	176,488	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										98,446	0.615
Primary										1,727,314	0.609
Transmission										348,760	0.603
TOTAL IS	5.874%	3.677%	4.776%	2.408%	$12,875,936	$12,316	$211,777	$270,266	$13,370,295	2,174,521	
Sub-Total Curtailable/Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										98,446	0.616
Primary										1,903,803	0.610
Transmission										348,760	0.604
TOTAL IS	6.350%	4.008%	5.179%	3.002%	$13,919,877	$13,422	$264,008	$293,085	$14,490,392	2,351,009	
Lighting											
LS-1 Secondary	0.986%	0.117%	0.552%	0.937%	$2,160,813	$393	$82,434	$31,212	$2,274,852	366,890	0.637
	100.000%	100.000%	100.000%	100.000%	$219,214,756	$334,920	$8,793,336	$5,859,422	$234,002,435	36,310,579	0.644

Notes:

(1) From Form 42-6P 50%, Column 9
(2) From Form 42-6P 50%, Column 10
(3) From Form 42-6P 50%, Column 11
(4) From Form 42-6P 50%, 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 effective voltage level for the period January 2009 to December 2009
(11) Column 7/ Column 8 x 100

PROGRESS ENERGY FLORIDA

Form 42-7P

Environmental Cost Recovery Clause (ECRC)

Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class

JANUARY 2010 - DECEMBER 2010

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Allocator (%)	(3) 12CP & 25% 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	50.554%	52.736%	59.689%	63.795%	$110,820,902	$210,111	$5,609,708	$3,378,073	$120,018,794	18,303,702	0.656
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,120,052	0.646
Primary										7,221	0.640
Transmission										3,503	0.633
TOTAL GS	3.122%	2.754%	2.646%	3.353%	$6,844,853	$9,224	$294,804	$161,081	$7,309,962	1,130,776	
General Service											
GS-2 Secondary	0.238%	0.146%	0.169%	0.108%	$521,988	$489	$9,539	$9,565	$541,580	86,214	0.628
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										11,831,271	0.636
Primary										2,234,837	0.629
Transmission										15,881	0.622
TOTAL GSD	38.750%	30.240%	32.368%	28.804%	$84,946,323	$101,281	$2,532,844	$1,681,833	$89,412,281	14,081,989	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	0.633
Primary										176,488	0.627
Transmission										-	0.620
TOTAL CS	0.476%	0.330%	0.367%	0.594%	$1,043,942	$1,106	$52,231	$20,753	$1,118,031	176,488	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										98,446	0.613
Primary										1,727,314	0.607
Transmission										348,760	0.601
TOTAL IS	5.874%	3.877%	4.226%	2.408%	$12,875,936	$12,316	$211,777	$239,192	$13,339,221	2,174,521	
Sub-Total Curtailable/Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										98,446	0.615
Primary										1,903,803	0.609
Transmission										348,760	0.603
TOTAL IS	6.350%	4.006%	4.593%	3.002%	$13,919,877	$13,422	$264,008	$259,944	$14,457,252	2,351,009	
Lighting											
LS-1 Secondary	0.986%	0.117%	0.334%	0.937%	$2,160,813	$393	$82,434	$18,926	$2,262,565	356,890	0.634
	100.000%	100.000%	100.000%	100.000%	$219,214,756	$334,920	$8,793,336	$5,659,422	$234,002,435	36,310,579	0.644

Notes:

(1) From Form 42-6P 25%, Column 9
(2) From Form 42-6P 25%, Column 10
(3) From Form 42-6P 25%, Column 11
(4) From Form 42-6P 25%, 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 effective voltage level for the period January 2009 to December 2009
(11) Column 7/ Column 8 x 100

PROGRESS ENERGY FLORIDA

Form 42-7P

Environmental Cost Recovery Clause (ECRC)

Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class

JANUARY 2010 - DECEMBER 2010

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission 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	50.554%	62.735%	61.798%	63.795%	$110,820,902	$210,111	$5,609,708	$3,497,389	$120,138,109	18,303,702	0.656
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,120,052	0.646
Primary										7,221	0.640
Transmission										3,503	0.633
TOTAL GS	3.122%	2.754%	2.783%	3.353%	$6,844,853	$9,224	$294,804	$157,474	$7,306,355	1,130,776	
General Service											
GS-2 Secondary	0.238%	0.146%	0.153%	0.108%	$521,988	$489	$9,539	$8,662	$540,678	86,214	0.627
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										11,831,271	0.634
Primary										2,234,837	0.628
Transmission										15,881	0.621
TOTAL GSD	38.750%	30.240%	30.895%	28.804%	$84,946,323	$101,291	$2,532,844	$1,748,477	$89,328,925	14,081,989	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	0.633
Primary										176,488	0.627
Transmission										-	0.620
TOTAL CS	0.476%	0.330%	0.341%	0.594%	$1,043,942	$1,106	$52,231	$19,322	$1,116,601	176,488	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										98,448	0.612
Primary										1,727,314	0.606
Transmission										348,760	0.600
TOTAL IS	5.874%	3.677%	3.846%	2.406%	$12,875,936	$12,316	$211,777	$217,678	$13,317,707	2,174,521	
Sub-Total Curtailable/Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										98,448	0.614
Primary										1,903,803	0.608
Transmission										348,760	0.602
TOTAL IS	6.350%	4.008%	4.186%	3.002%	$13,919,877	$13,422	$264,008	$237,001	$14,434,308	2,351,009	
Lighting											
LS-1 Secondary	0.986%	0.117%	0.184%	0.937%	$2,160,813	$393	$82,434	$10,420	$2,254,059	356,890	0.632
	100.000%	100.000%	100.000%	100.000%	$219,214,756	$334,920	$8,793,336	$5,659,422	$234,002,435	36,310,579	0.644

Notes:

(1) From Form 42-6P 12 & 1/13, Column 9
(2) From Form 42-6P 12 & 1/13, Column 10
(3) From Form 42-6P 12 & 1/13, Column 11
(4) From Form 42-6P 12 & 1/13, 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 effective voltage level for the period January 2009 to December 2009
(11) Column 7/ Column 8 x 100

Witness: T.G. Foster
Exibit__(TGF-4)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2010 - DECEMBER 2010
Calculation of the Projected Period Amount
January through December 2010
DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 27
COMPANY Progress Energy Florida, Inc.
WITNESS Thomas G. Foster (TGF-4)
DATE 11/02/09

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2010 - DECEMBER 2010

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		($5,497)	(5,586)	(5,675)	(5,764)	(5,853)	(5,942)	(6,031)	(6,120)	(6,209)	(6,298)	(6,387)	(6,476)	(6,565)	
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)		$28,456	28,367	28,278	28,189	28,100	28,011	27,922	27,833	27,744	27,655	27,566	27,477	27,388	
6	Average Net Investment			28,411	28,322	28,233	28,144	28,055	27,966	27,877	27,788	27,699	27,610	27,521	27,432	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		245	244	243	243	242	241	240	240	239	238	237	237	$2,889
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		68	67	67	67	67	66	66	66	66	66	65	65	796
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.13%		89	89	89	89	89	89	89	89	89	89	89	89	1,068
	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	0.008907		25	25	25	25	25	25	25	25	25	25	25	25	300
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			427	425	424	424	423	421	420	420	419	418	416	416	5,053
	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			427	425	424	424	423	421	420	420	419	418	416	416	5,053

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	
3	Less: Accumulated Depreciation		($521,476)	(533,080)	(544,385)	(555,740)	(567,095)	(578,450)	(589,805)	(601,160)	(612,515)	(623,870)	(635,225)	(646,580)	(657,935)	
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)		$2,119,361	2,107,808	2,096,251	2,084,696	2,073,141	2,062,186	2,050,831	2,039,476	2,028,121	2,016,766	2,005,411	1,994,056	1,982,701	
6	Average Net Investment			2,113,284	2,101,929	2,090,574	2,079,219	2,067,864	2,056,509	2,045,154	2,033,799	2,022,444	2,011,089	1,999,734	1,988,379	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		18,220	18,122	18,024	17,926	17,828	17,731	17,633	17,535	17,437	17,339	17,241	17,143	$212,179
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		5,024	4,997	4,970	4,943	4,916	4,889	4,862	4,835	4,808	4,781	4,754	4,727	58,506
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.16%		11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	136,260
	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	0.008907		1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	23,520
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			36,559	36,434	36,309	36,184	36,059	35,935	35,810	35,685	35,560	35,435	35,310	35,185	430,465
	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			36,559	36,434	36,309	36,184	36,059	35,935	35,810	35,685	35,560	35,435	35,310	35,185	430,465

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2010 - DECEMBER 2010

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$966,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	
3	Less: Accumulated Depreciation		(538,236)	(42,128)	(46,020)	(49,912)	(53,804)	(57,696)	(61,588)	(65,480)	(69,372)	(73,264)	(77,156)	(81,048)	(84,940)	
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)		$366,911	863,019	859,127	855,235	851,343	847,451	843,559	839,667	835,775	831,883	827,991	824,099	820,207	
6	Average Net Investment			864,965	861,073	857,181	853,289	849,397	845,505	841,613	837,721	833,829	829,937	826,045	822,153	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		7,467	7,424	7,390	7,357	7,323	7,290	7,258	7,223	7,189	7,155	7,122	7,086	$87,274
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		2,056	2,047	2,038	2,029	2,019	2,010	2,001	1,992	1,982	1,973	1,964	1,955	24,066
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.16%		3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	46,704
	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	0.008907		672	672	672	672	672	672	672	672	672	672	672	672	8,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,077	14,035	13,992	13,950	13,906	13,864	13,821	13,779	13,735	13,692	13,650	13,607	166,108
	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			14,077	14,035	13,992	13,950	13,906	13,864	13,821	13,779	13,735	13,692	13,650	13,607	166,108

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(In Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	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. Other														
2	Plant-in-Service/Depreciation Base	$1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	
3	Less: Accumulated Depreciation	(35,776)	(46,879)	(57,982)	(69,085)	(80,188)	(91,291)	(102,394)	(113,497)	(124,600)	(135,703)	(146,806)	(157,909)	(169,012)	
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)	$1,918,723	1,907,620	1,896,517	1,885,414	1,874,311	1,863,208	1,852,105	1,841,002	1,829,899	1,818,796	1,807,693	1,796,590	1,785,487	
6	Average Net Investment		1,913,171	1,902,068	1,890,965	1,879,862	1,868,759	1,857,656	1,846,553	1,835,450	1,824,347	1,813,244	1,802,141	1,791,038	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	10.35%	16,495	16,399	16,303	16,208	16,112	16,016	15,920	15,825	15,729	15,633	15,537	15,442	$191,819
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.57%	4,549	4,522	4,496	4,469	4,443	4,417	4,390	4,364	4,337	4,311	4,285	4,259	52,841
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	6.82%	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	133,236
	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	0.009278	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	18,120
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		33,657	33,534	33,412	33,290	33,168	33,046	32,923	32,802	32,679	32,557	32,435	32,313	395,616
	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		33,657	33,534	33,412	33,290	33,168	33,046	32,923	32,802	32,679	32,557	32,435	32,313	395,616

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(In Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments		$155,000	$280,000	$223,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$638,000
	a. Expenditures/Additions		0	0	1,513,040	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														
2	Plant-in-Service/Depreciation Base	$163,699	163,699	163,699	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	
3	Less: Accumulated Depreciation	(38,659)	(35,184)	(36,704)	(38,468)	(44,096)	(50,824)	(58,652)	(67,580)	(67,108)	(72,636)	(78,164)	(83,692)	(89,220)	
4	CWIP - Non-Interest Bearing	875,040	1,030,040	1,296,040	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$963,659	1,147,545	1,407,035	1,627,271	1,621,743	1,615,915	1,610,087	1,605,158	1,599,631	1,594,103	1,588,575	1,583,047	1,577,518	
6	Average Net Investment		1,055,300	1,277,290	1,517,153	1,624,607	1,618,979	1,613,451	1,607,823	1,602,395	1,596,867	1,591,339	1,585,811	1,580,283	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	10.35%	9,228	11,012	13,080	14,006	13,958	13,911	13,863	13,815	13,768	13,720	13,672	13,625	$157,858
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.57%	2,545	3,037	3,607	3,862	3,849	3,836	3,823	3,810	3,797	3,783	3,770	3,757	43,476
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	3.98%	510	510	2,764	5,628	5,628	5,628	5,628	5,628	5,628	5,628	5,628	5,628	53,938
	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	0.009139	117	117	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268	12,914
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		12,400	14,676	20,719	24,764	24,703	24,643	24,582	24,421	24,361	24,299	24,238	24,178	267,584
	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		12,400	14,676	20,719	24,764	24,703	24,643	24,582	24,421	24,361	24,299	24,238	24,178	267,584

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(8,847)	(8,706)	(8,865)	(9,024)	(9,183)	(9,342)	(9,501)	(9,660)	(9,819)	(9,978)	(10,137)	(10,296)	(10,455)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$24,246	24,386	24,227	24,068	23,909	23,750	23,591	23,432	23,273	23,114	22,955	22,796	22,637	
6	Average Net Investment			24,466	24,306	24,147	23,988	23,829	23,670	23,511	23,352	23,193	23,034	22,875	22,716	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		211	210	208	207	205	204	203	201	200	199	197	196	$2,441
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.65%		56	56	57	57	57	56	56	56	55	55	54	54	673
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.77%		159	159	159	159	159	159	159	159	159	159	159	159	1,908
	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	0.010489		29	29	29	29	29	29	29	29	29	29	29	29	348
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			457	456	453	452	450	448	447	445	443	442	439	438	5,370
	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			457	456	453	452	450	448	447	445	443	442	439	438	5,370

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(176,133)	(180,247)	(204,371)	(218,495)	(232,619)	(246,743)	(260,867)	(274,991)	(289,115)	(303,239)	(317,363)	(331,487)	(345,611)	
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)		$1,485,541	1,471,417	1,457,293	1,443,169	1,429,045	1,414,921	1,400,797	1,386,673	1,372,549	1,358,425	1,344,301	1,330,177	1,316,053	
6	Average Net Investment			1,478,479	1,464,355	1,450,231	1,436,107	1,421,983	1,407,859	1,393,735	1,379,611	1,365,487	1,351,363	1,337,239	1,323,115	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		12,747	12,625	12,503	12,382	12,260	12,138	12,016	11,895	11,773	11,651	11,529	11,407	$144,826
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.65%		3,515	3,482	3,448	3,414	3,381	3,347	3,314	3,280	3,246	3,213	3,179	3,146	39,965
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	16.20%		14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	169,488
	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	0.007746		1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	12,864
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			31,458	31,303	31,147	30,992	30,837	30,681	30,526	30,371	30,215	30,060	29,904	29,749	367,243
	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			31,458	31,303	31,147	30,992	30,837	30,681	30,526	30,371	30,215	30,060	29,904	29,749	367,243

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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*		(21,161)	(22,096)	(23,031)	(23,966)	(24,901)	(25,836)	(26,771)	(27,706)	(28,641)	(29,576)	(30,511)	(31,446)	(32,381)	
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)		$157,777	156,842	155,907	154,972	154,037	153,102	152,167	151,232	150,297	149,362	148,427	147,492	146,557	
6	Average Net Investment			157,309	156,374	155,439	154,504	153,569	152,634	151,699	150,764	149,829	148,894	147,959	147,024	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		1,356	1,348	1,340	1,332	1,324	1,316	1,308	1,300	1,292	1,284	1,276	1,268	$15,744
	b. *Debt Component (Line 6 x 2.57% x 1/12)*	*2.57%*		*374*	*372*	*370*	*367*	*365*	*363*	*361*	*358*	*356*	*354*	*352*	*350*	4,343
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.27%		935	935	935	935	935	935	935	935	935	935	935	935	11,220
	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	0.004750		131	131	131	131	131	131	131	131	131	131	131	131	1,572
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,796	2,788	2,776	2,765	2,755	2,745	2,735	2,724	2,714	2,704	2,694	2,684	32,879
	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			2,796	2,788	2,776	2,765	2,755	2,745	2,735	2,724	2,714	2,704	2,694	2,684	32,879

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(45,896)	(47,803)	(50,210)	(52,517)	(54,824)	(57,131)	(59,438)	(61,745)	(64,052)	(66,359)	(68,666)	(70,973)	(73,280)	
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)		684,399	682,493	680,086	677,779	675,472	673,165	670,858	668,551	666,244	663,937	661,629	659,323	657,016	
6	Average Net Investment			683,446	681,289	678,932	676,625	674,318	672,011	669,704	667,397	665,090	662,783	660,476	658,169	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		5,893	5,873	5,854	5,834	5,814	5,794	5,774	5,754	5,734	5,714	5,694	5,675	$69,407
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.57%		1,626	1,620	1,614	1,608	1,602	1,596	1,592	1,587	1,581	1,576	1,570	1,565	19,140
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.78%		2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	27,684
	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	0.009130		556	556	556	556	556	556	556	556	556	556	556	556	6,672
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,381	10,356	10,331	10,306	10,280	10,255	10,229	10,204	10,178	10,153	10,127	10,103	122,903
	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			10,381	10,356	10,331	10,306	10,280	10,255	10,229	10,204	10,178	10,153	10,127	10,103	122,903

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(84,360)	(87,998)	(91,636)	(95,277)	(98,916)	(102,556)	(106,194)	(109,833)	(113,472)	(117,111)	(120,750)	(124,389)	(128,028)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$952,839	949,200	945,561	941,922	938,283	934,644	931,005	927,366	923,727	920,088	916,449	912,810	909,171	
6	Average Net Investment			951,020	947,381	943,742	940,103	936,464	932,825	929,186	925,547	921,908	918,269	914,630	910,991	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		8,189	8,158	8,127	8,095	8,064	8,033	8,001	7,968	7,948	7,917	7,886	7,854	$96,322
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.65%		2,251	2,252	2,244	2,235	2,226	2,218	2,209	2,200	2,192	2,183	2,175	2,166	26,551
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.21%		3,638	3,638	3,638	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	43,668
	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	0.007850		679	679	679	679	679	679	679	679	679	679	679	679	8,148
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,778	14,738	14,689	14,656	14,618	14,579	14,538	14,494	14,458	14,418	14,379	14,338	174,690
	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			14,778	14,738	14,689	14,656	14,618	14,579	14,538	14,494	14,458	14,418	14,379	14,338	174,690

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	
3	Less: Accumulated Depreciation		(37,782)	(46,703)	(55,624)	(64,545)	(73,466)	(82,387)	(91,308)	(100,229)	(109,150)	(118,071)	(126,992)	(135,913)	(144,834)	
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)		$2,335,991	2,327,070	2,318,149	2,309,228	2,300,307	2,291,386	2,282,465	2,273,544	2,264,623	2,255,702	2,246,781	2,237,860	2,228,939	
6	Average Net Investment			2,331,531	2,322,610	2,313,689	2,304,768	2,295,847	2,286,926	2,278,005	2,269,084	2,260,163	2,251,242	2,242,321	2,233,400	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		20,102	20,025	19,948	19,871	19,794	19,717	19,640	19,563	19,486	19,409	19,333	19,256	$236,144
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.65%		5,543	5,522	5,501	5,480	5,458	5,437	5,416	5,395	5,374	5,352	5,331	5,310	65,119
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.61%		8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	107,052
	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	0.009270		1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	22,008
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			36,400	36,302	36,204	36,106	36,007	35,909	35,811	35,713	35,615	35,516	35,419	35,321	430,323
	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			36,400	36,302	36,204	36,106	36,007	35,909	35,811	35,713	35,615	35,516	35,419	35,321	430,323

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.5 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(37,326)	(37,642)	(37,958)	(38,274)	(38,590)	(38,906)	(39,222)	(39,538)	(39,854)	(40,170)	(40,486)	(40,802)	(41,118)	
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)		$104,108	103,792	103,476	103,160	102,844	102,528	102,212	101,896	101,580	101,264	100,948	100,632	100,316	
6	Average Net Investment			103,950	103,634	103,318	103,002	102,686	102,370	102,054	101,738	101,422	101,106	100,790	100,474	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		896	893	891	888	885	883	880	877	874	872	869	866	$10,574
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.57%		247	246	246	245	244	243	243	242	241	240	240	239	2,916
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.66%		316	316	316	316	316	316	316	316	316	316	316	316	3,792
	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	0.613790		163	163	163	163	163	163	163	163	163	163	163	163	1,956
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,622	1,618	1,616	1,612	1,608	1,605	1,602	1,598	1,594	1,591	1,588	1,584	19,238
	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			1,622	1,618	1,616	1,612	1,608	1,605	1,602	1,598	1,594	1,591	1,588	1,584	19,238

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(22,216)	(23,253)	(24,288)	(25,323)	(26,358)	(27,393)	(28,428)	(29,463)	(30,498)	(31,533)	(32,568)	(33,603)	(34,638)	
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)		$268,080	267,045	266,010	264,975	263,940	262,905	261,870	260,835	259,800	258,765	257,730	256,695	255,660	
6	Average Net Investment			267,562	266,527	265,492	264,457	263,422	262,387	261,352	260,317	259,282	258,247	257,212	256,177	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		2,307	2,298	2,289	2,280	2,271	2,262	2,253	2,244	2,235	2,227	2,218	2,209	$27,093
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.57%		638	634	631	628	626	624	621	619	616	614	612	608	7,471
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.29%		1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	12,420
	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	0.607190		172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,048	4,037	4,025	48,048
	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			4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,048	4,037	4,025	48,048

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-4)
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CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Crystal River 4 & 5 (Project 4.2a)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	2,035,690	
3	Less: Accumulated Depreciation		(59,422)	(63,833)	(68,244)	(72,655)	(77,066)	(81,477)	(85,888)	(90,299)	(94,710)	(99,121)	(103,532)	(107,943)	(112,354)	
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)		$1,976,276	1,971,866	1,967,454	1,963,043	1,958,632	1,954,221	1,949,810	1,945,399	1,940,988	1,936,577	1,932,166	1,927,755	1,923,344	
6	Average Net Investment			1,974,071	1,969,660	1,965,248	1,960,838	1,956,427	1,952,016	1,947,605	1,943,194	1,938,783	1,934,372	1,929,961	1,926,550	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		17,070	16,982	16,944	16,906	16,868	16,830	16,792	16,754	16,716	16,678	16,639	16,601	$201,730
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		4,683	4,683	4,672	4,662	4,651	4,641	4,630	4,620	4,609	4,599	4,588	4,578	55,636
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	52,932
	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	0.818480		1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	21,336
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			27,992	27,854	27,805	27,757	27,708	27,660	27,611	27,563	27,514	27,466	27,416	27,368	331,624
	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			27,992	27,854	27,805	27,757	27,708	27,660	27,611	27,563	27,514	27,466	27,416	27,368	331,624

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1I)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	
3	Less: Accumulated Depreciation		(10,374)	(10,896)	(11,538)	(12,120)	(12,702)	(13,284)	(13,866)	(14,448)	(15,030)	(15,612)	(16,194)	(16,776)	(17,358)	
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)		$333,519	332,997	332,355	331,773	331,191	330,609	330,027	329,445	328,863	328,281	327,699	327,117	326,535	
6	Average Net Investment			333,228	332,646	332,064	331,482	330,900	330,318	329,736	329,154	328,572	327,990	327,408	326,826	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		2,879	2,855	2,853	2,858	2,853	2,848	2,843	2,838	2,833	2,828	2,823	2,818	$34,145
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		792	791	789	788	787	785	784	783	781	780	778	777	9,415
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.03%		582	582	582	582	582	582	582	582	582	582	582	582	6,984
	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	0.908130		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)			4,569	4,503	4,496	4,490	4,484	4,477	4,471	4,465	4,458	4,452	4,445	4,439	53,669
	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			4,569	4,503	4,496	4,490	4,484	4,477	4,471	4,465	4,458	4,452	4,445	4,439	53,669

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(4,583)	(5,150)	(5,747)	(6,344)	(6,941)	(7,538)	(8,135)	(8,732)	(9,329)	(9,926)	(10,523)	(11,120)	(11,717)	
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)		$157,171	156,604	156,007	155,410	154,813	154,216	153,619	153,022	152,425	151,828	151,231	150,634	150,037	
6	Average Net Investment			156,903	156,306	155,709	155,112	154,515	153,918	153,321	152,724	152,127	151,530	150,933	150,336	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		1,353	1,348	1,342	1,337	1,332	1,327	1,322	1,317	1,312	1,309	1,301	1,296	$15,893
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		373	372	370	369	367	366	365	363	362	360	359	357	4,383
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.43%		597	597	597	597	597	597	597	597	597	597	597	597	7,164
	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	0.008760		118	118	118	118	118	118	118	118	118	118	118	118	1,418
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,441	2,435	2,427	2,421	2,414	2,408	2,402	2,395	2,389	2,381	2,375	2,368	28,856
	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			2,441	2,435	2,427	2,421	2,414	2,408	2,402	2,395	2,389	2,381	2,375	2,368	28,856

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$276,347	276,347	276,347	276,347	276,347	276,347	276,347	276,347	276,347	276,347	276,347	276,347	276,347	
3	Less: Accumulated Depreciation		(19,273)	(19,798)	(20,323)	(20,848)	(21,373)	(21,898)	(22,423)	(22,948)	(23,473)	(23,998)	(24,523)	(25,048)	(25,573)	
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)		$256,074	256,549	256,024	255,499	254,974	254,449	253,924	253,399	252,874	252,349	251,824	251,299	250,774	
6	Average Net Investment			256,312	256,287	255,762	255,237	254,712	254,187	253,662	253,137	252,612	252,087	251,562	251,037	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		2,209	2,207	2,205	2,202	2,197	2,193	2,188	2,184	2,179	2,175	2,170	2,166	$26,167
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		608	607	606	604	603	602	601	599	598	597	595	594	7,215
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.29%		525	525	525	525	525	525	525	525	525	525	525	525	6,300
	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	0.008136		209	209	209	209	209	209	209	209	209	209	209	209	2,508
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,548	3,542	3,536	3,530	3,524	3,519	3,513	3,507	3,501	3,496	3,490	3,484	42,190
	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			3,548	3,542	3,536	3,530	3,524	3,519	3,513	3,507	3,501	3,496	3,490	3,484	42,190

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(11,979)	(11,772)	(12,465)	(13,158)	(13,851)	(14,544)	(15,237)	(15,930)	(16,623)	(17,316)	(18,009)	(18,702)	(19,395)	
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)		$187,009	187,216	186,523	185,830	185,137	184,444	183,751	183,058	182,365	181,672	180,979	180,286	179,593	
6	Average Net Investment			187,563	186,870	186,177	185,484	184,791	184,098	183,405	182,712	182,019	181,326	180,633	179,940	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.36%		1,617	1,611	1,605	1,599	1,593	1,587	1,581	1,575	1,569	1,563	1,557	1,551	$19,009
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		448	444	443	441	439	438	436	434	433	431	429	428	5,242
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.19%		693	693	693	693	693	693	693	693	693	693	693	693	8,316
	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	0.009136		151	151	151	151	151	151	151	151	151	151	151	151	1,812
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,907	2,899	2,892	2,884	2,876	2,869	2,861	2,853	2,846	2,838	2,830	2,823	34,376
	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			2,907	2,899	2,892	2,884	2,876	2,869	2,861	2,853	2,846	2,838	2,830	2,823	34,376

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$87,867	87,867	87,867	87,867	87,867	87,867	87,867	87,867	87,867	87,867	87,867	87,867	87,867	
3	Less: Accumulated Depreciation		(6,378)	(6,657)	(6,936)	(7,221)	(7,503)	(7,785)	(8,067)	(8,349)	(8,631)	(8,913)	(9,195)	(9,477)	(9,759)	
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)		$81,292	81,210	80,728	80,446	80,164	79,882	79,800	79,518	79,236	78,954	78,672	78,390	77,908	
6	Average Net Investment			81,151	80,869	80,587	80,305	80,023	79,741	79,459	79,177	78,895	78,613	78,331	78,049	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.36%		700	697	695	692	690	688	685	683	680	678	675	673	$8,236
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		193	192	192	191	190	190	189	188	188	187	186	186	2,272
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.86%		282	282	282	282	282	282	282	282	282	282	282	282	3,384
	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	0.009270		68	68	68	68	68	68	68	68	68	68	68	68	816
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,243	1,239	1,237	1,233	1,230	1,228	1,224	1,221	1,218	1,215	1,211	1,209	14,708
	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			1,243	1,239	1,237	1,233	1,230	1,228	1,224	1,221	1,218	1,215	1,211	1,209	14,708

Docket No. 090007-EI
Progress Energy Florida
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	
3	Less: Accumulated Depreciation		(6,997)	(6,539)	(6,381)	(6,223)	(6,065)	(5,907)	(5,749)	(5,591)	(5,433)	(5,275)	(5,117)	(4,959)	(4,801)	
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)		$338,793	338,951	339,109	339,267	339,425	339,583	339,741	339,899	340,057	340,215	340,373	340,531	340,689	
6	Average Net Investment			338,872	339,030	339,188	339,346	339,504	339,662	339,820	339,978	340,136	340,294	340,452	340,610	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		2,922	2,923	2,924	2,926	2,927	2,928	2,930	2,931	2,933	2,934	2,935	2,937	$35,150
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		808	808	808	807	807	808	808	808	809	809	809	810	9,693
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	-0.55%		(158)	(158)	(158)	(158)	(158)	(158)	(158)	(158)	(158)	(158)	(158)	(158)	(1,896)
	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	0.009130		263	263	263	263	263	263	263	263	263	263	263	263	3,156
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,833	3,834	3,835	3,838	3,839	3,841	3,843	3,844	3,847	3,848	3,849	3,852	46,103
	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			3,833	3,834	3,835	3,838	3,839	3,841	3,843	3,844	3,847	3,848	3,849	3,852	46,103

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(19,459)	(22,305)	(25,151)	(27,997)	(30,843)	(33,689)	(36,535)	(39,381)	(42,227)	(45,073)	(47,919)	(50,765)	(53,611)	
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)		$330,126	327,279	324,433	321,587	318,741	315,895	313,049	310,203	307,357	304,511	301,665	298,819	295,973	
6	Average Net Investment			328,702	325,856	323,010	320,164	317,318	314,472	311,626	308,780	305,934	303,088	300,242	297,396	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		2,834	2,809	2,785	2,760	2,736	2,711	2,687	2,662	2,638	2,613	2,589	2,564	$32,388
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		781	775	768	761	754	748	741	734	727	721	714	707	8,931
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	9.77%		2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	34,152
	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	0.007740		225	225	225	225	225	225	225	225	225	225	225	225	2,700
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			6,686	6,655	6,624	6,592	6,561	6,530	6,499	6,467	6,436	6,405	6,374	6,342	78,171
	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			6,686	6,655	6,624	6,592	6,561	6,530	6,499	6,467	6,436	6,405	6,374	6,342	78,171

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Progress Energy Florida
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - TURNER (Project 7.2g)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(7,767)	(7,854)	(7,941)	(8,028)	(8,115)	(8,202)	(8,289)	(8,376)	(8,463)	(8,550)	(8,637)	(8,724)	(8,811)	
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)		$126,245	126,158	126,071	125,984	125,897	125,810	125,723	125,636	125,549	125,462	125,375	125,288	125,201	
6	Average Net Investment			126,201	126,114	126,027	125,940	125,853	125,766	125,679	125,592	125,505	125,418	125,331	125,244	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.36%		1,089	1,087	1,087	1,086	1,085	1,084	1,084	1,083	1,082	1,081	1,081	1,080	$13,008
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.65%		300	300	300	299	299	299	299	299	298	298	298	298	3,587
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	0.74%		87	87	87	87	87	87	87	87	87	87	87	87	1,044
	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	0.009270		104	104	104	104	104	104	104	104	104	104	104	104	1,248
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,579	1,578	1,578	1,576	1,575	1,574	1,574	1,573	1,571	1,570	1,570	1,569	18,887
	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			1,579	1,578	1,578	1,576	1,575	1,574	1,574	1,573	1,571	1,570	1,570	1,569	18,887

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$381,580	381,580	381,580	381,580	381,580	381,580	381,580	381,580	381,580	381,580	381,580	381,580	381,580	
3	Less: Accumulated Depreciation		(16,822)	(16,925)	(17,228)	(17,931)	(18,634)	(19,337)	(20,040)	(20,743)	(21,446)	(22,149)	(22,852)	(23,555)	(24,258)	
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)		$364,758	364,655	364,352	363,649	362,946	362,243	361,540	360,837	360,134	359,431	358,728	358,025	357,322	
6	Average Net Investment			364,706	364,503	364,000	363,297	362,594	361,891	361,188	360,485	359,782	359,079	358,376	357,673	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.36%		3,150	3,144	3,138	3,132	3,126	3,120	3,114	3,108	3,102	3,096	3,090	3,084	$37,404
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.65%		869	867	865	864	862	860	859	857	855	854	852	850	10,314
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.21%		703	703	703	703	703	703	703	703	703	703	703	703	8,436
	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	0.007850		250	250	250	250	250	250	250	250	250	250	250	250	3,000
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,972	4,964	4,956	4,949	4,941	4,933	4,926	4,918	4,910	4,903	4,895	4,887	59,154
	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			4,972	4,964	4,956	4,949	4,941	4,933	4,926	4,918	4,910	4,903	4,895	4,887	59,154

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	
3	Less: Accumulated Depreciation		(863,408)	(893,224)	(923,043)	(952,862)	(982,681)	(1,012,500)	(1,042,319)	(1,072,138)	(1,101,957)	(1,131,776)	(1,161,595)	(1,191,414)	(1,221,233)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$14,626,977	14,597,158	14,567,339	14,537,520	14,507,701	14,477,882	14,448,063	14,418,244	14,388,425	14,358,606	14,328,787	14,298,968	14,269,149	
6	Average Net Investment			14,612,068	14,582,249	14,552,430	14,522,611	14,492,792	14,462,973	14,433,154	14,403,335	14,373,516	14,343,697	14,313,878	14,284,059	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		126,000	125,723	125,466	125,209	124,952	124,695	124,438	124,181	123,924	123,667	123,409	123,152	$1,494,796
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		34,740	34,668	34,598	34,528	34,457	34,388	34,315	34,244	34,173	34,102	34,031	33,960	412,203
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.31%		29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	357,828
	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	0.010480		13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	162,336
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			204,087	203,739	203,411	203,084	202,756	202,428	202,100	201,772	201,444	201,116	200,787	200,459	2,427,163
	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			204,087	203,739	203,411	203,084	202,756	202,428	202,100	201,772	201,444	201,116	200,787	200,459	2,427,163

For Project: CAIR/CAMR Crystal River AFUDC - Low Nox Burner CR4 (Project 7.4b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	
3	Less: Accumulated Depreciation		(271,659)	(316,560)	(361,461)	(406,362)	(451,263)	(496,164)	(541,065)	(585,966)	(630,867)	(675,768)	(720,669)	(765,570)	(810,471)	
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)		$10,150,322	10,105,421	10,060,520	10,015,619	9,970,718	9,925,817	9,880,916	9,836,015	9,791,114	9,746,213	9,701,312	9,656,411	9,611,510	
6	Average Net Investment			10,127,871	10,082,970	10,038,069	9,993,168	9,948,268	9,903,367	9,858,466	9,813,565	9,768,664	9,723,763	9,678,862	9,633,961	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		87,319	86,932	86,545	86,158	85,771	85,384	84,996	84,609	84,222	83,835	83,448	83,061	$1,022,260
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		24,079	23,972	23,866	23,759	23,652	23,545	23,439	23,332	23,225	23,118	23,011	22,905	281,903
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	538,812
	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	0.010480		9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	109,224
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			165,401	164,907	164,414	163,920	163,426	162,932	162,438	161,944	161,450	160,956	160,462	159,969	1,952,219
	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			165,401	164,907	164,414	163,920	163,426	162,932	162,438	161,944	161,450	160,956	160,462	159,969	1,952,219

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments														
	a. Expenditures/Additions		20,000	20,000	20,000	20,000	20,000	20,000	20,000	$0	$0	$0	$0	$0	$140,000
	b. Clearings to Plant		20,000	20,000	20,000	20,000	20,000	20,000	20,000	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	$92,494,737	92,514,737	92,534,737	92,554,737	92,574,737	92,594,737	92,614,737	92,634,737	92,634,737	92,634,737	92,634,737	92,634,737	92,634,737	
3	Less: Accumulated Depreciation	(1,414,831)	(1,813,115)	(2,211,785)	(2,610,542)	(3,009,385)	(3,408,314)	(3,807,329)	(4,206,430)	(4,605,531)	(5,004,632)	(5,403,733)	(5,802,834)	(6,201,935)	
4	CWIP - Non-Interest Bearing	-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$91,079,906	90,701,622	90,322,952	89,944,195	89,565,352	89,186,423	88,807,408	88,428,307	88,029,206	87,630,105	87,231,004	86,831,903	86,432,802	
6	Average Net Investment		90,890,914	90,512,287	90,133,573	89,754,773	89,375,887	88,996,915	88,617,857	88,228,756	87,829,655	87,430,554	87,031,453	86,632,352	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	10.25%	783,031	780,387	777,102	773,835	770,569	767,302	764,034	760,679	757,239	753,797	750,356	746,915	$9,185,626
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%	216,093	215,193	214,293	213,392	212,491	211,590	210,689	209,764	208,815	207,866	206,917	205,968	2,533,071
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	5.17%	398,584	398,670	398,757	398,843	398,929	399,015	399,101	399,101	399,101	399,101	399,101	399,101	4,787,404
	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	0.016480	80,796	80,814	80,831	80,849	80,866	80,884	80,901	80,901	80,901	80,901	80,901	80,901	970,448
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,479,104	1,475,044	1,470,983	1,466,920	1,462,855	1,458,791	1,454,725	1,450,445	1,446,055	1,441,665	1,437,275	1,432,885	17,476,747
	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		1,479,104	1,475,044	1,470,983	1,466,920	1,462,855	1,458,791	1,454,725	1,450,445	1,446,055	1,441,665	1,437,275	1,432,885	17,476,747

For Project: CAIR/CAMR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments														
	a. Expenditures/Additions		1,540,000	2,041,796	2,589,985	1,100,000	1,545,160	1,500,000	500,000	254,844	$0	$0	$0	$0	$11,971,785
	b. Clearings to Plant		1,540,000	2,041,796	2,589,985	1,100,000	1,545,160	1,500,000	500,000	254,844	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	$634,421,721	635,961,721	638,003,517	640,593,502	641,693,502	643,238,662	644,738,662	645,238,662	645,493,506	645,493,506	645,493,506	645,493,506	645,493,506	
3	Less: Accumulated Depreciation	(748,089)	(3,488,924)	(6,238,756)	(8,998,648)	(11,761,276)	(14,532,563)	(17,310,312)	(20,090,218)	(22,871,216)	(25,652,217)	(28,433,218)	(31,214,219)	(33,995,220)	
4	CWIP - Non-Interest Bearing	-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$633,673,632	632,473,897	631,766,761	631,594,856	629,932,226	628,706,099	627,428,350	625,148,447	622,622,290	619,841,289	617,060,288	614,279,287	611,498,286	
6	Average Net Investment		633,073,865	632,120,229	631,681,809	630,764,541	629,319,163	628,067,225	626,288,399	623,885,369	621,231,790	618,450,788	615,669,786	612,888,787	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	10.25%	5,456,150	5,449,930	5,446,150	5,438,242	5,425,780	5,414,966	5,399,650	5,378,932	5,356,053	5,332,077	5,308,100	5,284,123	$64,692,173
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%	1,505,133	1,502,858	1,501,824	1,499,643	1,496,206	1,493,230	1,488,991	1,483,287	1,476,979	1,470,367	1,463,755	1,457,143	17,839,434
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation	5.17%	2,739,835	2,748,732	2,759,890	2,764,636	2,771,287	2,777,749	2,779,903	2,781,001	2,781,001	2,781,001	2,781,001	2,781,001	33,247,131
	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	0.016480	555,407	557,190	559,452	560,412	561,762	563,072	563,508	563,731	563,731	563,731	563,731	563,731	6,739,458
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,256,525	10,258,710	10,267,316	10,262,927	10,255,035	10,249,037	10,232,052	10,206,951	10,177,764	10,147,176	10,116,587	10,085,998	122,518,196
	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		10,256,525	10,258,710	10,267,316	10,262,927	10,255,035	10,249,037	10,232,052	10,206,951	10,177,764	10,147,176	10,116,587	10,085,998	122,518,196

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - SCR Common Items (Project 7.4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473.14	69,831,473	
3	Less: Accumulated Depreciation		(906,773)	(1,206,630)	(1,507,487)	(1,808,344)	(2,109,201)	(2,410,058)	(2,710,915)	(3,011,772)	(3,312,629)	(3,613,486)	(3,914,343)	(4,215,200)	(4,516,057)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$68,924,700	68,624,843	68,323,986	68,023,129	67,722,272	67,421,415	67,120,558	66,819,701	66,518,844	66,217,987	65,917,130	65,616,273	65,315,416	
6	Average Net Investment			68,775,272	68,474,415	68,173,558	67,872,701	67,571,844	67,270,987	66,970,130	66,669,273	66,368,416	66,067,559	65,766,702	65,465,845	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		592,957	590,364	587,770	585,176	582,582	579,988	577,394	574,800	572,206	569,612	567,019	564,425	$6,944,293
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		163,513	162,798	162,083	161,367	160,652	159,937	159,221	158,506	157,791	157,076	156,360	155,645	1,914,949
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	3,610,284
	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	0.010460		60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	731,832
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,118,313	1,115,005	1,111,696	1,108,386	1,105,077	1,101,768	1,098,458	1,095,149	1,091,840	1,088,531	1,085,222	1,081,913	13,201,358
	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			1,118,313	1,115,005	1,111,696	1,108,386	1,105,077	1,101,768	1,098,458	1,095,149	1,091,840	1,088,531	1,085,222	1,081,913	13,201,358

For Project: CAIR/CAMR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	1,228,484	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,228,484
	b. Clearings to Plant			0	1,228,484	0	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		$135,013,655	135,013,655	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	
3	Less: Accumulated Depreciation		(169,204)	(740,888)	(1,327,856)	(1,914,824)	(2,501,792)	(3,088,760)	(3,675,728)	(4,262,696)	(4,849,664)	(5,436,632)	(6,023,600)	(6,610,568)	(7,197,536)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$134,844,452	134,272,768	134,912,204	134,325,236	133,738,268	133,151,300	132,564,332	131,977,364	131,390,396	130,803,428	130,216,460	129,629,492	129,042,524	
6	Average Net Investment			134,583,610	134,592,486	134,818,720	134,031,752	133,444,784	132,857,816	132,270,848	131,683,880	131,096,912	130,509,944	129,922,976	129,336,008	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		1,160,153	1,160,412	1,160,638	1,155,577	1,150,516	1,145,456	1,140,395	1,135,335	1,130,274	1,125,213	1,120,153	1,115,092	$13,699,224
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		319,925	319,994	320,056	318,660	317,265	315,869	314,474	313,078	311,683	310,287	308,892	307,496	3,777,879
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		581,684	586,968	586,968	586,968	586,968	586,968	586,968	586,968	586,968	586,968	586,968	586,968	7,038,332
	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	0.010460		117,912	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	1,426,725
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,179,684	2,186,357	2,186,645	2,180,188	2,173,732	2,167,276	2,160,820	2,154,364	2,147,908	2,141,451	2,134,996	2,128,539	25,941,960
	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			2,179,684	2,186,357	2,186,645	2,180,188	2,173,732	2,167,276	2,160,820	2,154,364	2,147,908	2,141,451	2,134,996	2,128,539	25,941,960

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010
For Project: CAIR/CAMR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing controls (Project 7.4g)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$928,220	928,220	928,220	928,220	928,220	928,220	928,220	928,220	928,220	928,220	928,220	928,220	928,220	
3	Less: Accumulated Depreciation		(1,098)	(3,099)	(5,102)	(13,105)	(17,108)	(21,111)	(25,114)	(29,117)	(33,120)	(37,123)	(41,126)	(45,129)	(49,132)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$928,126	924,122	920,119	916,116	912,113	906,110	904,107	900,104	896,101	892,098	888,095	884,092	880,089	
6	Average Net Investment			926,123	922,120	918,117	914,114	910,111	905,108	902,105	898,102	894,099	890,096	886,093	882,090	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		7,985	7,950	7,916	7,881	7,847	7,812	7,778	7,743	7,709	7,674	7,640	7,605	$93,540
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		2,202	2,192	2,183	2,173	2,164	2,154	2,145	2,135	2,126	2,116	2,107	2,097	25,794
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	48,036
	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	0.010460		812	812	812	812	812	812	812	812	812	812	812	812	9,744
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			15,002	14,957	14,914	14,869	14,826	14,781	14,738	14,693	14,650	14,605	14,562	14,517	177,114
	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			15,002	14,957	14,914	14,869	14,826	14,781	14,738	14,693	14,650	14,605	14,562	14,517	177,114

For Project: CAIR/CAMR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing controls (Project 7.4h)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$ 949,211	$0	$0	$0	$0	$0	$0	$0	$949,211
	b. Clearings to Plant			0	0	0	0	949,211	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	949,211	949,211	949,211	949,211	949,211	949,211	949,211	949,211	
3	Less: Accumulated Depreciation		-	0	0	0	0	(2,045)	(6,135)	(10,225)	(14,315)	(18,405)	(22,495)	(26,585)	(30,675)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	947,166	943,076	938,986	934,896	930,806	926,716	922,626	918,536	
6	Average Net Investment			0	0	0	0	473,583	945,121	941,031	936,941	932,851	928,761	924,671	920,581	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		0	0	0	0	4,083	8,149	8,113	8,078	8,043	8,007	7,972	7,937	$60,382
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		0	0	0	0	1,126	2,247	2,237	2,228	2,218	2,208	2,198	2,189	16,651
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		0	0	0	0	2,045	4,090	4,090	4,090	4,090	4,090	4,090	4,090	30,675
	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	0.010460		0	0	0	0	829	829	829	829	829	829	829	829	8,632
	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	8,083	15,315	15,269	15,225	15,180	15,134	15,089	15,045	114,340
	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	8,083	15,315	15,269	15,225	15,180	15,134	15,089	15,045	114,340

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

CPD

For Project: CAIR/CAMR Crystal River AFUDC - CR4 SCR (Project 7.4i)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$108,219,363	1,435,813	1,832,028	195,809	183,116	174,307	174,129	174,076	$112,188,441
	b. Clearings to Plant			0	0	0	0	108,219,363	1,435,813	1,832,028	195,809	183,116	174,307	174,129	174,076	
	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	108,219,363	109,654,976	111,287,004	111,482,813	111,666,929	111,840,235	112,014,364	112,188,441	
3	Less: Accumulated Depreciation		-	0	0	0	0	(233,123)	(705,553)	(1,185,015)	(1,665,320)	(2,146,414)	(2,626,259)	(3,110,854)	(3,594,199)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	107,986,241	108,949,423	110,101,990	109,817,494	109,519,515	109,211,977	108,903,511	108,594,242	
6	Average Net Investment			0	0	0	0	53,993,120	108,467,832	109,525,707	109,959,742	109,668,504	109,365,746	109,057,744	108,748,877	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		0	0	0	0	465,511	935,173	944,294	948,039	945,525	942,915	940,260	937,597	$7,059,311
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		0	0	0	0	128,369	257,882	260,397	261,429	260,737	260,017	259,255	258,550	1,946,666
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		0	0	0	0	233,123	472,430	479,462	480,305	481,094	481,845	482,595	483,345	3,594,199
	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	0.010480		0	0	0	0	94,512	95,765	97,191	97,362	97,522	97,674	97,826	97,978	775,830
	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	921,515	1,761,250	1,781,344	1,787,132	1,784,878	1,782,451	1,779,936	1,777,470	13,376,006
	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			0	0	0	0	921,515	1,761,250	1,781,344	1,787,132	1,784,878	1,782,451	1,779,936	1,777,470	13,376,006

For Project: CAIR/CAMR Crystal River AFUDC - CR4 FGD (Project 7.4i)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$138,386,946	478,327	1,779,294	239,128	223,627	212,870	212,652	212,586	$141,745,432
	b. Clearings to Plant			0	0	0	0	138,386,946	478,327	1,779,294	239,128	223,627	212,870	212,652	212,586	
	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	138,386,946	138,865,273	140,644,566	140,883,695	141,107,322	141,320,191	141,532,844	141,745,432	
3	Less: Accumulated Depreciation		-	0	0	0	0	(295,109)	(999,367)	(1,502,331)	(2,109,305)	(2,717,242)	(3,326,096)	(3,935,867)	(4,546,554)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	138,086,838	137,865,886	139,142,236	138,774,390	138,390,080	137,994,096	137,596,977	137,198,878	
6	Average Net Investment			0	0	0	0	69,044,419	138,028,862	138,555,561	138,958,313	138,582,235	138,192,088	137,795,537	137,397,928	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		0	0	0	0	595,278	1,190,039	1,194,580	1,198,052	1,194,810	1,191,446	1,188,027	1,184,599	$8,936,831
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		0	0	0	0	164,153	328,164	329,416	330,375	329,479	328,552	327,609	326,664	2,464,410
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		0	0	0	0	298,109	596,278	605,944	606,974	607,937	608,854	609,771	610,687	4,546,554
	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	0.010480		0	0	0	0	120,858	121,278	122,830	123,035	123,234	123,430	123,605	123,791	982,052
	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	1,178,398	2,237,757	2,252,770	2,258,437	2,255,460	2,252,272	2,249,012	2,245,741	16,929,847
	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	1,178,398	2,237,757	2,252,770	2,258,437	2,255,460	2,252,272	2,249,012	2,245,741	16,929,847

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	
3	Less: Accumulated Depreciation		(44,964)	(134,892)	(224,820)	(314,748)	(404,676)	(494,604)	(584,532)	(674,460)	(764,388)	(854,316)	(944,244)	(1,034,172)	(1,124,100)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$20,828,054	20,738,126	20,648,198	20,558,270	20,468,342	20,378,414	20,288,486	20,198,558	20,108,630	20,018,702	19,928,774	19,838,846	19,748,918	
6	Average Net Investment			20,783,090	20,693,162	20,603,234	20,513,306	20,423,378	20,333,450	20,243,522	20,153,594	20,063,666	19,973,738	19,883,810	19,793,882	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		179,195	178,416	177,634	176,859	176,084	175,308	174,533	173,758	172,982	172,207	171,432	170,656	$2,089,645
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		49,412	49,198	48,984	48,770	48,557	48,343	48,129	47,915	47,701	47,486	47,274	47,060	576,831
	c. Other			114,545	0	0	0	0	0	0	0	0	0	0	0	114,545
8	Investment Expenses															
	a. Depreciation	5.17%		89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	1,079,136
	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	0.010480		18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	218,748
	e. Other			83,193	0	0	0	0	0	0	0	0	0	0	0	83,193
9	Total System Recoverable Expenses (Lines 7 + 8)			514,492	335,765	334,775	333,768	332,798	331,808	330,819	329,830	328,840	327,852	326,863	325,873	4,153,501
	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			514,492	335,765	334,775	333,768	332,798	331,808	330,819	329,830	328,840	327,852	326,863	325,873	4,153,501

Progress Energy Florida
Witness: T.G. Foster
Exhibit No.___(TGF-4)
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DOCKET NO. 090007-EI
FINAL ECRC 2008 TRUE-UP
EXHIBIT HTB-1

INDEX

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2008 THROUGH DECEMBER 2008

FORMS 42-1A THROUGH 42-8A

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 28
COMPANY Tampa Electric Company (Direct)
WITNESS Howard T. Bryant (HTB-1)
DATE 11/02/09

Tampa Electric Company

Form 42 - 1A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008
(in Dollars)

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2008 to December 2008 (Form 42-2A, Lines 5 + 6 + 10)	($15,866,217)
2.	Estimated/Actual True-Up Amount Approved for the Period January 2008 to December 2008 (Order No. PSC-08-0775 FOF-EI)	(7,753,224)
3.	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2010 to December 2010 (Lines 1 - 2)	($8,112,993)

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DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
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Form 42 - 2A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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)	$1,638,579	$1,370,190	$1,402,163	$1,497,358	$1,604,847	$1,896,228	$1,838,115	$1,859,793	$1,976,888	$1,751,627	$1,464,969	$1,484,593	$19,785,350
2.	True-Up Provision	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,287)	(2,271,510)
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	1,449,286	1,180,897	1,212,870	1,308,065	1,415,554	1,706,935	1,648,822	1,670,500	1,787,595	1,562,334	1,275,676	1,295,306	17,513,840
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	934,271	952,608	(142,256)	828,339	63,219	997,223	(77,784)	1,171,490	(1,883,087)	1,590,404	(3,475,832)	1,714,251	2,672,846
	b. Capital Investment Projects (Form 42-7A, Line 9)	2,134,304	2,110,308	2,120,016	2,105,726	2,116,026	2,149,067	2,919,008	3,010,781	3,014,505	3,029,460	3,035,487	3,067,296	30,811,984
	c. Total Jurisdictional ECRC Costs	3,068,575	3,062,916	1,977,760	2,934,065	2,179,245	3,146,290	2,841,224	4,182,271	1,131,418	4,619,864	(440,345)	4,781,547	33,484,830
5.	Over/Under Recovery (Line 3 - Line 4c)	(1,619,289)	(1,882,019)	(764,890)	(1,626,000)	(763,691)	(1,439,355)	(1,192,402)	(2,511,771)	656,177	(3,057,530)	1,716,021	(3,486,241)	(15,970,990)
6.	Interest Provision (Form 42-3A, Line 10)	31,846	20,427	16,266	13,326	10,676	8,020	5,778	2,398	1,353	(1,878)	(1,950)	(1,489)	104,773
7.	Beginning Balance True-Up & Interest Provision	(2,271,510)	(3,669,660)	(5,341,959)	(5,901,290)	(7,324,671)	(7,888,393)	(9,130,435)	(10,127,766)	(12,447,846)	(11,601,023)	(14,471,138)	(12,567,774)	(2,271,510)
	a. Deferred True-Up from January to December 2007 (Order No. PSC-08-0775-FOF-EI)	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395
8.	True-Up Collected/(Refunded) (see Line 2)	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,287	2,271,510
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	8,794,735	7,122,436	6,563,105	5,139,724	4,576,002	3,333,960	2,336,629	16,549	863,372	(2,006,743)	(103,379)	(3,401,822)	(3,401,822)
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)	$8,794,735	$7,122,436	$6,563,105	$5,139,724	$4,576,002	$3,333,960	$2,336,629	$16,549	$863,372	($2,006,743)	($103,379)	($3,401,822)	($3,401,822)

Form 42 - 1P
REVISED 10/19/09

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2010 to December 2010

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)	$18,046,706	$168,214	$18,214,920
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	57,071,583	149,366	57,220,949
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	75,118,289	317,580	75,435,869
2. True-up for Estimated Over/(Under) Recovery for the current period January 2009 to December 2009* (Form 42-2E, Line 5 + 6 + 10)	(9,193,784)	(85,345)	(9,279,129)
3. Final True-up for the period January 2008 to December 2008 (Form 42-1A, Line 3)	(7,994,185)	(118,808)	(8,112,993)
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2010 to December 2010 (Line 1 - Line 2- Line 3)	92,306,258	521,733	92,827,991
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$92,372,719	$522,109	$92,894,828

* 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. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 1

Form 42 - 4A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual	(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	$ 3,342,509	$ 3,287,684	$ 54,825	1.7%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(11,656,193)	(18,765,601)	7,109,408	37.9%
	d. Big Bend Units 1 & 2 FGD	7,542,688	6,337,155	1,205,533	19.0%
	e. Big Bend PM Minimization and Monitoring	312,943	438,402	(125,459)	-28.6%
	f. Big Bend NO_x Emissions Reduction	475,890	512,435	(36,545)	-7.1%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	86,335	76,005	10,330	13.6%
	i. Polk NO_x Emissions Reduction	38,246	46,667	(8,421)	-18.0%
	j. Bayside SCR Consumables	146,098	108,068	38,030	35.2%
	k. Big Bend Unit 4 SOFA	24,282	32,976	(8,694)	-26.4%
	l. Big Bend Unit 1 Pre-SCR	0	30,000	(30,000)	-100.0%
	m. Big Bend Unit 2 Pre-SCR	6,951	11,188	(4,237)	-37.9%
	n. Big Bend Unit 3 Pre-SCR	2	2	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	149,902	124,395	25,507	20.5%
	p. Arsenic Groundwater Standard Program	72,656	98,651	(25,995)	-26.4%
	q. Big Bend 3 SCR	899,642	1,200,000	(300,358)	-25.0%
	r. Big Bend 4 SCR	1,301,024	1,331,036	(30,012)	-2.3%
2.	Total Investment Projects - Recoverable Costs	$2,777,475	($5,096,437)	$7,873,912	154.5%
3.	Recoverable Costs Allocated to Energy	$2,434,082	($5,429,988)	$7,864,070	144.8%
4.	Recoverable Costs Allocated to Demand	$343,393	$333,551	$9,842	3.0%

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-08-0775-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-3P
REVISED 10/19/09

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	$64,538	$64,385	$64,232	$64,079	$63,925	$63,771	$63,619	$63,465	$63,312	$63,158	$63,005	$62,852	$764,341		$764,341
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124		422,124
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510		78,510
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079	$ 53,079	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302	87,302	
	f.	Phillips Upgrade Tank # 1 for FDEP	480	478	477	476	474	473	472	470	469	468	466	464	5,667	5,667	
	g.	Phillips Upgrade Tank # 4 for FDEP	754	751	750	747	745	743	740	738	736	734	731	730	8,899	8,899	
	h.	Big Bend Unit 1 Classifier Replacement	11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795		133,795
	i.	Big Bend Unit 2 Classifier Replacement	8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974		96,974
	j.	Big Bend Section 114 Mercury Testing Platform	1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303		13,303
	k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	736,939	737,118	737,289	735,721	741,734	739,684	737,635	735,585	733,536	731,487	729,437	727,387	8,823,552		8,823,552
	l.	Big Bend FGD Optimization and Utilization	208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526		2,475,526
	m.	Big Bend NO_x Emissions Reduction	67,476	67,390	67,304	67,217	67,130	67,043	66,957	66,870	66,784	66,697	66,610	66,524	804,002		804,002
	n.	Big Bend PM Minimization and Monitoring	89,789	89,654	89,452	89,249	89,046	88,843	88,640	88,437	88,234	88,032	87,829	87,626	1,064,831		1,064,831
	o.	Polk NO_x Emissions Reduction	16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609		195,609
	p.	Big Bend Unit 4 SOFA	26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962		317,962
	q.	Big Bend Unit 1 Pre-SCR	22,533	22,489	22,444	22,400	22,356	22,312	22,268	22,224	22,180	22,136	22,092	22,048	267,482		267,482
	r.	Big Bend Unit 2 Pre-SCR	18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590		213,590
	s.	Big Bend Unit 3 Pre-SCR	30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931		366,931
	t.	Big Bend Unit 1 SCR	0	0	0	0	889,336	1,186,187	1,185,685	1,183,181	1,180,677	1,178,174	1,175,670	1,173,167	9,152,077		9,152,077
	u.	Big Bend Unit 2 SCR	1,102,544	1,100,274	1,098,003	1,095,733	1,093,462	1,091,192	1,088,921	1,086,651	1,084,381	1,082,110	1,079,840	1,077,568	13,080,679		13,080,679
	v.	Big Bend Unit 3 SCR	901,949	900,329	898,710	897,090	895,469	893,849	892,230	890,610	888,989	887,369	885,750	884,130	10,716,474		10,716,474
	w.	Big Bend Unit 4 SCR	676,425	677,237	676,049	674,861	673,673	672,485	671,297	670,109	668,920	667,732	666,544	665,356	8,062,688		8,062,688
	x.	Big Bend FGD System Reliability	129,171	128,955	128,739	128,523	128,306	129,303	131,514	134,939	140,791	145,914	148,369	150,094	1,624,618		1,624,618
	y.	Clean Air Mercury Rule	13,846	13,818	13,888	14,006	13,976	13,950	13,920	13,892	13,864	13,835	13,807	13,779	166,583		166,583
	z.	SO_2 Emissions Allowences (B)	(393)	(390)	(387)	(385)	(382)	(378)	(375)	(372)	(369)	(365)	(362)	(358)	(4,516)		(4,516)
		Total Investment Projects - Recoverable Costs	4,183,826	4,177,439	4,171,069	4,163,011	5,051,720	5,341,097	5,334,335	5,326,782	5,321,660	5,315,811	5,307,290	5,298,042	58,992,082	$ 154,947	$ 58,837,135
3.		Recoverable Costs Allocated to Energy	4,170,742	4,164,387	4,158,047	4,150,019	5,038,761	5,328,169	5,321,438	5,313,917	5,308,826	5,303,007	5,294,520	5,285,302	58,837,135		
4.		Recoverable Costs Allocated to Demand	13,084	13,052	13,022	12,992	12,959	12,928	12,897	12,865	12,834	12,804	12,770	12,740	154,947		
5.		Retail Energy Jurisdictional Factor	0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374			
6.		Retail Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735			
7.		Jurisdictional Energy Recoverable Costs (C)	4,078,518	4,051,001	4,052,893	4,028,512	4,851,813	5,172,135	5,153,576	5,125,551	5,133,985	5,120,588	5,139,602	5,163,409	57,071,583		
8.		Jurisdictional Demand Recoverable Costs (D)	12,613	12,582	12,553	12,524	12,492	12,462	12,432	12,402	12,372	12,343	12,310	12,281	149,366		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$4,091,131	$4,063,583	$4,065,446	$4,041,036	$4,864,305	$5,184,597	$5,166,008	$5,137,953	$5,146,357	$5,132,931	$5,151,912	$5,175,690	$57,220,949		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8P, Line 9
(B) Project's Total Return Component on Form 42-8P, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

DOCKET NO. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 3

Form 42 - 6A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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	$808,109	$808,109	$0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	459,431	459,431	0	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	82,704	82,704	0	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	56,068	56,068	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	92,212	92,212	0	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	6,064	6,064	0	0.0%
	g. Phillips Upgrade Tank # 4 for FDEP	9,528	9,528	0	0.0%
	h. Big Bend Unit 1 Classifier Replacement	143,853	143,853	0	0.0%
	i. Big Bend Unit 2 Classifier Replacement	104,046	104,046	0	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	13,858	13,858	0	0.0%
	k. Big Bend Units 1 & 2 FGD	8,916,407	8,920,859	(4,452)	0.0%
	l. Big Bend FGD Optimization and Utilization	2,590,639	2,590,639	0	0.0%
	m. Big Bend NO_x Emissions Reduction	797,443	798,805	(1,362)	-0.2%
	n. Big Bend PM Minimization and Monitoring	1,075,671	1,084,033	(8,362)	-0.8%
	o. Polk NO_x Emissions Reduction	207,879	207,879	0	0.0%
	p. Big Bend Unit 4 SOFA	332,096	332,096	0	0.0%
	q. Big Bend Unit 1 Pre-SCR	280,044	280,044	0	0.0%
	r. Big Bend Unit 2 Pre-SCR	224,909	224,909	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	361,148	356,032	5,116	1.4%
	t. Big Bend Unit 1 SCR	0	0	0	0.0%
	u. Big Bend Unit 2 SCR	0	0	0	0.0%
	v. Big Bend Unit 3 SCR	5,423,825	5,437,189	(13,364)	-0.2%
	w. Big Bend Unit 4 SCR	8,407,763	8,408,013	(250)	0.0%
	x. Big Bend FGD System Reliability	1,526,247	1,532,141	(5,894)	-0.4%
	y. Clean Air Mercury Rule	71,609	70,383	1,226	1.7%
	z. SO_2 Emissions Allowances	(6,513)	(5,743)	(770)	-13.4%
2.	Total Investment Projects - Recoverable Costs	$31,985,040	$32,013,152	($28,112)	-0.1%
3.	Recoverable Costs Allocated to Energy	$31,821,168	$31,849,280	($28,112)	-0.1%
4.	Recoverable Costs Allocated to Demand	$163,872	$163,872	$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-08-0775-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-7A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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	$68,185	$68,032	$67,879	$67,725	$67,572	$67,419	$67,266	$67,113	$66,959	$66,806	$66,653	$66,500	$808,109		$808,109
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	39,001	38,872	38,741	38,611	38,481	38,351	38,221	38,091	37,960	37,831	37,700	37,571	459,431		459,431
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,973	6,958	6,943	6,929	6,914	6,900	6,884	6,870	6,855	6,841	6,826	6,811	82,704		82,704
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,729	4,719	4,709	4,699	4,688	4,678	4,667	4,657	4,646	4,636	4,625	4,615	56,068	$ 56,068	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,780	7,762	7,744	7,727	7,710	7,693	7,676	7,658	7,641	7,624	7,607	7,590	92,212	92,212	
	f.	Phillips Upgrade Tank # 1 for FDEP	513	511	510	509	507	506	505	503	502	501	499	498	6,064	6,064	
	g.	Phillips Upgrade Tank # 4 for FDEP	806	804	801	800	797	795	793	791	788	787	784	782	9,528	9,528	
	h.	Big Bend Unit 1 Classifier Replacement	12,181	12,146	12,110	12,076	12,040	12,006	11,970	11,935	11,900	11,865	11,829	11,795	143,853		143,853
	i.	Big Bend Unit 2 Classifier Replacement	8,806	8,782	8,757	8,732	8,708	8,683	8,658	8,633	8,609	8,584	8,559	8,535	104,046		104,046
	j.	Big Bend Section 114 Mercury Testing Platform	1,166	1,163	1,162	1,159	1,158	1,156	1,154	1,152	1,150	1,148	1,146	1,144	13,858		13,858
	k.	Big Bend Units 1 & 2 FGD	750,451	748,492	746,532	744,573	742,637	741,193	741,160	740,684	738,819	737,109	738,520	746,237	8,916,407		8,916,407
	l.	Big Bend FGD Optimization and Utilization	218,109	217,704	217,301	216,897	216,493	216,089	215,684	215,280	214,876	214,473	214,069	213,664	2,590,639		2,590,639
	m.	Big Bend NO_x Emissions Reduction	66,231	66,150	66,069	66,004	65,954	65,903	65,939	66,456	67,136	67,342	67,202	67,057	797,443		797,443
	n.	Big Bend PM Minimization and Monitoring	90,591	90,396	90,199	90,004	89,807	89,612	89,415	89,220	89,075	89,082	89,109	89,161	1,075,671		1,075,671
	o.	Polk NO_x Emissions Reduction	17,559	17,517	17,473	17,431	17,388	17,345	17,302	17,258	17,216	17,173	17,130	17,087	207,879		207,879
	p.	Big Bend Unit 4 SOFA	27,948	27,898	27,848	27,799	27,749	27,699	27,650	27,600	27,551	27,501	27,451	27,402	332,096		332,096
	q.	Big Bend Unit 1 Pre-SCR	23,579	23,539	23,499	23,451	23,401	23,357	23,313	23,269	23,225	23,181	23,137	23,093	280,044		280,044
	r.	Big Bend Unit 2 Pre-SCR	18,960	18,921	18,881	18,841	18,802	18,762	18,723	18,683	18,643	18,604	18,564	18,525	224,909		224,909
	s.	Big Bend Unit 3 Pre-SCR	22,793	25,253	25,918	29,315	32,464	32,031	31,975	32,386	32,337	32,282	32,226	32,168	361,148		361,148
	t.	Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	u.	Big Bend Unit 2 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	v	Big Bend Unit 3 SCR	0	0	0	0	0	0	815,255	923,533	922,724	921,641	920,542	920,130	5,423,825		5,423,825
	w.	Big Bend Unit 4 SCR	707,557	706,732	705,859	705,392	702,934	700,469	699,413	698,254	697,070	695,882	694,694	693,507	8,407,763		8,407,763
	x.	Big Bend FGD System Reliability	110,065	114,980	117,554	125,303	132,098	132,395	132,498	132,528	132,470	132,351	132,117	131,888	1,526,247		1,526,247
	y.	Clean Air Mercury Rule	1,934	3,617	5,799	6,334	6,383	6,412	6,434	6,466	6,537	6,607	6,733	8,353	71,609		71,609
	z.	SO_2 Emissions Allowances (B)	(648)	(616)	(603)	(590)	(577)	(564)	(550)	(534)	(494)	(453)	(445)	(439)	(6,513)		(6,513)
2.		Total Investment Projects - Recoverable Costs	2,205,269	2,210,332	2,211,685	2,219,721	2,224,108	2,218,890	3,032,005	3,138,486	3,134,195	3,129,398	3,127,277	3,133,674	31,985,040	$ 163,872	$ 31,821,168
3.		Recoverable Costs Allocated to Energy	2,191,441	2,196,536	2,197,921	2,205,986	2,210,406	2,205,218	3,018,364	3,124,877	3,120,618	3,115,850	3,113,762	3,120,189	31,821,168		
4.		Recoverable Costs Allocated to Demand	13,828	13,796	13,764	13,735	13,702	13,672	13,641	13,609	13,577	13,548	13,515	13,485	163,872		
5.		Retail Energy Jurisdictional Factor	0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701			
6.		Retail Demand Jurisdictional Factor	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743			
7.		Jurisdictional Energy Recoverable Costs (C)	2,120,937	2,096,972	2,106,711	2,092,449	2,102,781	2,135,851	2,905,822	2,997,626	3,001,380	3,016,363	3,022,422	3,054,260	30,653,574		
8.		Jurisdictional Demand Recoverable Costs (D)	13,367	13,336	13,305	13,277	13,245	13,216	13,186	13,155	13,125	13,097	13,065	13,036	158,410		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$2,134,304	$2,110,308	$2,120,016	$2,105,726	$2,116,026	$2,149,067	$2,919,008	$3,010,781	$3,014,505	$3,029,460	$3,035,487	$3,067,296	$30,811,984		

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 page 26, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 7, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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	$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)	$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	(2,832,261)	(2,848,054)	(2,863,847)	(2,879,640)	(2,895,433)	(2,911,226)	(2,927,019)	(2,942,812)	(2,958,605)	(2,974,398)	(2,990,191)	(3,005,984)	(3,021,777)	
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)	$5,407,397	5,391,604	5,375,811	5,360,018	5,344,225	5,328,432	5,312,639	5,296,846	5,281,053	5,265,260	5,249,467	5,233,674	5,217,881	
6.	Average Net Investment		5,399,501	5,383,708	5,367,915	5,352,122	5,336,329	5,320,536	5,304,743	5,288,950	5,273,157	5,257,364	5,241,571	5,225,778	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		39,703	39,587	39,471	39,355	39,239	39,123	39,007	38,891	38,774	38,658	38,542	38,426	$468,776
	b. Debt Component (Line 6 x 2.82% x 1/12)		12,689	12,652	12,615	12,577	12,540	12,503	12,466	12,429	12,392	12,355	12,318	12,281	149,817
8.	Investment Expenses														
	a. Depreciation (C)		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)		68,185	68,032	67,879	67,725	67,572	67,419	67,266	67,113	66,959	66,806	66,653	66,500	808,109
	a. Recoverable Costs Allocated to Energy		68,185	68,032	67,879	67,725	67,572	67,419	67,266	67,113	66,959	66,806	66,653	66,500	808,109
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		65,991	64,948	65,062	64,239	64,282	65,298	64,758	64,380	64,401	64,673	64,698	65,095	777,825
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$65,991	$64,948	$65,062	$64,239	$64,282	$65,298	$64,758	$64,380	$64,401	$64,673	$64,698	$65,095	$777,825

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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ECRC 2008 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 2008 to December 2008

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	(2,373,494)	(2,386,903)	(2,400,312)	(2,413,721)	(2,427,130)	(2,440,539)	(2,453,948)	(2,467,357)	(2,480,766)	(2,494,175)	(2,507,584)	(2,520,993)	(2,534,402)	
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) (B)	$2,644,240	2,630,831	2,617,422	2,604,013	2,590,604	2,577,195	2,563,786	2,550,377	2,536,968	2,523,559	2,510,150	2,496,741	2,483,332	
6.	Average Net Investment		2,637,536	2,624,127	2,610,718	2,597,309	2,583,900	2,570,491	2,557,082	2,543,673	2,530,264	2,516,855	2,503,446	2,490,037	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		19,394	19,296	19,197	19,098	19,000	18,901	18,803	18,704	18,605	18,507	18,408	18,310	$226,223
	b. Debt Component (Line 6 x 2.82% x 1/12)		6,198	6,167	6,135	6,104	6,072	6,041	6,009	5,978	5,946	5,915	5,883	5,852	72,300
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)		39,001	38,872	38,741	38,611	38,481	38,351	38,221	38,091	37,960	37,831	37,700	37,571	459,431
	a. Recoverable Costs Allocated to Energy		39,001	38,872	38,741	38,611	38,481	38,351	38,221	38,091	37,960	37,831	37,700	37,571	459,431
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (E)		37,746	37,110	37,133	36,624	36,607	37,145	36,796	36,540	36,510	36,623	36,594	36,777	442,205
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)		$37,746	$37,110	$37,133	$36,624	$36,607	$37,145	$36,796	$36,540	$36,510	$36,623	$36,594	$36,777	$442,205

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 3.3% 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 2008 to December 2008

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	(303,077)	(304,593)	(306,109)	(307,625)	(309,141)	(310,657)	(312,173)	(313,689)	(315,205)	(316,721)	(318,237)	(319,753)	(321,269)	
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)	$563,134	561,618	560,102	558,586	557,070	555,554	554,038	552,522	551,006	549,490	547,974	546,458	544,942	
6.	Average Net Investment		562,376	560,860	559,344	557,828	556,312	554,796	553,280	551,764	550,248	548,732	547,216	545,700	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,135	4,124	4,113	4,102	4,091	4,080	4,068	4,057	4,046	4,035	4,024	4,013	$48,888
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,322	1,318	1,314	1,311	1,307	1,304	1,300	1,297	1,293	1,290	1,286	1,282	15,624
8.	Investment Expenses														
	a. Depreciation (C)		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)		6,973	6,958	6,943	6,929	6,914	6,900	6,884	6,870	6,855	6,841	6,826	6,811	82,704
	a. Recoverable Costs Allocated to Energy		6,973	6,958	6,943	6,929	6,914	6,900	6,884	6,870	6,855	6,841	6,826	6,811	82,704
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		6,749	6,643	6,655	6,572	6,577	6,683	6,627	6,590	6,593	6,623	6,626	6,667	79,605
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,749	$6,643	$6,655	$6,572	$6,577	$6,683	$6,627	$6,590	$6,593	$6,623	$6,626	$6,667	$79,605

Notes:

(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.1%
(D) Line 9a x Line 10
(E) 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 2008 to December 2008

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	(120,688)	(121,766)	(122,844)	(123,922)	(125,000)	(126,078)	(127,156)	(128,234)	(129,312)	(130,390)	(131,468)	(132,546)	(133,624)	
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)	$376,890	375,812	374,734	373,656	372,578	371,500	370,422	369,344	368,266	367,188	366,110	365,032	363,954	
6.	Average Net Investment		376,351	375,273	374,195	373,117	372,039	370,961	369,883	368,805	367,727	366,649	365,571	364,493	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,767	2,759	2,752	2,744	2,736	2,728	2,720	2,712	2,704	2,696	2,688	2,680	$32,686
	b. Debt Component (Line 6 x 2.82% x 1/12)		884	882	879	877	874	872	869	867	864	862	859	857	10,446
8.	Investment Expenses														
	a. Depreciation (C)		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)		4,729	4,719	4,709	4,699	4,688	4,678	4,667	4,657	4,646	4,636	4,625	4,615	56,068
	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		4,729	4,719	4,709	4,699	4,688	4,678	4,667	4,657	4,646	4,636	4,625	4,615	56,068
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		4,571	4,562	4,552	4,542	4,532	4,522	4,511	4,502	4,491	4,482	4,471	4,461	54,199
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,571	$4,562	$4,552	$4,542	$4,532	$4,522	$4,511	$4,502	$4,491	$4,482	$4,471	$4,461	$54,199

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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	(198,520)	(200,293)	(202,066)	(203,839)	(205,612)	(207,385)	(209,158)	(210,931)	(212,704)	(214,477)	(216,250)	(218,023)	(219,796)	
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)	$619,881	618,108	616,335	614,562	612,789	611,016	609,243	607,470	605,697	603,924	602,151	600,378	598,605	
6.	Average Net Investment		618,995	617,222	615,449	613,676	611,903	610,130	608,357	606,584	604,811	603,038	601,265	599,492	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,552	4,539	4,525	4,512	4,499	4,486	4,473	4,460	4,447	4,434	4,421	4,408	$53,756
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,455	1,450	1,446	1,442	1,438	1,434	1,430	1,425	1,421	1,417	1,413	1,409	17,180
8.	Investment Expenses														
	a. Depreciation (C)		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)		7,780	7,762	7,744	7,727	7,710	7,693	7,676	7,658	7,641	7,624	7,607	7,590	92,212
	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		7,780	7,762	7,744	7,727	7,710	7,693	7,676	7,658	7,641	7,624	7,607	7,590	92,212
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		7,521	7,503	7,486	7,469	7,453	7,437	7,420	7,403	7,386	7,370	7,353	7,337	89,138
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,521	$7,503	$7,486	$7,469	$7,453	$7,437	$7,420	$7,403	$7,386	$7,370	$7,353	$7,337	$89,138

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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	(19,104)	(19,247)	(19,390)	(19,533)	(19,676)	(19,819)	(19,962)	(20,105)	(20,248)	(20,391)	(20,534)	(20,677)	(20,820)	
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)	$38,173	38,030	37,887	37,744	37,601	37,458	37,315	37,172	37,029	36,886	36,743	36,600	36,457	
6.	Average Net Investment		38,102	37,959	37,816	37,673	37,530	37,387	37,244	37,101	36,958	36,815	36,672	36,529	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		280	279	278	277	276	275	274	273	272	271	270	269	$3,294
	b. Debt Component (Line 6 x 2.82% x 1/12)		90	89	89	89	88	88	88	87	87	87	86	86	1,054
8.	Investment Expenses														
	a. Depreciation (C)		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)		513	511	510	509	507	506	505	503	502	501	499	498	6,064
	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		513	511	510	509	507	506	505	503	502	501	499	498	6,064
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		496	494	493	492	490	489	488	486	485	484	482	481	5,860
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$496	$494	$493	$492	$490	$489	$488	$486	$485	$484	$482	$481	$5,860

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

DOCKET NO. 090007-EI
ECRC 2008 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 2008 to December 2008

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	(30,587)	(30,813)	(31,039)	(31,265)	(31,491)	(31,717)	(31,943)	(32,169)	(32,395)	(32,621)	(32,847)	(33,073)	(33,299)	
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)	$59,885	59,659	59,433	59,207	58,981	58,755	58,529	58,303	58,077	57,851	57,625	57,399	57,173	
6.	Average Net Investment		59,772	59,546	59,320	59,094	58,868	58,642	58,416	58,190	57,964	57,738	57,512	57,286	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		440	438	436	435	433	431	430	428	426	425	423	421	$5,166
	b. Debt Component (Line 6 x 2.82% x 1/12)		140	140	139	139	138	138	137	137	136	136	135	135	1,650
8.	Investment Expenses														
	a. Depreciation (C)		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)		806	804	801	800	797	795	793	791	788	787	784	782	9,528
	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		806	804	801	800	797	795	793	791	788	787	784	782	9,528
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		779	777	774	773	770	769	767	765	762	761	758	756	9,211
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$779	$777	$774	$773	$770	$769	$767	$765	$762	$761	$758	$756	$9,211

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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	(432,152)	(435,772)	(439,392)	(443,012)	(446,632)	(450,252)	(453,872)	(457,492)	(461,112)	(464,732)	(468,352)	(471,972)	(475,592)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$884,105	880,485	876,865	873,245	869,625	866,005	862,385	858,765	855,145	851,525	847,905	844,285	840,665	
6.	Average Net Investment		882,295	878,675	875,055	871,435	867,815	864,195	860,575	856,955	853,335	849,715	846,095	842,475	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,488	6,461	6,434	6,408	6,381	6,355	6,328	6,301	6,275	6,248	6,221	6,195	$76,095
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,073	2,065	2,056	2,048	2,039	2,031	2,022	2,014	2,005	1,997	1,988	1,980	24,318
8.	Investment Expenses														
	a. Depreciation (C)		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)		12,181	12,146	12,110	12,076	12,040	12,006	11,970	11,935	11,900	11,865	11,829	11,795	143,853
	a. Recoverable Costs Allocated to Energy		12,181	12,146	12,110	12,076	12,040	12,006	11,970	11,935	11,900	11,865	11,829	11,795	143,853
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		11,789	11,595	11,607	11,454	11,454	11,628	11,524	11,449	11,445	11,486	11,482	11,546	138,459
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,789	$11,595	$11,607	$11,454	$11,454	$11,628	$11,524	$11,449	$11,445	$11,486	$11,482	$11,546	$138,459

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

DOCKET NO. 090007-EI
ECRC 2008 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 2008 to December 2008

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	(338,166)	(340,710)	(343,254)	(345,798)	(348,342)	(350,886)	(353,430)	(355,974)	(358,518)	(361,062)	(363,606)	(366,150)	(368,694)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$646,628	644,084	641,540	638,996	636,452	633,908	631,364	628,820	626,276	623,732	621,188	618,644	616,100	
6.	Average Net Investment		645,356	642,812	640,268	637,724	635,180	632,636	630,092	627,548	625,004	622,460	619,916	617,372	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,745	4,727	4,708	4,689	4,671	4,652	4,633	4,614	4,596	4,577	4,558	4,540	$55,710
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,517	1,511	1,505	1,499	1,493	1,487	1,481	1,475	1,469	1,463	1,457	1,451	17,808
8.	Investment Expenses														
	a. Depreciation (C)		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)		8,806	8,782	8,757	8,732	8,708	8,683	8,658	8,633	8,609	8,584	8,559	8,535	104,046
	a. Recoverable Costs Allocated to Energy		8,806	8,782	8,757	8,732	8,708	8,683	8,658	8,633	8,609	8,584	8,559	8,535	104,046
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		8,523	8,384	8,394	8,283	8,284	8,410	8,335	8,281	8,280	8,310	8,308	8,355	100,147
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,523	$8,384	$8,394	$8,283	$8,284	$8,410	$8,335	$8,281	$8,280	$8,310	$8,308	$8,355	$100,147

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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	(21,235)	(21,436)	(21,637)	(21,838)	(22,039)	(22,240)	(22,441)	(22,642)	(22,843)	(23,044)	(23,245)	(23,446)	(23,647)	
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)	$99,502	99,301	99,100	98,899	98,698	98,497	98,296	98,095	97,894	97,693	97,492	97,291	97,090	
6.	Average Net Investment		99,402	99,201	99,000	98,799	98,598	98,397	98,196	97,995	97,794	97,593	97,392	97,191	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		731	729	728	726	725	724	722	721	719	718	716	715	$8,674
	b. Debt Component (Line 6 x 2.82% x 1/12)		234	233	233	232	232	231	231	230	230	229	229	228	2,772
8.	Investment Expenses														
	a. Depreciation (C)		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)		1,166	1,163	1,162	1,159	1,158	1,156	1,154	1,152	1,150	1,148	1,146	1,144	13,858
	a. Recoverable Costs Allocated to Energy		1,166	1,163	1,162	1,159	1,158	1,156	1,154	1,152	1,150	1,148	1,146	1,144	13,858
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		1,128	1,110	1,114	1,099	1,102	1,120	1,111	1,105	1,106	1,111	1,112	1,120	13,338
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,128	$1,110	$1,114	$1,099	$1,102	$1,120	$1,111	$1,105	$1,106	$1,111	$1,112	$1,120	$13,338

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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ECRC 2008 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 2008 to December 2008

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		$0	$0	$0	$0	$4,739	$101,681	$295,181	$10,638	$8,782	$42,614	$651,422	$1,342,633	$2,457,690
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	2,390	0	2,390
	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)	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,555,351	$83,555,351	
3.	Less: Accumulated Depreciation	(26,920,908)	(27,122,828)	(27,324,748)	(27,526,668)	(27,728,588)	(27,930,508)	(28,132,428)	(28,334,348)	(28,536,268)	(28,738,188)	(28,940,108)	(29,142,031)	(29,343,956)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	4,739	106,420	401,601	412,239	421,021	463,635	1,112,667	2,455,300	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$56,632,053	56,430,133	56,228,213	56,026,293	55,824,373	55,627,191	55,526,952	55,620,214	55,428,932	55,235,794	55,076,488	55,525,987	56,666,695	
6.	Average Net Investment		56,531,093	56,329,173	56,127,253	55,925,333	55,725,782	55,577,071	55,573,583	55,524,573	55,332,363	55,156,141	55,301,237	56,096,341	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		415,683	414,198	412,713	411,228	409,761	408,667	408,642	408,281	406,868	405,572	406,639	412,486	$4,920,738
	b. Debt Component (Line 6 x 2.82% x 1/12)		132,848	132,374	131,899	131,425	130,956	130,606	130,598	130,483	130,031	129,617	129,958	131,826	1,572,621
8.	Investment Expenses														
	a. Depreciation (D)		201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,923	201,925	2,423,048
	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)		750,451	748,492	746,532	744,573	742,637	741,193	741,160	740,684	738,819	737,109	738,520	746,237	8,916,407
	a. Recoverable Costs Allocated to Energy		750,451	748,492	746,532	744,573	742,637	741,193	741,160	740,684	738,819	737,109	738,520	746,237	8,916,407
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (E)		726,307	714,564	715,552	706,251	706,478	717,878	713,525	710,522	710,589	713,574	716,856	730,469	8,582,565
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)		$726,307	$714,564	$715,552	$706,251	$706,478	$717,878	$713,525	$710,522	$710,589	$713,574	$716,856	$730,469	$8,582,565

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2008 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 2008 to December 2008

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	(3,532,381)	(3,574,023)	(3,615,665)	(3,657,307)	(3,698,949)	(3,740,591)	(3,782,233)	(3,823,875)	(3,865,517)	(3,907,159)	(3,948,801)	(3,990,443)	(4,032,085)	
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) (B)	$18,207,356	18,165,714	18,124,072	18,082,430	18,040,788	17,999,146	17,957,504	17,915,862	17,874,220	17,832,578	17,790,936	17,749,294	17,707,652	
6.	Average Net Investment		18,186,535	18,144,893	18,103,251	18,061,609	18,019,967	17,978,325	17,936,683	17,895,041	17,853,399	17,811,757	17,770,115	17,728,473	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		133,729	133,422	133,116	132,810	132,504	132,198	131,891	131,585	131,279	130,973	130,667	130,360	$1,584,534
	b. Debt Component (Line 6 x 2.82% x 1/12)		42,738	42,640	42,543	42,445	42,347	42,249	42,151	42,053	41,955	41,858	41,760	41,662	506,401
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)		218,109	217,704	217,301	216,897	216,493	216,089	215,684	215,280	214,876	214,473	214,069	213,664	2,590,639
	a. Recoverable Costs Allocated to Energy		218,109	217,704	217,301	216,897	216,493	216,089	215,684	215,280	214,876	214,473	214,069	213,664	2,590,639
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (E)		211,092	207,836	208,283	205,734	205,952	209,292	207,642	206,513	206,666	207,625	207,789	209,149	2,493,573
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)		$211,092	$207,836	$208,283	$205,734	$205,952	$209,292	$207,642	$206,513	$206,666	$207,625	$207,789	$209,149	$2,493,573

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(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 2008 to December 2008

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	$2,745	$2,352	$2,803	$16,829	$84,267	$44,311	$4,501	($14,161)	$3,927	$147,574
	b. Clearings to Plant		0	0	0	2,745	2,352	2,803	16,829	84,267	44,311	4,501	(14,161)	3,927	$147,574
	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)	$3,190,853	$3,190,853	$3,190,853	$3,190,853	$3,193,598	$3,195,950	$3,198,753	$3,215,582	$3,299,849	$3,344,160	$3,348,661	$3,334,500	$3,338,427	
3.	Less: Accumulated Depreciation	2,779,586	2,771,247	2,762,908	2,754,569	2,746,227	2,737,879	2,729,526	2,721,151	2,712,667	2,704,044	2,695,368	2,686,702	2,678,047	
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) (B)	$5,970,439	5,962,100	5,953,761	5,945,422	5,939,825	5,933,829	5,928,279	5,936,733	6,012,516	6,048,204	6,044,029	6,021,202	6,016,474	
6.	Average Net Investment		5,966,270	5,957,931	5,949,592	5,942,624	5,936,827	5,931,054	5,932,506	5,974,625	6,030,360	6,046,117	6,032,616	6,018,838	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		43,871	43,810	43,748	43,697	43,654	43,612	43,623	43,932	44,342	44,458	44,359	44,258	$527,364
	b. Debt Component (Line 6 x 2.82% x 1/12)		14,021	14,001	13,982	13,965	13,952	13,938	13,941	14,040	14,171	14,208	14,177	14,144	168,540
8.	Investment Expenses														
	a. Depreciation (D)		8,339	8,339	8,339	8,342	8,348	8,353	8,375	8,484	8,623	8,676	8,666	8,655	101,539
	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)		66,231	66,150	66,069	66,004	65,954	65,903	65,939	66,456	67,136	67,342	67,202	67,057	797,443
	a. Recoverable Costs Allocated to Energy		66,231	66,150	66,069	66,004	65,954	65,903	65,939	66,456	67,136	67,342	67,202	67,057	797,443
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (E)		64,100	63,152	63,327	62,607	62,743	63,830	63,480	63,750	64,571	65,192	65,231	65,640	767,623
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)		$64,100	$63,152	$63,327	$62,607	$62,743	$63,830	$63,480	$63,750	$64,571	$65,192	$65,231	$65,640	$767,623

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($587,538)
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(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 2008 to December 2008

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		$0	$0	$0	$0	$0	$0	$0	$0	$10,663	$31,128	$14,944	$35,892	$92,627
	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)	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	
3.	Less: Accumulated Depreciation	(725,979)	(746,174)	(766,369)	(786,564)	(806,759)	(826,954)	(847,149)	(867,344)	(887,539)	(907,734)	(927,929)	(948,124)	(968,319)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	10,663	41,791	56,735	92,627	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$7,265,073	7,244,878	7,224,683	7,204,488	7,184,293	7,164,098	7,143,903	7,123,708	7,103,513	7,093,981	7,104,914	7,099,663	7,115,360	
6.	Average Net Investment		7,254,976	7,234,781	7,214,586	7,194,391	7,174,196	7,154,001	7,133,806	7,113,611	7,098,747	7,099,448	7,102,289	7,107,512	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		53,347	53,199	53,050	52,902	52,753	52,605	52,456	52,308	52,198	52,203	52,224	52,263	$631,508
	b. Debt Component (Line 6 x 2.82% x 1/12)		17,049	17,002	16,954	16,907	16,859	16,812	16,764	16,717	16,682	16,684	16,690	16,703	201,823
8.	Investment Expenses														
	a. Depreciation (D)		20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	242,340
	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)		90,591	90,396	90,199	90,004	89,807	89,612	89,415	89,220	89,075	89,082	89,109	89,161	1,075,671
	a. Recoverable Costs Allocated to Energy		90,591	90,396	90,199	90,004	89,807	89,612	89,415	89,220	89,075	89,082	89,109	89,161	1,075,671
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (E)		87,676	86,299	86,456	85,372	85,434	86,793	86,081	85,587	85,671	86,238	86,495	87,277	1,035,379
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)		$87,676	$86,299	$86,456	$85,372	$85,434	$86,793	$86,081	$85,587	$85,671	$86,238	$86,495	$87,277	$1,035,379

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), and 315.44 ($351,594)
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, and 2.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 090007-EI
ECRC 2008 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 2008 to December 2008

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	(205,530)	(209,954)	(214,378)	(218,802)	(223,226)	(227,650)	(232,074)	(236,498)	(240,922)	(245,346)	(249,770)	(254,194)	(258,618)	
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)	$1,355,943	1,351,519	1,347,095	1,342,671	1,338,247	1,333,823	1,329,399	1,324,975	1,320,551	1,316,127	1,311,703	1,307,279	1,302,855	
6.	Average Net Investment		1,353,731	1,349,307	1,344,883	1,340,459	1,336,035	1,331,611	1,327,187	1,322,763	1,318,339	1,313,915	1,309,491	1,305,067	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,954	9,922	9,889	9,857	9,824	9,792	9,759	9,726	9,694	9,661	9,629	9,596	$117,303
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,181	3,171	3,160	3,150	3,140	3,129	3,119	3,108	3,098	3,088	3,077	3,067	37,488
8.	Investment Expenses														
	a. Depreciation (C)		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)		17,559	17,517	17,473	17,431	17,388	17,345	17,302	17,258	17,216	17,173	17,130	17,087	207,879
	a. Recoverable Costs Allocated to Energy		17,559	17,517	17,473	17,431	17,388	17,345	17,302	17,258	17,216	17,173	17,130	17,087	207,879
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		16,994	16,723	16,748	16,534	16,541	16,799	16,657	16,555	16,558	16,625	16,628	16,726	200,088
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,994	$16,723	$16,748	$16,534	$16,541	$16,799	$16,657	$16,555	$16,558	$16,625	$16,628	$16,726	$200,088

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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	(203,234)	(208,351)	(213,468)	(218,585)	(223,702)	(228,819)	(233,936)	(239,053)	(244,170)	(249,287)	(254,404)	(259,521)	(264,638)	
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)	$2,355,496	2,350,379	2,345,262	2,340,145	2,335,028	2,329,911	2,324,794	2,319,677	2,314,560	2,309,443	2,304,326	2,299,209	2,294,092	
6.	Average Net Investment		2,352,938	2,347,821	2,342,704	2,337,587	2,332,470	2,327,353	2,322,236	2,317,119	2,312,002	2,306,885	2,301,768	2,296,651	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		17,302	17,264	17,226	17,189	17,151	17,113	17,076	17,038	17,001	16,963	16,925	16,888	$205,136
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,529	5,517	5,505	5,493	5,481	5,469	5,457	5,445	5,433	5,421	5,409	5,397	65,556
8.	Investment Expenses														
	a. Depreciation (C)		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)		27,948	27,898	27,848	27,799	27,749	27,699	27,650	27,600	27,551	27,501	27,451	27,402	332,096
	a. Recoverable Costs Allocated to Energy		27,948	27,898	27,848	27,799	27,749	27,699	27,650	27,600	27,551	27,501	27,451	27,402	332,096
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		27,049	26,633	26,692	26,368	26,398	26,828	26,619	26,476	26,498	26,623	26,646	26,823	319,653
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$27,049	$26,633	$26,692	$26,368	$26,398	$26,828	$26,619	$26,476	$26,498	$26,623	$26,646	$26,823	$319,653

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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ECRC 2008 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 2008 to December 2008

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		$437	$346	$417	($1,176)	($28)	$0	$0	$0	$0	$0	$0	$0	($4)
	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	(52,165)	(56,700)	(61,235)	(65,770)	(70,305)	(74,840)	(79,375)	(83,910)	(88,445)	(92,980)	(97,515)	(102,050)	(106,585)	
4.	CWIP - Non-Interest Bearing	367,771	368,208	368,554	368,971	367,795	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	
5.	Net Investment (Lines 2 + 3 + 4)	$1,964,727	1,960,629	1,956,440	1,952,322	1,946,611	1,942,048	1,937,513	1,932,978	1,928,443	1,923,908	1,919,373	1,914,838	1,910,303	
6.	Average Net Investment		1,962,678	1,958,535	1,954,381	1,949,467	1,944,330	1,939,781	1,935,246	1,930,711	1,926,176	1,921,641	1,917,106	1,912,571	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,432	14,401	14,371	14,335	14,297	14,264	14,230	14,197	14,163	14,130	14,097	14,063	$170,980
	b. Debt Component (Line 6 x 2.82% x 1/12)		4,612	4,603	4,593	4,581	4,569	4,558	4,548	4,537	4,527	4,516	4,505	4,495	54,644
8.	Investment Expenses														
	a. Depreciation (C)		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)		23,579	23,539	23,499	23,451	23,401	23,357	23,313	23,269	23,225	23,181	23,137	23,093	280,044
	a. Recoverable Costs Allocated to Energy		23,579	23,539	23,499	23,451	23,401	23,357	23,313	23,269	23,225	23,181	23,137	23,093	280,044
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		22,820	22,472	22,524	22,244	22,262	22,622	22,444	22,321	22,338	22,441	22,458	22,605	269,551
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$22,820	$22,472	$22,524	$22,244	$22,262	$22,622	$22,444	$22,321	$22,338	$22,441	$22,458	$22,605	$269,551

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) 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 2008 to December 2008

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	$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	(47,000)	(51,087)	(55,174)	(59,261)	(63,348)	(67,435)	(71,522)	(75,609)	(79,696)	(83,783)	(87,870)	(91,957)	(96,044)	
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)	$1,534,887	1,530,800	1,526,713	1,522,626	1,518,539	1,514,452	1,510,365	1,506,278	1,502,191	1,498,104	1,494,017	1,489,930	1,485,843	
6.	Average Net Investment		1,532,844	1,528,757	1,524,670	1,520,583	1,516,496	1,512,409	1,508,322	1,504,235	1,500,148	1,496,061	1,491,974	1,487,887	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		11,271	11,241	11,211	11,181	11,151	11,121	11,091	11,061	11,031	11,001	10,971	10,941	$133,272
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,602	3,593	3,583	3,573	3,564	3,554	3,545	3,535	3,525	3,516	3,506	3,497	42,593
8.	Investment Expenses														
	a. Depreciation (C)		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)		18,960	18,921	18,881	18,841	18,802	18,762	18,723	18,683	18,643	18,604	18,564	18,525	224,909
	a. Recoverable Costs Allocated to Energy		18,960	18,921	18,881	18,841	18,802	18,762	18,723	18,683	18,643	18,604	18,564	18,525	224,909
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		18,350	18,063	18,097	17,871	17,887	18,172	18,025	17,922	17,931	18,010	18,019	18,134	216,481
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,350	$18,063	$18,097	$17,871	$17,887	$18,172	$18,025	$17,922	$17,931	$18,010	$18,019	$18,134	$216,481

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) 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 2008 to December 2008

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		$432,404	$74,612	$62,487	$35,386	$14,020	($77,358)	$77,381	$1,410	$83	$207	$0	$0	$620,632
	b. Clearings to Plant		0	0	0	2,737,764	14,020	(77,358)	77,381	1,410	83	207	0	0	2,753,507
	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)	$0	$0	$0	$0	$2,737,764	$2,751,784	$2,674,426	$2,751,807	$2,753,217	$2,753,300	$2,753,507	$2,753,507	$2,753,507	
3.	Less: Accumulated Depreciation	0	0	0	0	(2,936)	(8,824)	(14,643)	(20,462)	(26,367)	(32,273)	(38,180)	(44,087)	(49,994)	
4.	CWIP - Non-Interest Bearing	2,132,875	2,565,279	2,639,891	2,702,378	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,132,875	2,565,279	2,639,891	2,702,378	2,734,828	2,742,960	2,659,783	2,731,345	2,726,850	2,721,027	2,715,327	2,709,420	2,703,513	
6.	Average Net Investment		2,349,077	2,602,585	2,671,135	2,718,603	2,738,894	2,701,372	2,695,564	2,729,098	2,723,939	2,718,177	2,712,374	2,706,467	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		17,273	19,137	19,641	19,990	20,140	19,864	19,821	20,068	20,030	19,987	19,945	19,901	$235,797
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,520	6,116	6,277	6,389	6,436	6,348	6,335	6,413	6,401	6,388	6,374	6,360	75,357
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	2,936	5,888	5,819	5,819	5,905	5,906	5,907	5,907	5,907	49,994
	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)		22,793	25,253	25,918	29,315	32,464	32,031	31,975	32,386	32,337	32,282	32,226	32,168	361,148
	a. Recoverable Costs Allocated to Energy		22,793	25,253	25,918	29,315	32,464	32,031	31,975	32,386	32,337	32,282	32,226	32,168	361,148
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		22,060	24,108	24,842	27,806	30,883	31,023	30,783	31,067	31,101	31,251	31,281	31,488	347,693
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$22,060	$24,108	$24,842	$27,806	$30,883	$31,023	$30,783	$31,067	$31,101	$31,251	$31,281	$31,488	$347,693

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($2,042,677) and 315.43 ($710,830)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.6% and 2.5%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 19 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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		$1,561,868	$566,544	$1,051,233	$1,230,140	$1,286,971	$657,362	$846,453	$924,340	$781,293	$2,017,391	$1,079,681	$2,077,772	$14,081,048
	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)	$21,559,050	$23,120,918	$23,687,462	$24,738,695	$25,968,835	$27,255,806	$27,913,168	$28,759,621	$29,683,961	$30,465,254	$32,482,645	$33,562,326	$35,640,098	
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)	$21,559,050	23,120,918	23,687,462	24,738,695	25,968,835	27,255,806	27,913,168	28,759,621	29,683,961	30,465,254	32,482,645	33,562,326	35,640,098	
6.	Average Net Investment		22,339,984	23,404,190	24,213,079	25,353,765	26,612,321	27,584,487	28,336,395	29,221,791	30,074,608	31,473,950	33,022,486	34,601,212	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	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		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)		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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.3% and 2.5%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 20 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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		$1,667,980	$898,673	$4,497,280	$2,409,922	$4,698,872	$2,224,934	$3,046,170	$3,119,163	$3,648,204	$5,293,188	$4,909,859	$4,693,718	$41,107,963
	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)	$29,055,383	$30,723,363	$31,622,036	$36,119,316	$38,529,238	$43,228,110	$45,453,044	$48,499,214	$51,618,377	$55,266,581	$60,559,769	$65,469,628	$70,163,346	
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)	$29,055,383	30,723,363	31,622,036	36,119,316	38,529,238	43,228,110	45,453,044	48,499,214	51,618,377	55,266,581	60,559,769	65,469,628	70,163,346	
6.	Average Net Investment		29,889,373	31,172,700	33,870,676	37,324,277	40,878,674	44,340,577	46,976,129	50,058,796	53,442,479	57,913,175	63,014,699	67,816,487	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	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		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)		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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rates are 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,000
	b. Clearings to Plant		0	0	20,000	0	0	0	0	0	0	0	0	0	$20,000
	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)	$1,153,186	$1,153,186	$1,153,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	
3.	Less: Accumulated Depreciation	(22,605)	(25,488)	(28,371)	(31,254)	(34,187)	(37,120)	(40,053)	(42,986)	(45,919)	(48,852)	(51,785)	(54,718)	(57,651)	
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)	$1,130,581	1,127,698	1,124,815	1,141,932	1,138,999	1,136,066	1,133,133	1,130,200	1,127,267	1,124,334	1,121,401	1,118,468	1,115,535	
6.	Average Net Investment		1,129,140	1,126,257	1,133,374	1,140,466	1,137,533	1,134,600	1,131,667	1,128,734	1,125,801	1,122,868	1,119,935	1,117,002	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,204	8,183	8,235	8,286	8,265	8,244	8,222	8,201	8,180	8,158	8,137	8,116	$98,431
	b. Debt Component Grossed Up For Taxes (F)		2,759	2,752	2,770	2,787	2,780	2,773	2,765	2,758	2,751	2,744	2,737	2,730	33,106
8.	Investment Expenses														
	a. Depreciation (C)		2,883	2,883	2,883	2,933	2,933	2,933	2,933	2,933	2,933	2,933	2,933	2,933	35,046
	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)		13,846	13,818	13,888	14,006	13,978	13,950	13,920	13,892	13,864	13,835	13,807	13,779	166,583
	a. Recoverable Costs Allocated to Energy		13,846	13,818	13,888	14,006	13,978	13,950	13,920	13,892	13,864	13,835	13,807	13,779	166,583
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		13,540	13,442	13,537	13,596	13,459	13,541	13,481	13,400	13,407	13,359	13,403	13,461	161,626
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,540	$13,442	$13,537	$13,596	$13,459	$13,541	$13,481	$13,400	$13,407	$13,359	$13,403	$13,461	$161,626

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 315.40 ($1,173,186) and 345.81
(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 1.63490).
(C) Applicable depreciation rate is 3.3%, 2.6%, 2.4%, 3.0%, and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

DOCKET NO. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3, PAGES 1 - 26
DOCUMENT NO. 4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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		$112,273	($49,818)	$103,703	$20,113	($236,669)	$18,261	$4,266	$493	$0	$0	$0	$0	($27,378)
	b. Clearings to Plant		112,273	(49,818)	103,703	20,113	(236,669)	18,261	4,266	493	0	0	0	0	(27,378)
	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)	$61,210,715	$61,322,988	$61,273,171	$61,376,874	$61,396,987	$61,160,318	$61,178,579	$61,182,845	$61,183,338	$61,183,338	$61,183,338	$61,183,338	$61,183,338	
3.	Less: Accumulated Depreciation	(913,640)	(1,036,174)	(1,158,770)	(1,281,420)	(1,404,194)	(1,526,751)	(1,649,090)	(1,771,451)	(1,893,817)	(2,016,184)	(2,138,551)	(2,260,918)	(2,383,285)	
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)	$60,297,075	60,286,814	60,114,401	60,095,454	59,992,793	59,633,567	59,529,489	59,411,394	59,289,521	59,167,154	59,044,787	58,922,420	58,800,053	
6.	Average Net Investment		60,291,945	60,200,608	60,104,928	60,044,124	59,813,180	59,581,528	59,470,442	59,350,458	59,228,338	59,105,971	58,983,604	58,861,237	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		443,337	442,665	441,962	441,514	439,816	438,113	437,296	436,414	435,516	434,616	433,716	432,816	$5,257,781
	b. Debt Component (Line 6 x 2.82% x 1/12)		141,686	141,471	141,247	141,104	140,561	140,017	139,756	139,474	139,187	138,899	138,611	138,324	1,680,337
8.	Investment Expenses														
	a. Depreciation (C)		122,534	122,596	122,650	122,774	122,557	122,339	122,361	122,366	122,367	122,367	122,367	122,367	1,469,645
	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)		707,557	706,732	705,859	705,392	702,934	700,469	699,413	698,254	697,070	695,882	694,694	693,507	8,407,763
	a. Recoverable Costs Allocated to Energy		707,557	706,732	705,859	705,392	702,934	700,469	699,413	698,254	697,070	695,882	694,694	693,507	8,407,763
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		684,793	674,697	676,567	669,087	668,708	678,435	673,335	669,820	670,435	673,663	674,316	678,853	8,092,709
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$684,793	$674,697	$676,567	$669,087	$668,708	$678,435	$673,335	$669,820	$670,435	$673,663	$674,316	$678,853	$8,092,709

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 23 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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		$739,281	$292,814	$256,943	$85,317	$60,668	$27,303	$27,565	$14,775	$12,324	$4,525	($7,538)	$5,331	$1,519,307
	b. Clearings to Plant		0	0	0	6,418,273	60,603	$27,323	27,565	14,775	12,324	4,525	(7,538)	5,331	6,563,180
	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)	$5,001,604	$5,001,604	$5,001,604	$5,001,604	$11,419,877	$11,480,480	$11,507,803	$11,535,367	$11,550,141	$11,562,465	$11,566,990	$11,559,452	$11,564,783	
3.	Less: Accumulated Depreciation	(71,177)	(80,763)	(90,349)	(99,935)	(115,733)	(137,801)	(159,954)	(182,159)	(204,404)	(226,675)	(248,962)	(271,246)	(293,528)	
4.	CWIP - Non-Interest Bearing	5,060,055	5,799,336	6,092,150	6,349,093	16,137	16,202	16,182	16,182	16,182	16,182	16,182	16,182	16,182	
5.	Net Investment (Lines 2 + 3 + 4)	$9,990,482	10,720,177	11,003,405	11,250,762	11,320,281	11,358,881	11,364,031	11,369,390	11,361,919	11,351,972	11,334,210	11,304,386	11,287,437	
6.	Average Net Investment		10,355,330	10,861,791	11,127,084	11,285,522	11,339,581	11,361,456	11,366,711	11,365,655	11,356,946	11,343,091	11,319,299	11,295,912	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		76,144	79,869	81,819	82,984	83,382	83,543	83,581	83,574	83,510	83,408	83,233	83,061	$988,108
	b. Debt Component (Line 6 x 2.82% x 1/12)		24,335	25,525	26,149	26,521	26,648	26,699	26,712	26,709	26,689	26,656	26,600	26,545	315,788
8.	Investment Expenses														
	a. Depreciation (C)		9,586	9,586	9,586	15,798	22,068	22,153	22,205	22,245	22,271	22,287	22,284	22,282	222,351
	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)		110,065	114,980	117,554	125,303	132,098	132,395	132,498	132,528	132,470	132,351	132,117	131,888	1,526,247
	a. Recoverable Costs Allocated to Energy		110,065	114,980	117,554	125,303	132,098	132,395	132,498	132,528	132,470	132,351	132,117	131,888	1,526,247
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		106,524	109,768	112,676	118,854	125,666	128,230	127,558	127,131	127,408	128,125	128,241	129,101	1,469,282
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$106,524	$109,768	$112,676	$118,854	$125,666	$128,230	$127,558	$127,131	$127,408	$128,125	$128,241	$129,101	$1,469,282

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($10,108,574)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.4% and 2.3%.
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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ECRC 2008 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 2008 to December 2008

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		$1,991	$344,698	$105,208	$4,944	$5,163	$964	$3,550	$3,045	$11,636	$2,804	$23,006	$310,952	$817,961
	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)	$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	198,360	200,351	545,049	650,257	655,201	660,364	661,328	664,878	667,923	679,559	682,363	705,369	1,016,321	
5.	Net Investment (Lines 2 + 3 + 4)	$198,360	200,351	545,049	650,257	655,201	660,364	661,328	664,878	667,923	679,559	682,363	705,369	1,016,321	
6.	Average Net Investment		199,356	372,700	597,653	652,729	657,783	660,846	663,103	666,401	673,741	680,961	693,866	860,845	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		1,466	2,741	4,395	4,800	4,837	4,859	4,876	4,900	4,954	5,007	5,102	6,330	$54,267
	b. Debt Component (Line 6 x 2.82% x 1/12)		468	876	1,404	1,534	1,546	1,553	1,558	1,566	1,583	1,600	1,631	2,023	17,342
8.	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		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)		1,934	3,617	5,799	6,334	6,383	6,412	6,434	6,466	6,537	6,607	6,733	8,353	71,609
	a. Recoverable Costs Allocated to Energy		1,934	3,617	5,799	6,334	6,383	6,412	6,434	6,466	6,537	6,607	6,733	8,353	71,609
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		1,872	3,453	5,558	6,008	6,072	6,210	6,194	6,203	6,287	6,396	6,535	8,177	68,965
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,872	$3,453	$5,558	$6,008	$6,072	$6,210	$6,194	$6,203	$6,287	$6,396	$6,535	$8,177	$68,965

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, and 345.81
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.3%, 2.6%, 2.4%, and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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ECRC 2008 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 2008 to December 2008

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		($1,250)	(12,500)	975,000	(2,500)	1,000,000	0	808,750	0	3,177,500	0	5,199,755	0	11,144,755
	c. Auction Proceeds/Other		0	0	0	0	0	0	638,084	0	0	0	0	0	638,084
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	(69,802)	(63,711)	(63,283)	(61,108)	(60,570)	(58,322)	(57,933)	(55,371)	(54,655)	(47,185)	(46,187)	(45,475)	(44,985)	
3.	Total Working Capital Balance	($69,802)	(63,711)	(63,283)	(61,108)	(60,570)	(58,322)	(57,933)	(55,371)	(54,655)	(47,185)	(46,187)	(45,475)	(44,985)	
4.	Average Net Working Capital Balance		($66,757)	($63,497)	($62,196)	($60,839)	($59,446)	($58,128)	($56,652)	($55,013)	($50,920)	($46,686)	($45,831)	($45,230)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(491)	(467)	(457)	(447)	(437)	(427)	(417)	(405)	(374)	(343)	(337)	(333)	(4,935)
	b. Debt Component (Line 4 x 2.82% x 1/12)		(157)	(149)	(146)	(143)	(140)	(137)	(133)	(129)	(120)	(110)	(108)	(106)	(1,578)
6.	Total Return Component		(648)	(616)	(603)	(590)	(577)	(564)	(550)	(534)	(494)	(453)	(445)	(439)	(6,513)
7.	Expenses:														
	a. Gains		1,250	12,500	(976,697)	2,500	(1,001,697)	0	(1,448,531)	0	(3,184,289)	0	(5,199,755)	0	(11,794,719)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		10,631	16,079	23,333	15,436	16,213	12,269	15,164	5,070	7,148	5,750	5,514	5,919	138,526
8.	Net Expenses (B)		11,881	28,579	(953,364)	17,936	(985,484)	12,269	(1,433,367)	5,070	(3,177,141)	5,750	(5,194,241)	5,919	(11,656,193)
9.	Total System Recoverable Expenses (Lines 6 + 8)		11,233	27,963	(953,967)	17,346	(986,061)	11,705	(1,433,917)	4,536	(3,177,635)	5,297	(5,194,686)	5,480	(11,662,706)
	a. Recoverable Costs Allocated to Energy		11,233	27,963	(953,967)	17,346	(986,061)	11,705	(1,433,917)	4,536	(3,177,635)	5,297	(5,194,686)	5,480	(11,662,706)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (C)		10,872	26,695	(914,379)	16,453	(938,049)	11,337	(1,380,452)	4,351	(3,056,219)	5,128	(5,042,304)	5,364	(11,251,203)
13.	Retail Demand-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		$10,872	$26,695	($914,379)	$16,453	($938,049)	$11,337	($1,380,452)	$4,351	($3,056,219)	$5,128	($5,042,304)	$5,364	($11,251,203)

Notes:
(A) Line 4 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(B) Line 6 is reported on Schedule 6A and 7A
(C) Line 8 is reported on Schedule 4A and 5A
(D) Line 9a x Line 10
(E) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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ECRC 2009 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2

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TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL / ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD OF
JANUARY 2009 THROUGH DECEMBER 2009

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 29
COMPANY Tampa Electric Company (Direct)
WITNESS Howard T. Bryant (HTB-2)
DATE 11/02/09

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2009 to December 2009
(in Dollars)

Form 42 - 1E

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($9,220,766)
2.	Interest Provision (Form 42-2E, Line 6)	(58,363)
3.	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4.	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2010 to December 2010 (Lines 1 + 2 + 3)	($9,279,129)

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DOCKET NO. 090007-EI
ECRC 2009 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 1, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

Form 42 - 2E

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)	$3,325,406	$3,271,914	$2,993,030	$3,046,026	$3,434,524	$3,783,674	$4,304,679	$4,280,633	$4,355,101	$3,923,160	$3,376,046	$3,416,039	$43,510,232
2.	True-Up Provision	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,603	4,711,171
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,718,004	3,664,512	3,385,628	3,438,624	3,827,122	4,176,272	4,697,277	4,673,231	4,747,699	4,315,758	3,768,644	3,808,642	48,221,413
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	1,120,205	1,094,396	1,139,096	1,404,570	897,593	1,105,995	1,273,791	1,473,769	1,601,613	1,682,140	1,440,204	1,921,200	16,154,572
	b. Capital Investment Projects (Form 42-7A, Line 9)	3,103,129	3,099,629	3,106,967	3,093,907	3,079,351	3,073,427	3,011,812	3,438,025	4,067,426	4,053,227	4,069,135	4,091,572	41,287,607
	c. Total Jurisdictional ECRC Costs	4,223,334	4,194,025	4,246,063	4,498,477	3,976,944	4,179,422	4,285,603	4,911,794	5,669,039	5,735,367	5,509,339	6,012,772	57,442,179
5.	Over/Under Recovery (Line 3 - Line 4c)	(505,330)	(529,513)	(860,435)	(1,059,853)	(149,822)	(3,150)	411,674	(238,563)	(921,340)	(1,419,609)	(1,740,695)	(2,204,130)	(9,220,766)
6.	Interest Provision (Form 42-3A, Line 10)	(2,118)	(3,048)	(3,161)	(2,864)	(2,361)	(2,344)	(4,081)	(5,785)	(6,401)	(7,390)	(8,637)	(10,133)	(58,363)
7.	Beginning Balance True-Up & Interest Provision	4,711,171	3,811,125	2,885,966	1,629,772	174,437	(370,364)	(768,456)	(753,461)	(1,390,407)	(2,710,746)	(4,530,343)	(6,672,273)	4,711,171
	a. Deferred True-Up from January to December 2008 (Order No. PSC-xx-xxxx-FOF-EI)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)
8.	True-Up Collected/(Refunded) (see Line 2)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,603)	(4,711,181)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	(4,301,868)	(5,227,027)	(6,483,221)	(7,938,556)	(8,483,357)	(8,881,449)	(8,866,454)	(9,503,400)	(10,823,739)	(12,643,336)	(14,785,266)	(17,392,132)	(17,392,132)
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)	($4,301,868)	($5,227,027)	($6,483,221)	($7,938,556)	($8,483,357)	($8,881,449)	($8,866,454)	($9,503,400)	($10,823,739)	($12,643,336)	($14,785,266)	($17,392,132)	($17,392,132)

DOCKET NO. 090007-EI
ECRC 2009 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 2, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

Form 42 - 3E

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)	($3,401,822)	($4,301,868)	($5,227,027)	($6,483,221)	($7,938,556)	($8,483,357)	($8,881,449)	($8,866,454)	($9,503,400)	($10,823,739)	($12,643,336)	($14,785,266)	
2.	Ending True-Up Amount Before Interest	(4,299,750)	(5,223,979)	(6,480,060)	(7,935,672)	(8,480,976)	(8,879,105)	(8,862,373)	(9,497,615)	(10,817,338)	(12,635,946)	(14,776,629)	(17,381,999)	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	(7,701,572)	(9,525,847)	(11,707,087)	(14,418,893)	(16,419,532)	(17,362,462)	(17,743,822)	(18,364,069)	(20,320,738)	(23,459,685)	(27,419,965)	(32,167,265)	
4.	Average True-Up Amount (Line 3 x 1/2)	(3,850,786)	(4,762,924)	(5,853,544)	(7,209,447)	(8,209,766)	(8,681,231)	(8,871,911)	(9,182,035)	(10,160,369)	(11,729,843)	(13,709,983)	(16,083,633)	
5.	Interest Rate (First Day of Reporting Business Month)	0.54%	0.79%	0.75%	0.55%	0.40%	0.30%	0.35%	0.75%	0.75%	0.75%	0.75%	0.75%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.79%	0.75%	0.55%	0.40%	0.30%	0.35%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.33%	1.54%	1.30%	0.95%	0.70%	0.65%	1.10%	1.50%	1.50%	1.50%	1.50%	1.50%	
8.	Average Interest Rate (Line 7 x 1/2)	0.665%	0.770%	0.650%	0.475%	0.350%	0.325%	0.550%	0.750%	0.750%	0.750%	0.750%	0.750%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.055%	0.064%	0.054%	0.040%	0.029%	0.027%	0.046%	0.063%	0.063%	0.063%	0.063%	0.063%	
10.	Interest Provision for the Month (Line 4 x Line 9)	($2,118)	($3,048)	($3,161)	($2,884)	($2,381)	($2,344)	($4,081)	($5,785)	($6,401)	($7,390)	($8,637)	($10,133)	($58,363)

Tampa Electric Company

Form 42 - 4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	$3,351,790	$3,658,000	($306,210)	-8.4%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	377,496	(12,123,542)	12,501,038	103.1%
	d. Big Bend Units 1 & 2 FGD	8,386,537	7,482,800	903,737	12.1%
	e. Big Bend PM Minimization and Monitoring	467,907	455,000	12,907	2.8%
	f. Big Bend NO_x Emissions Reduction	361,773	358,000	3,773	1.1%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	194,066	50,000	144,066	288.1%
	i. Polk NO_x Emissions Reduction	49,036	75,000	(25,964)	-34.6%
	j. Bayside SCR Consumables	122,057	82,000	40,057	48.9%
	k. Big Bend Unit 4 SOFA	25,718	50,000	(24,282)	-48.6%
	l. Big Bend Unit 1 Pre-SCR	77,000	77,000	0	0.0%
	m. Big Bend Unit 2 Pre-SCR	67,722	77,000	(9,278)	-12.0%
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	47,240	150,000	(102,760)	-68.5%
	p. Arsenic Groundwater Standard Program	115,846	114,000	1,846	1.6%
	q. Big Bend 2 SCR	728,900	1,807,700	(1,078,800)	-59.7%
	r. Big Bend 3 SCR	1,437,288	2,204,900	(767,612)	-34.8%
	s. Big Bend 4 SCR	678,922	1,252,800	(573,878)	-45.8%
	t. Clean Air Mercury Rule	16,255	0	16,255	N/A
2.	Total Investment Projects - Recoverable Costs	$16,540,053	$5,805,158	$10,734,895	-184.9%
3.	Recoverable Costs Allocated to Energy	$16,148,401	$5,456,658	$10,691,743	-195.9%
4.	Recoverable Costs Allocated to Demand	$391,652	$348,500	$43,152	12.4%

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-08-0775-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DOCKET NO. 090007-EI
ECRC 2009 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 4, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	$251,805	$212,491	$232,543	$302,316	$285,328	$212,406	$240,700	$270,000	$401,300	$406,200	$252,000	$284,700	$3,351,790		$3,351,790
	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	6,808	2,253	1,952	1,311	(91,654)	1,005	79,253	79,178	76,550	72,470	71,241	77,129	377,496		377,496
	d. Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	641,230	556,730	621,191	798,241	514,842	674,204	573,100	678,900	761,500	779,800	658,300	1,128,500	8,386,537		8,386,537
	e. Big Bend PM Minimization and Monitoring	40,887	71,601	21,126	28,445	18,636	48,831	36,400	36,400	35,700	44,200	41,500	44,200	467,907		467,907
	f. Big Bend NO_x Emissions Reduction	28,343	89,887	50,001	7,874	9,588	15,700	20,900	20,900	20,200	25,300	27,200	46,100	361,773		361,773
	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	19,115	82,481	0	12,469	60,000	30,000	0	0	10,000	0	194,066	194,066	
	i. Polk NO_x Reduction	2,334	740	1,054	17,310	1,995	4,603	3,500	3,500	3,500	3,500	3,500	3,500	49,036		49,036
	j. Bayside SCR and Ammonia	0	22,768	23,834	0	7,398	8,057	10,001	9,999	9,997	10,002	10,001	10,001	122,057		122,057
	k. Big Bend Unit 4 SOFA	0	0	0	(24,282)	0	0	0	0	0	14,300	35,700	0	25,718		25,718
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	6,900	70,100	77,000		77,000
	m. Big Bend Unit 2 Pre-SCR	16,541	48,806	950	0	0	1,425	0	0	0	0	0	0	67,722		67,722
	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	1,874	0	0	6,872	2,494	0	12,000	12,000	0	0	12,000	0	47,240	47,240	
	p. Arsenic Groundwater Standard Program	0	0	3,823	48,905	3,716	19,902	10,000	0	0	29,500	0	0	115,846	115,846	
	q. Big Bend 2 SCR	0	0	0	0	0	0	0	157,600	153,400	153,700	145,300	118,900	728,900		728,900
	r. Big Bend 3 SCR	74,326	70,010	111,528	102,378	103,782	81,164	186,700	158,000	124,000	154,300	146,000	125,100	1,437,288		1,437,288
	s. Big Bend 4 SCR	34,938	31,205	60,962	70,283	53,751	42,084	81,500	70,000	68,300	47,600	62,300	56,000	678,922		678,922
	t. Clean Air Mercury Rule	0	0	0	0	550	705	2,500	2,500	2,500	2,500	2,500	2,500	16,255		16,255
2.	Total of O&M Activities	1,133,565	1,106,291	1,148,079	1,422,136	910,406	1,122,554	1,316,554	1,528,977	1,656,947	1,743,372	1,484,442	1,966,730	16,540,053	$ 391,652	$ 16,148,400
3.	Recoverable Costs Allocated to Energy	1,097,191	1,106,291	1,125,141	1,303,878	904,196	1,090,182	1,234,554	1,486,977	1,656,947	1,713,872	1,462,442	1,966,730	16,148,401		
4.	Recoverable Costs Allocated to Demand	36,374	0	22,938	118,258	6,210	32,372	82,000	42,000	0	29,500	22,000	0	391,652		
5.	Retail Energy Jurisdictional Factor	0.9891913	0.9892461	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9788498			
6.	Retail Demand Jurisdictional Factor	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232			
7.	Jurisdictional Energy Recoverable Costs (A)	1,085,332	1,094,396	1,117,105	1,291,193	891,639	1,074,959	1,195,176	1,433,503	1,601,613	1,653,856	1,419,112	1,921,200	15,779,086		
8.	Jurisdictional Demand Recoverable Costs (B)	34,873	0	21,991	113,377	5,954	31,036	78,615	40,266	0	28,282	21,092	0	375,486		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,120,205	$1,094,396	$1,139,096	$1,404,570	$897,593	$1,105,995	$1,273,791	$1,473,769	$1,601,613	$1,682,140	$1,440,204	$1,921,200	$16,154,572		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

Form 42 - 6E

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	$786,289	$786,042	$247	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	440,808	440,693	115	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	80,611	80,584	27	0.0%
	d. Big Bend Fuel Oil Tank #1 Upgrade	54,575	54,560	15	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	89,767	89,738	29	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	5,862	5,859	3	0.1%
	g. Phillips Upgrade Tank # 4 for FDEP	9,215	9,211	4	0.0%
	h. Big Bend Unit 1 Classifier Replacement	138,835	138,796	39	0.0%
	i. Big Bend Unit 2 Classifier Replacement	100,518	100,489	29	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	13,584	13,577	7	0.1%
	k. Big Bend Units 1 & 2 FGD	8,921,117	8,960,005	(38,888)	-0.4%
	l. Big Bend FGD Optimization and Utilization	2,533,290	2,532,454	836	0.0%
	m. Big Bend NO_x Emissions Reduction	802,153	793,965	8,188	1.0%
	n. Big Bend PM Minimization and Monitoring	1,086,037	1,124,629	(38,592)	-3.4%
	o. Polk NO_x Emissions Reduction	201,759	201,701	58	0.0%
	p. Big Bend Unit 4 SOFA	325,057	324,949	108	0.0%
	q. Big Bend Unit 1 Pre-SCR	273,776	279,459	(5,683)	-2.0%
	r. Big Bend Unit 2 Pre-SCR	219,267	219,196	71	0.0%
	s. Big Bend Unit 3 Pre-SCR	378,117	370,508	7,609	2.1%
	t. Big Bend Unit 1 SCR	0	0	0	0.0%
	u. Big Bend Unit 2 SCR	4,884,018	8,618,125	(3,734,107)	-43.3%
	v. Big Bend Unit 3 SCR	10,944,895	11,145,102	(200,207)	-1.8%
	w. Big Bend Unit 4 SCR	8,232,257	8,232,074	183	0.0%
	x. Big Bend FGD System Reliability	1,566,595	1,587,494	(20,899)	-1.3%
	y. Clean Air Mercury Rule	151,020	110,652	40,368	36.5%
	z. SO_2 Emissions Allowances	(5,037)	(1,669)	(3,368)	-201.8%
2.	Total Investment Projects - Recoverable Costs	$42,234,385	$46,218,193	($3,983,808)	-8.6%
3.	Recoverable Costs Allocated to Energy	$42,074,966	$46,058,825	($3,983,859)	-8.6%
4.	Recoverable Costs Allocated to Demand	$159,419	$159,368	$51	0.0%

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-08-0775-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 2009 to December 2009

Form 42-7E

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	$66,346	$66,193	$66,040	$65,887	$65,759	$65,812	$65,459	$65,305	$65,152	$64,998	$64,846	$64,692	$786,289		$786,289
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	37,440	37,310	37,180	37,050	36,931	36,804	36,674	36,544	36,414	36,284	36,153	36,024	440,808		440,808
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,796	6,781	6,767	6,752	6,740	6,726	6,712	6,697	6,682	6,667	6,653	6,638	80,611		80,611
	d.	Big Bend Fuel Oil Tank #1 Upgrade	4,604	4,593	4,583	4,572	4,564	4,554	4,543	4,534	4,523	4,512	4,502	4,491	54,575	$ 54,575	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,573	7,555	7,538	7,521	7,508	7,490	7,474	7,456	7,439	7,422	7,404	7,387	89,767	89,767	
	f.	Phillips Upgrade Tank #1 for FDEP	497	495	493	491	491	489	488	486	485	484	482	481	5,862	5,862	
	g.	Phillips Upgrade Tank #4 for FDEP	780	778	775	773	772	769	767	765	762	760	758	756	9,215	9,215	
	h.	Big Bend Unit 1 Classifier Replacement	11,759	11,725	11,689	11,654	11,623	11,589	11,554	11,519	11,483	11,448	11,413	11,379	138,835		138,835
	i.	Big Bend Unit 2 Classifier Replacement	8,510	8,485	8,461	8,436	8,415	8,390	8,365	8,341	8,316	8,291	8,266	8,242	100,518		100,518
	j.	Big Bend Section 114 Mercury Testing Platform	1,142	1,140	1,138	1,137	1,136	1,133	1,131	1,129	1,127	1,126	1,123	1,122	13,584		13,584
	k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	750,756	749,929	748,929	747,696	746,208	744,372	742,781	741,002	739,140	737,340	736,225	736,759	8,921,117		8,921,117
	l.	Big Bend FGD Optimization and Utilization	213,260	212,856	212,452	212,048	211,731	211,348	210,943	210,539	210,135	209,731	209,326	208,921	2,533,290		2,533,290
	m.	Big Bend NO_x Emissions Reduction	66,999	66,927	66,854	66,780	66,737	66,667	66,589	66,523	66,459	66,720	67,335	67,563	802,153		802,153
	n.	Big Bend PM Minimization and Monitoring	89,786	90,356	90,910	90,901	90,897	90,769	90,734	90,715	90,551	90,349	90,146	89,943	1,086,037		1,086,037
	o.	Polk NO_x Emissions Reduction	17,046	17,001	16,959	16,915	16,879	16,837	16,794	16,752	16,709	16,666	16,623	16,579	201,759		201,759
	p.	Big Bend Unit 4 SOFA	27,352	27,302	27,253	27,203	27,165	27,118	27,068	27,018	26,969	26,919	26,870	26,820	325,057		325,057
	q.	Big Bend Unit 1 Pre-SCR	23,049	23,005	22,961	22,917	22,883	22,840	22,796	22,753	22,709	22,665	22,621	22,577	273,776		273,776
	r.	Big Bend Unit 2 Pre-SCR	18,485	18,445	18,406	18,365	18,332	18,295	18,256	18,216	18,176	18,137	18,097	18,057	219,267		219,267
	s.	Big Bend Unit 3 Pre-SCR	32,111	32,053	31,997	31,939	31,895	31,613	31,226	31,170	31,113	31,056	31,000	30,944	378,117		378,117
	t.	Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	u.	Big Bend Unit 2 SCR	0	0	0	0	0	0	0	460,859	1,108,527	1,106,876	1,104,598	1,103,358	4,884,018		4,884,018
	v.	Big Bend Unit 3 SCR	919,651	918,474	917,164	915,710	914,741	913,439	911,669	910,050	908,429	906,809	905,189	903,570	10,944,895		10,944,895
	w.	Big Bend Unit 4 SCR	692,320	691,133	689,945	688,758	687,860	686,742	685,554	684,365	683,177	681,989	680,801	679,613	8,232,257		8,232,257
	x.	Big Bend FGD System Reliability	131,893	131,463	131,251	131,042	130,888	130,885	130,470	130,253	130,037	129,821	129,604	129,388	1,566,595		1,566,595
	y.	Clean Air Mercury Rule	9,951	10,166	10,483	10,611	13,362	13,462	13,567	13,774	13,958	13,930	13,902	13,874	151,020		151,020
	z.	SO_2 Emissions Allowances (B)	(435)	(433)	(431)	(430)	(428)	(425)	(422)	(417)	(412)	(408)	(401)	(397)	(5,037)		(5,037)
2.		Total Investment Projects - Recoverable Costs	3,137,450	3,133,732	3,129,777	3,124,728	3,123,089	3,117,318	3,111,172	3,566,348	4,208,060	4,200,394	4,193,536	4,188,781	42,234,385	$ 159,419	$ 42,074,966
3.		Recoverable Costs Allocated to Energy	3,123,996	3,120,311	3,116,388	3,111,371	3,109,754	3,104,016	3,097,900	3,553,107	4,194,851	4,187,216	4,180,390	4,175,666	42,074,966		
4.		Recoverable Costs Allocated to Demand	13,454	13,421	13,389	13,357	13,335	13,302	13,272	13,241	13,209	13,178	13,146	13,115	159,419		
5.		Retail Energy Jurisdictional Factor	0.9891913	0.9892481	0.9926581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498			
6.		Retail Demand Jurisdictional Factor	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232			
7.		Jurisdictional Energy Recoverable Costs (C)	3,090,230	3,086,762	3,094,131	3,081,101	3,066,566	3,060,674	2,999,088	3,425,331	4,054,762	4,040,593	4,056,532	4,078,998	41,134,768		
8.		Jurisdictional Demand Recoverable Costs (D)	12,899	12,867	12,836	12,806	12,785	12,753	12,724	12,694	12,664	12,634	12,603	12,574	152,839		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$3,103,129	$3,099,629	$3,106,967	$3,093,907	$3,079,351	$3,073,427	$3,011,812	$3,438,025	$4,067,426	$4,053,227	$4,069,135	$4,091,572	$41,287,607		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8P, Line 9
(B) Project's Total Return Component on Form 42-8P, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

DOCKET NO. 090007-EI
ECRC 2009 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 2009 to December 2009

Form 42-8E
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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		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	(3,021,777)	(3,037,570)	(3,053,363)	(3,069,156)	(3,084,949)	(3,100,742)	(3,116,535)	(3,132,328)	(3,148,121)	(3,163,914)	(3,179,707)	(3,195,500)	(3,211,293)	
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)	$5,217,881	5,202,088	5,186,295	5,170,502	5,154,709	5,138,916	5,123,123	5,107,330	5,091,537	5,075,744	5,059,951	5,044,158	5,028,365	
6.	Average Net Investment		5,209,985	5,194,192	5,178,399	5,162,606	5,146,813	5,131,020	5,115,227	5,099,434	5,083,641	5,067,848	5,052,055	5,036,262	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		38,310	38,194	38,078	37,962	37,482	37,280	37,166	37,051	36,936	36,821	36,707	36,592	$448,579
	b. Debt Component Grossed Up For Taxes (F)		12,243	12,206	12,169	12,132	12,484	12,539	12,500	12,461	12,423	12,384	12,346	12,307	148,194
8.	Investment Expenses														
	a. Depreciation (C)		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)		66,346	66,193	66,040	65,887	65,759	65,612	65,459	65,305	65,152	64,998	64,846	64,692	786,289
	a. Recoverable Costs Allocated to Energy		66,346	66,193	66,040	65,887	65,759	65,612	65,459	65,305	65,152	64,998	64,846	64,692	786,289
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		65,629	65,481	65,568	65,246	64,846	64,696	63,371	62,957	62,976	62,722	62,925	63,194	769,611
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$65,629	$65,481	$65,568	$65,246	$64,846	$64,696	$63,371	$62,957	$62,976	$62,722	$62,925	$63,194	$769,611

Notes:

(A) Applicable depreciable base for Big Bend; account 312.45 ($8,239,658)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 2.3%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(2,534,402)	(2,547,811)	(2,561,220)	(2,574,629)	(2,588,038)	(2,601,447)	(2,614,856)	(2,628,265)	(2,641,674)	(2,655,083)	(2,668,492)	(2,681,901)	(2,695,310)	
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)	$2,483,332	2,469,923	2,456,514	2,443,105	2,429,696	2,416,287	2,402,878	2,389,469	2,376,060	2,362,651	2,349,242	2,335,833	2,322,424	
6.	Average Net Investment		2,476,628	2,463,219	2,449,810	2,436,401	2,422,992	2,409,583	2,396,174	2,382,765	2,369,356	2,355,947	2,342,538	2,329,129	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,211	18,112	18,014	17,915	17,645	17,507	17,410	17,312	17,215	17,118	17,020	16,923	$210,402
	b. Debt Component Grossed Up For Taxes (F)		5,820	5,789	5,757	5,726	5,877	5,888	5,855	5,823	5,790	5,757	5,724	5,692	69,498
8.	Investment Expenses														
	a. Depreciation (C)		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)		37,440	37,310	37,180	37,050	36,931	36,804	36,674	36,544	36,414	36,284	36,153	36,024	440,808
	a. Recoverable Costs Allocated to Energy		37,440	37,310	37,180	37,050	36,931	36,804	36,674	36,544	36,414	36,284	36,153	36,024	440,808
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		37,035	36,909	36,914	36,690	36,418	36,290	35,504	35,230	35,198	35,013	35,082	35,190	431,473
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$37,035	$36,909	$36,914	$36,690	$36,418	$36,290	$35,504	$35,230	$35,198	$35,013	$35,082	$35,190	$431,473

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009. Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of
(C) Applicable depreciation rates are 3.3% and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(321,269)	(322,785)	(324,301)	(325,817)	(327,333)	(328,849)	(330,365)	(331,881)	(333,397)	(334,913)	(336,429)	(337,945)	(339,461)	
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)	$544,942	543,426	541,910	540,394	538,878	537,362	535,846	534,330	532,814	531,298	529,782	528,266	526,750	
6.	Average Net Investment		544,184	542,668	541,152	539,636	538,120	536,604	535,088	533,572	532,056	530,540	529,024	527,508	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,001	3,990	3,979	3,968	3,919	3,899	3,888	3,877	3,866	3,855	3,844	3,833	$46,919
	b. Debt Component Grossed Up For Taxes (F)		1,279	1,275	1,272	1,268	1,305	1,311	1,308	1,304	1,300	1,296	1,293	1,289	15,500
8	Investment Expenses														
	a. Depreciation (C)		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)		6,796	6,781	6,767	6,752	6,740	6,726	6,712	6,697	6,682	6,667	6,653	6,638	80,611
	a. Recoverable Costs Allocated to Energy		6,796	6,781	6,767	6,752	6,740	6,726	6,712	6,697	6,682	6,667	6,653	6,638	80,611
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		6,723	6,708	6,719	6,686	6,646	6,632	6,498	6,456	6,459	6,434	6,456	6,484	78,901
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,723	$6,708	$6,719	$6,686	$6,646	$6,632	$6,498	$6,456	$6,459	$6,434	$6,456	$6,484	$78,901

Notes:

(A) Applicable depreciable base for Big Bend; account 315.44 ($866,211)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 2.1%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(133,624)	(134,702)	(135,780)	(136,858)	(137,936)	(139,014)	(140,092)	(141,170)	(142,248)	(143,326)	(144,404)	(145,482)	(146,560)	
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)	$363,954	362,876	361,798	360,720	359,642	358,564	357,486	356,408	355,330	354,252	353,174	352,096	351,018	
6.	Average Net Investment		363,415	362,337	361,259	360,181	359,103	358,025	356,947	355,869	354,791	353,713	352,635	351,557	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,672	2,664	2,656	2,648	2,615	2,601	2,593	2,586	2,578	2,570	2,562	2,554	$31,299
	b. Debt Component Grossed Up For Taxes (F)		854	851	849	846	871	875	872	870	867	864	862	859	10,340
8.	Investment Expenses														
	a. Depreciation (C)		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)		4,604	4,593	4,583	4,572	4,564	4,554	4,543	4,534	4,523	4,512	4,502	4,491	54,575
	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		4,604	4,593	4,583	4,572	4,564	4,554	4,543	4,534	4,523	4,512	4,502	4,491	54,575
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		4,414	4,403	4,394	4,383	4,376	4,366	4,355	4,347	4,336	4,326	4,316	4,306	52,322
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,414	$4,403	$4,394	$4,383	$4,376	$4,366	$4,355	$4,347	$4,336	$4,326	$4,316	$4,306	$52,322

Notes:

(A) Applicable depreciable base for Big Bend; account 312.40 ($497,578)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 2.6%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(219,796)	(221,569)	(223,342)	(225,115)	(226,888)	(228,661)	(230,434)	(232,207)	(233,980)	(235,753)	(237,526)	(239,299)	(241,072)	
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)	$598,605	596,832	595,059	593,286	591,513	589,740	587,967	586,194	584,421	582,648	580,875	579,102	577,329	
6.	Average Net Investment		597,719	595,946	594,173	592,400	590,627	588,854	587,081	585,308	583,535	581,762	579,989	578,216	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,395	4,382	4,369	4,356	4,302	4,278	4,266	4,253	4,240	4,227	4,214	4,201	$51,483
	b. Debt Component Grossed Up For Taxes (F)		1,405	1,400	1,396	1,392	1,433	1,439	1,435	1,430	1,426	1,422	1,417	1,413	17,008
8.	Investment Expenses														
	a. Depreciation (C)		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)		7,573	7,555	7,538	7,521	7,508	7,490	7,474	7,456	7,439	7,422	7,404	7,387	89,767
	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		7,573	7,555	7,538	7,521	7,508	7,490	7,474	7,456	7,439	7,422	7,404	7,387	89,767
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		7,260	7,243	7,227	7,211	7,198	7,181	7,165	7,148	7,132	7,116	7,098	7,082	86,061
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,260	$7,243	$7,227	$7,211	$7,198	$7,181	$7,165	$7,148	$7,132	$7,116	$7,098	$7,082	$86,061

Notes:

(A) Applicable depreciable base for Big Bend; account 312.40 ($818,401)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		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	(20,820)	(20,963)	(21,106)	(21,249)	(21,392)	(21,535)	(21,678)	(21,821)	(21,964)	(22,107)	(22,250)	(22,393)	(22,536)	
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)	$36,457	36,314	36,171	36,028	35,885	35,742	35,599	35,456	35,313	35,170	35,027	34,884	34,741	
6.	Average Net Investment		36,386	36,243	36,100	35,957	35,814	35,671	35,528	35,385	35,242	35,099	34,956	34,813	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		268	267	265	264	261	259	258	257	256	255	254	253	$3,117
	b. Debt Component Grossed Up For Taxes (F)		86	85	85	84	87	87	87	86	86	86	85	85	1,029
8.	Investment Expenses														
	a. Depreciation (C)		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)		497	495	493	491	491	489	488	486	485	484	482	481	5,862
	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		497	495	493	491	491	489	488	486	485	484	482	481	5,862
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		476	475	473	471	471	469	468	466	465	464	462	461	5,621
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$476	$475	$473	$471	$471	$469	$468	$466	$465	$464	$462	$461	$5,621

Notes:

(A) Applicable depreciable base for Phillips; account 342.28 ($57,277)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 3.0%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	
	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	(33,299)	(33,525)	(33,751)	(33,977)	(34,203)	(34,429)	(34,655)	(34,881)	(35,107)	(35,333)	(35,559)	(35,785)	(36,011)	
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)	$57,173	56,947	56,721	56,495	56,269	56,043	55,817	55,591	55,365	55,139	54,913	54,687	54,461	
6.	Average Net Investment		57,060	56,834	56,608	56,382	56,156	55,930	55,704	55,478	55,252	55,026	54,800	54,574	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		420	418	416	415	409	406	405	403	401	400	398	397	$4,888
	b. Debt Component Grossed Up For Taxes (F)		134	134	133	132	137	137	136	136	135	134	134	133	1,615
8.	Investment Expenses														
	a. Depreciation (C)		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)		780	778	775	773	772	769	767	765	762	760	758	756	9,215
	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		780	778	775	773	772	769	767	765	762	760	758	756	9,215
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		748	746	743	741	740	737	735	733	731	729	727	725	8,835
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$748	$746	$743	$741	$740	$737	$735	$733	$731	$729	$727	$725	$8,835

Notes:

(A) Applicable depreciable base for Phillips; account 342.28 ($90,472)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 3.0%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(475,592)	(479,212)	(482,832)	(486,452)	(490,072)	(493,692)	(497,312)	(500,932)	(504,552)	(508,172)	(511,792)	(515,412)	(519,032)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$840,665	837,045	833,425	829,805	826,185	822,565	818,945	815,325	811,705	808,085	804,465	800,845	797,225	
6.	Average Net Investment		838,855	835,235	831,615	827,995	824,375	820,755	817,135	813,515	809,895	806,275	802,655	799,035	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,168	6,142	6,115	6,088	6,003	5,963	5,937	5,911	5,884	5,858	5,832	5,806	$71,707
	b. Debt Component Grossed Up For Taxes (F)		1,971	1,963	1,954	1,946	2,000	2,006	1,997	1,988	1,979	1,970	1,961	1,953	23,688
8.	Investment Expenses														
	a. Depreciation (C)		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)		11,759	11,725	11,689	11,654	11,623	11,589	11,554	11,519	11,483	11,448	11,413	11,379	138,835
	a. Recoverable Costs Allocated to Energy		11,759	11,725	11,689	11,654	11,623	11,589	11,554	11,519	11,483	11,448	11,413	11,379	138,835
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		11,632	11,599	11,606	11,541	11,462	11,427	11,185	11,105	11,100	11,047	11,075	11,116	135,895
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,632	$11,599	$11,606	$11,541	$11,462	$11,427	$11,185	$11,105	$11,100	$11,047	$11,075	$11,116	$135,895

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 ($1,316,257)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax ra 38.575% (expansion factor of 1.63490).

(C) Applicable depreciation rate is 3.3%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 8 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(368,694)	(371,238)	(373,782)	(376,326)	(378,870)	(381,414)	(383,958)	(386,502)	(389,046)	(391,590)	(394,134)	(396,678)	(399,222)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$616,100	613,556	611,012	608,468	605,924	603,380	600,836	598,292	595,748	593,204	590,660	588,116	585,572	
6.	Average Net Investment		614,828	612,284	609,740	607,196	604,652	602,108	599,564	597,020	594,476	591,932	589,388	586,844	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,521	4,502	4,484	4,465	4,404	4,375	4,356	4,338	4,319	4,301	4,282	4,264	$52,611
	b. Debt Component Grossed Up For Taxes (F)		1,445	1,439	1,433	1,427	1,467	1,471	1,465	1,459	1,453	1,446	1,440	1,434	17,379
8.	Investment Expenses														
	a. Depreciation (C)		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)		8,510	8,485	8,461	8,436	8,415	8,390	8,365	8,341	8,316	8,291	8,266	8,242	100,518
	a. Recoverable Costs Allocated to Energy		8,510	8,485	8,461	8,436	8,415	8,390	8,365	8,341	8,316	8,291	8,266	8,242	100,518
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		8,418	8,394	8,401	8,354	8,298	8,273	8,098	8,041	8,038	8,001	8,021	8,051	98,388
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,418	$8,394	$8,401	$8,354	$8,298	$8,273	$8,098	$8,041	$8,038	$8,001	$8,021	$8,051	$98,388

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 ($984,794)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 3.1%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(23,647)	(23,848)	(24,049)	(24,250)	(24,451)	(24,652)	(24,853)	(25,054)	(25,255)	(25,456)	(25,657)	(25,858)	(26,059)	
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)	$97,090	96,889	96,688	96,487	96,286	96,085	95,884	95,683	95,482	95,281	95,080	94,879	94,678	
6.	Average Net Investment		96,990	96,789	96,588	96,387	96,186	95,985	95,784	95,583	95,382	95,181	94,980	94,779	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		713	712	710	709	701	697	696	694	693	692	690	689	$8,396
	b. Debt Component Grossed Up For Taxes (F)		228	227	227	227	234	235	234	234	233	233	232	232	2,776
8.	Investment Expenses														
	a. Depreciation (C)		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)		1,142	1,140	1,138	1,137	1,136	1,133	1,131	1,129	1,127	1,126	1,123	1,122	13,584
	a. Recoverable Costs Allocated to Energy		1,142	1,140	1,138	1,137	1,136	1,133	1,131	1,129	1,127	1,126	1,123	1,122	13,584
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		1,130	1,128	1,130	1,126	1,120	1,117	1,095	1,088	1,089	1,087	1,090	1,096	13,296
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,130	$1,128	$1,130	$1,126	$1,120	$1,117	$1,095	$1,088	$1,089	$1,087	$1,090	$1,096	$13,296

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40 ($120,737)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).
(C) Applicable depreciation rate is 2.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		($7,385)	$75,444	$114,696	$33,429	$4,403	$6,944	$24,655	$8,592	$13,992	$21,129	$155,549	$360,416	$811,862
	b. Clearings to Plant		333,163	18,963	6,294	7,671	4,511	85,729	20,497	463	0	0	0	0	477,291
	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)	$83,555,351	$83,888,514	$83,907,477	$83,913,771	$83,921,442	$83,925,953	$84,011,682	$84,032,179	$84,032,642	$84,032,642	$84,032,642	$84,032,642	$84,032,642	
3.	Less: Accumulated Depreciation	(29,343,956)	(29,545,881)	(29,748,612)	(29,951,388)	(30,154,180)	(30,356,990)	(30,559,811)	(30,762,839)	(30,965,917)	(31,168,996)	(31,372,075)	(31,575,154)	(31,778,233)	
4.	CWIP - Non-Interest Bearing	2,455,300	2,114,752	2,171,232	2,279,634	2,305,392	2,305,284	2,226,499	2,230,657	2,238,786	2,252,778	2,273,907	2,429,455	2,789,871	
5.	Net Investment (Lines 2 + 3 + 4)	$56,666,695	56,457,384	56,330,097	56,242,017	56,072,654	55,874,247	55,678,370	55,499,997	55,305,510	55,116,424	54,934,473	54,886,943	55,044,280	
6.	Average Net Investment		56,562,039	56,393,741	56,286,057	56,157,335	55,973,450	55,776,308	55,589,183	55,402,753	55,210,967	55,025,448	54,910,708	54,965,611	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		415,910	414,673	413,881	412,934	407,632	405,252	403,892	402,538	401,144	399,797	398,963	399,362	$4,875,978
	b. Debt Component Grossed Up For Taxes (F)		132,921	132,525	132,272	131,970	135,766	136,299	135,841	135,386	134,917	134,464	134,183	134,318	1,610,862
8.	Investment Expenses														
	a. Depreciation (C)		201,925	202,731	202,776	202,792	202,810	202,821	203,028	203,078	203,079	203,079	203,079	203,079	2,434,277
	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)		750,756	749,929	748,929	747,696	746,208	744,372	742,761	741,002	739,140	737,340	736,225	736,759	8,921,117
	a. Recoverable Costs Allocated to Energy		750,756	749,929	748,929	747,696	746,208	744,372	742,761	741,002	739,140	737,340	736,225	736,759	8,921,117
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666048	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		742,641	741,866	743,580	740,422	735,845	733,978	719,070	714,354	714,456	711,521	714,412	719,703	8,731,848
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$742,641	$741,866	$743,580	$740,422	$735,845	$733,978	$719,070	$714,354	$714,456	$711,521	$714,412	$719,703	$8,731,848

Notes:

(A) Applicable depreciable base for Big Bend; account 312.46 ($84,032,642)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rates are 2.9% .

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(4,032,085)	(4,073,727)	(4,115,369)	(4,157,011)	(4,198,653)	(4,240,295)	(4,281,937)	(4,323,579)	(4,365,221)	(4,406,863)	(4,448,505)	(4,490,147)	(4,531,789)	
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)	$17,707,652	17,666,010	17,624,368	17,582,726	17,541,084	17,499,442	17,457,800	17,416,158	17,374,516	17,332,874	17,291,232	17,249,590	17,207,948	
6.	Average Net Investment		17,686,831	17,645,189	17,603,547	17,561,905	17,520,263	17,478,621	17,436,979	17,395,337	17,353,695	17,312,053	17,270,411	17,228,769	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		130,054	129,748	129,442	129,136	127,593	126,994	126,691	126,389	126,086	125,784	125,481	125,178	$1,528,576
	b. Debt Component Grossed Up For Taxes (F)		41,564	41,466	41,368	41,270	42,496	42,712	42,610	42,508	42,407	42,305	42,203	42,101	505,010
8.	Investment Expenses														
	a. Depreciation (C)		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)		213,260	212,856	212,452	212,048	211,731	211,348	210,943	210,539	210,135	209,731	209,326	208,921	2,533,290
	a. Recoverable Costs Allocated to Energy		213,260	212,856	212,452	212,048	211,731	211,348	210,943	210,539	210,135	209,731	209,326	208,921	2,533,290
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		210,955	210,567	210,935	209,985	208,790	208,397	204,215	202,968	203,117	202,387	203,124	204,084	2,479,524
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$210,955	$210,567	$210,935	$209,985	$208,790	$208,397	$204,215	$202,968	$203,117	$202,387	$203,124	$204,084	$2,479,524

Notes:

(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45($21,699,919)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).
(C) Applicable depreciation rates are 1.5% and 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$727	$1,294	$711	$666	$1,402	($358)	$1,610	$1,610	$1,711	$68,662	$44,841	$0	$122,876
	b. Clearings to Plant		727	1,294	711	666	1,402	(358)	1,610	1,610	1,711	68,662	44,841	0	122,876
	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)	$3,338,427	$3,339,154	$3,340,448	$3,341,159	$3,341,825	$3,343,227	$3,342,869	$3,344,479	$3,346,089	$3,347,800	$3,416,462	$3,461,303	$3,461,303	
3.	Less: Accumulated Depreciation	2,678,047	2,669,388	2,660,727	2,652,064	2,643,399	2,634,733	2,626,064	2,617,395	2,608,723	2,600,047	2,591,368	2,582,540	2,573,615	
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)	$6,016,474	6,008,542	6,001,175	5,993,223	5,985,224	5,977,960	5,968,933	5,961,874	5,954,812	5,947,847	6,007,830	6,043,843	6,034,918	
6.	Average Net Investment		6,012,508	6,004,859	5,997,199	5,989,224	5,981,592	5,973,447	5,965,404	5,958,343	5,951,330	5,977,839	6,025,837	6,039,381	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		44,211	44,155	44,098	44,040	43,562	43,401	43,343	43,291	43,240	43,433	43,782	43,880	$524,436
	b. Debt Component Grossed Up For Taxes (F)		14,129	14,111	14,093	14,075	14,509	14,597	14,577	14,560	14,543	14,608	14,725	14,758	173,285
8.	Investment Expenses														
	a. Depreciation (C)		8,659	8,661	8,663	8,665	8,666	8,669	8,669	8,672	8,676	8,679	8,828	8,925	104,432
	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)		66,999	66,927	66,854	66,780	66,737	66,667	66,589	66,523	66,459	66,720	67,335	67,563	802,153
	a. Recoverable Costs Allocated to Energy		66,999	66,927	66,854	66,780	66,737	66,667	66,589	66,523	66,459	66,720	67,335	67,563	802,153
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		66,275	66,207	66,377	66,130	65,810	65,736	64,465	64,131	64,240	64,384	65,340	65,999	785,094
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,275	$66,207	$66,377	$66,130	$65,810	$65,736	$64,465	$64,131	$64,240	$64,384	$65,340	$65,999	$785,094

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($710,414)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).
(C) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$129,332	$32,623	$13,401	$20,374	$3,993	$7,958	$22,836	$5,440	$0	$0	$0	$0	$235,957
	b. Clearings to Plant		0	254,582	13,401	20,374	3,993	7,958	22,836	5,440	0	0	0	0	328,584
	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)	$7,991,052	$7,991,052	$8,245,634	$8,259,035	$8,279,409	$8,283,402	$8,291,360	$8,314,196	$8,319,636	$8,319,636	$8,319,636	$8,319,636	$8,319,636	
3.	Less: Accumulated Depreciation	(968,319)	(988,514)	(1,008,709)	(1,029,434)	(1,050,187)	(1,070,983)	(1,091,787)	(1,112,608)	(1,133,476)	(1,154,356)	(1,175,236)	(1,196,116)	(1,216,996)	
4.	CWIP - Non-Interest Bearing	92,627	221,959	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,115,360	7,224,497	7,236,925	7,229,601	7,229,222	7,212,419	7,199,573	7,201,588	7,186,160	7,165,280	7,144,400	7,123,520	7,102,640	
6.	Average Net Investment		7,169,929	7,230,711	7,233,263	7,229,412	7,220,821	7,205,996	7,200,581	7,193,874	7,175,720	7,154,840	7,133,960	7,113,080	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		52,722	53,169	53,187	53,159	52,587	52,356	52,317	52,268	52,136	51,985	51,833	51,681	$629,400
	b. Debt Component Grossed Up For Taxes (F)		16,849	16,992	16,998	16,989	17,514	17,609	17,596	17,579	17,535	17,484	17,433	17,382	207,960
8.	Investment Expenses														
	a. Depreciation (C)		20,195	20,195	20,725	20,753	20,796	20,804	20,821	20,868	20,880	20,880	20,880	20,880	248,677
	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)		89,766	90,356	90,910	90,901	90,897	90,769	90,734	90,715	90,551	90,349	90,146	89,943	1,086,037
	a. Recoverable Costs Allocated to Energy		89,766	90,356	90,910	90,901	90,897	90,769	90,734	90,715	90,551	90,349	90,146	89,943	1,086,037
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		88,796	89,385	90,261	90,017	89,635	89,502	87,840	87,453	87,527	87,185	87,475	87,861	1,062,937
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$88,796	$89,385	$90,261	$90,017	$89,635	$89,502	$87,840	$87,453	$87,527	$87,185	$87,475	$87,861	$1,062,937

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), 315.43 ($328,584), and 315.44 ($351,594)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, 2.5%, and 2.1%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(258,618)	(263,042)	(267,466)	(271,890)	(276,314)	(280,738)	(285,162)	(289,586)	(294,010)	(298,434)	(302,858)	(307,282)	(311,706)	
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)	$1,302,855	1,298,431	1,294,007	1,289,583	1,285,159	1,280,735	1,276,311	1,271,887	1,267,463	1,263,039	1,258,615	1,254,191	1,249,767	
6.	Average Net Investment		1,300,643	1,296,219	1,291,795	1,287,371	1,282,947	1,278,523	1,274,099	1,269,675	1,265,251	1,260,827	1,256,403	1,251,979	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,564	9,531	9,499	9,466	9,343	9,289	9,257	9,225	9,193	9,161	9,129	9,096	$111,753
	b. Debt Component Grossed Up For Taxes (F)		3,057	3,046	3,036	3,025	3,112	3,124	3,113	3,103	3,092	3,081	3,070	3,059	36,918
8.	Investment Expenses														
	a. Depreciation (C)		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)		17,045	17,001	16,959	16,915	16,879	16,837	16,794	16,752	16,709	16,666	16,623	16,579	201,759
	a. Recoverable Costs Allocated to Energy		17,045	17,001	16,959	16,915	16,879	16,837	16,794	16,752	16,709	16,666	16,623	16,579	201,759
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		16,861	16,818	16,838	16,750	16,645	16,602	16,258	16,150	16,151	16,082	16,130	16,195	197,480
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,861	$16,818	$16,838	$16,750	$16,645	$16,602	$16,258	$16,150	$16,151	$16,082	$16,130	$16,195	$197,480

Notes:
(A) Applicable depreciable base for Polk; account 342.81 ($1,561,473)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(264,638)	(269,755)	(274,872)	(279,989)	(285,106)	(290,223)	(295,340)	(300,457)	(305,574)	(310,691)	(315,808)	(320,925)	(326,042)	
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)	$2,294,092	2,288,975	2,283,858	2,278,741	2,273,624	2,268,507	2,263,390	2,258,273	2,253,156	2,248,039	2,242,922	2,237,805	2,232,688	
6.	Average Net Investment		2,291,534	2,286,417	2,281,300	2,276,183	2,271,066	2,265,949	2,260,832	2,255,715	2,250,598	2,245,481	2,240,364	2,235,247	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		16,850	16,812	16,775	16,737	16,539	16,464	16,426	16,389	16,352	16,315	16,278	16,241	$198,178
	b. Debt Component Grossed Up For Taxes (F)		5,385	5,373	5,361	5,349	5,509	5,537	5,525	5,512	5,500	5,487	5,475	5,462	65,475
8.	Investment Expenses														
	a. Depreciation (C)		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)		27,352	27,302	27,253	27,203	27,165	27,118	27,068	27,018	26,969	26,919	26,870	26,820	325,057
	a. Recoverable Costs Allocated to Energy		27,352	27,302	27,253	27,203	27,165	27,118	27,068	27,018	26,969	26,919	26,870	26,820	325,057
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		27,056	27,008	27,058	26,938	26,788	26,739	26,205	26,046	26,068	25,976	26,074	26,199	318,155
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$27,056	$27,008	$27,058	$26,938	$26,788	$26,739	$26,205	$26,046	$26,068	$25,976	$26,074	$26,199	$318,155

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($2,558,730)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate o 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(106,585)	(111,120)	(115,655)	(120,190)	(124,725)	(129,260)	(133,795)	(138,330)	(142,865)	(147,400)	(151,935)	(156,470)	(161,005)	
4.	CWIP - Non-Interest Bearing	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	
5.	Net Investment (Lines 2 + 3 + 4)	$1,910,303	1,905,768	1,901,233	1,896,698	1,892,163	1,887,628	1,883,093	1,878,558	1,874,023	1,869,488	1,864,953	1,860,418	1,855,883	
6.	Average Net Investment		1,908,036	1,903,501	1,898,966	1,894,431	1,889,896	1,885,361	1,880,826	1,876,291	1,871,756	1,867,221	1,862,686	1,858,151	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,030	13,997	13,963	13,930	13,764	13,698	13,665	13,633	13,600	13,567	13,534	13,501	$164,882
	b. Debt Component Grossed Up For Taxes (F)		4,484	4,473	4,463	4,452	4,584	4,607	4,596	4,585	4,574	4,563	4,552	4,541	54,474
8.	Investment Expenses														
	a. Depreciation (C)		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)		23,049	23,005	22,961	22,917	22,883	22,840	22,796	22,753	22,709	22,665	22,621	22,577	273,776
	a. Recoverable Costs Allocated to Energy		23,049	23,005	22,961	22,917	22,883	22,840	22,796	22,753	22,709	22,665	22,621	22,577	273,776
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		22,800	22,758	22,797	22,694	22,565	22,521	22,069	21,935	21,951	21,871	21,951	22,054	267,966
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$22,800	$22,758	$22,797	$22,694	$22,565	$22,521	$22,069	$21,935	$21,951	$21,871	$21,951	$22,054	$267,966

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 ($1,649,121)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(96,044)	(100,131)	(104,218)	(108,305)	(112,392)	(116,479)	(120,566)	(124,653)	(128,740)	(132,827)	(136,914)	(141,001)	(145,088)	
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)	$1,485,843	1,481,756	1,477,669	1,473,582	1,469,495	1,465,408	1,461,321	1,457,234	1,453,147	1,449,060	1,444,973	1,440,886	1,436,799	
6.	Average Net Investment		1,483,800	1,479,713	1,475,626	1,471,539	1,467,452	1,463,365	1,459,278	1,455,191	1,451,104	1,447,017	1,442,930	1,438,843	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,911	10,881	10,851	10,820	10,686	10,632	10,603	10,573	10,543	10,514	10,484	10,454	$127,952
	b. Debt Component Grossed Up For Taxes (F)		3,487	3,477	3,468	3,458	3,559	3,576	3,566	3,556	3,546	3,536	3,526	3,516	42,271
8.	Investment Expenses														
	a. Depreciation (C)		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)		18,485	18,445	18,406	18,365	18,332	18,295	18,256	18,216	18,176	18,137	18,097	18,057	219,267
	a. Recoverable Costs Allocated to Energy		18,485	18,445	18,406	18,365	18,332	18,295	18,256	18,216	18,176	18,137	18,097	18,057	219,267
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		18,285	18,247	18,275	18,186	18,077	18,040	17,674	17,561	17,569	17,502	17,561	17,639	214,616
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,285	$18,247	$18,275	$18,186	$18,077	$18,040	$17,674	$17,561	$17,569	$17,502	$17,561	$17,639	$214,616

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 ($1,581,887)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 3.1%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	($47,000)	$0	$0	$0	$0	$0	$0	($47,000)
	b. Clearings to Plant		0	0	0	0	0	(47,000)	0	0	0	0	0	0	(47,000)
	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)	$2,753,507	$2,753,507	$2,753,507	$2,753,507	$2,753,507	$2,753,507	$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	(49,994)	(55,901)	(61,808)	(67,715)	(73,622)	(79,529)	(85,436)	(91,241)	(97,046)	(102,851)	(108,656)	(114,461)	(120,266)	
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)	$2,703,513	2,697,606	2,691,699	2,685,792	2,679,885	2,673,978	2,621,071	2,615,266	2,609,461	2,603,656	2,597,851	2,592,046	2,586,241	
6.	Average Net Investment		2,700,560	2,694,653	2,688,746	2,682,839	2,676,932	2,647,525	2,618,169	2,612,364	2,606,559	2,600,754	2,594,949	2,589,144	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		19,858	19,814	19,771	19,727	19,495	19,236	19,023	18,981	18,938	18,896	18,854	18,812	$231,405
	b. Debt Component Grossed Up For Taxes (F)		6,346	6,332	6,319	6,305	6,493	6,470	6,398	6,384	6,370	6,355	6,341	6,327	76,440
8.	Investment Expenses														
	a. Depreciation (C)		5,907	5,907	5,907	5,907	5,907	5,907	5,805	5,805	5,805	5,805	5,805	5,805	70,272
	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)		32,111	32,053	31,997	31,939	31,895	31,613	31,226	31,170	31,113	31,056	31,000	30,944	378,117
	a. Recoverable Costs Allocated to Energy		32,111	32,053	31,997	31,939	31,895	31,613	31,226	31,170	31,113	31,056	31,000	30,944	378,117
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		31,764	31,708	31,768	31,628	31,452	31,172	30,230	30,049	30,074	29,969	30,082	30,228	370,124
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$31,764	$31,708	$31,768	$31,628	$31,452	$31,172	$30,230	$30,049	$30,074	$29,969	$30,082	$30,228	$370,124

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).
(C) Applicable depreciation rate is 2.6% and 2.5%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$3,164,658	$564,360	$2,860,388	$1,932,745	$3,079,556	$1,977,509	$1,980,544	$2,941,495	$3,308,763	$3,709,737	$6,111,522	$4,931,795	$36,563,073
	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)	$35,640,098	$38,804,756	$39,369,116	$42,229,504	$44,162,249	$47,241,805	$49,219,314	$51,199,858	$54,141,353	$57,450,117	$61,159,854	$67,271,376	$72,203,171	
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)	$35,640,098	38,804,756	39,369,116	42,229,504	44,162,249	47,241,805	49,219,314	51,199,858	54,141,353	57,450,117	61,159,854	67,271,376	72,203,171	
6.	Average Net Investment		37,222,427	39,086,936	40,799,310	43,195,877	45,702,027	48,230,560	50,209,586	52,670,606	55,795,735	59,304,985	64,215,615	69,737,273	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component Grossed Up For Taxes (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	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		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)		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		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate are 3.3% and 2.5%.

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

(G) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$4,910,215	$3,666,316	$2,677,990	$768,539	$311,390	$187,267	$171,910	$68,900	$43,324	$18,593	$10,138	$195,510	$13,030,092
	b. Clearings to Plant		0	0	0	0	0	0	0	90,252,938	43,324	18,593	10,138	195,510	$90,520,503
	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)	$70,163,346	$75,073,561	$78,739,877	$81,417,867	$82,186,406	$82,497,796	$82,685,063	$82,856,973	$90,252,938	$90,296,262	$90,314,855	$90,324,993	$90,520,503	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(233,153)	(466,418)	(699,731)	(933,071)	
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)	$70,163,346	75,073,561	78,739,877	81,417,867	82,186,406	82,497,796	82,685,063	82,856,973	90,252,938	90,063,109	89,848,437	89,625,262	89,587,432	
6.	Average Net Investment		72,618,454	76,906,719	80,078,872	81,802,137	82,342,101	82,591,430	82,771,018	86,554,956	90,158,024	89,955,773	89,736,850	89,606,347	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	344,869	655,058	653,589	651,998	651,050	$2,956,564
	b. Debt Component Grossed Up For Taxes (G)		0	0	0	0	0	0	0	115,990	220,316	219,822	219,287	218,968	994,383
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	233,153	233,265	233,313	233,340	933,071
	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)		0	0	0	0	0	0	0	460,859	1,108,527	1,106,676	1,104,598	1,103,358	4,884,018
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	460,859	1,108,527	1,106,676	1,104,598	1,103,358	4,884,018
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860387	0.9861036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	444,286	1,071,507	1,067,924	1,071,871	1,077,815	4,733,403
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$444,286	$1,071,507	$1,067,924	$1,071,871	$1,077,815	$4,733,403

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 ($90,520,503)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 3.1%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

(G) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$41,648	$30,361	$19,412	$5,714	$46,762	($21,292)	$0	$0	$0	$0	$0	$0	$122,605
	b. Clearings to Plant		41,648	30,361	19,412	5,714	46,762	(21,292)	0	0	0	0	0	0	122,605
	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)	$78,586,604	$78,628,252	$78,658,613	$78,678,025	$78,683,739	$78,730,501	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	
3.	Less: Accumulated Depreciation	(913,440)	(1,080,022)	(1,246,694)	(1,413,432)	(1,580,212)	(1,747,004)	(1,913,898)	(2,080,746)	(2,247,594)	(2,414,442)	(2,581,290)	(2,748,138)	(2,914,986)	
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)	$77,673,164	77,548,230	77,411,919	77,264,593	77,103,527	76,983,497	76,795,311	76,628,463	76,461,615	76,294,767	76,127,919	75,961,071	75,794,223	
6.	Average Net Investment		77,610,697	77,480,075	77,338,256	77,184,060	77,043,512	76,889,404	76,711,887	76,545,039	76,378,191	76,211,343	76,044,495	75,877,647	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		570,684	569,724	568,681	567,547	561,077	558,653	557,363	556,151	554,938	553,726	552,514	551,302	$6,722,360
	b. Debt Component Grossed Up For Taxes (E)		182,385	182,078	181,745	181,383	186,872	187,892	187,458	187,051	186,643	186,235	185,827	185,420	2,220,989
8.	Investment Expenses														
	a. Depreciation (C)		166,582	166,672	166,738	166,780	166,792	166,894	166,848	166,848	166,848	166,848	166,848	166,848	2,001,546
	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)		919,651	918,474	917,164	915,710	914,741	913,439	911,669	910,050	908,429	906,809	905,189	903,570	10,944,895
	a. Recoverable Costs Allocated to Energy		919,651	918,474	917,164	915,710	914,741	913,439	911,669	910,050	908,429	906,809	905,189	903,570	10,944,895
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		909,711	908,599	910,614	908,801	902,037	900,684	882,590	877,323	878,092	875,055	878,370	882,652	10,712,528
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$909,711	$908,599	$910,614	$908,801	$902,037	$900,684	$882,590	$877,323	$878,092	$875,055	$878,370	$882,652	$10,712,528

Notes:

(A) Applicable depreciable base for Big Bend; account 311.43 ($3,162,013) and 312.43 ($75,547,196)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor
(C) Applicable depreciation rates are 1.2% and 2.6%
(D) Line 9a x Line 10
(E) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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ECRC 2008 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 2009 to December 2009

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	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)	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	
3.	Less: Accumulated Depreciation	(2,383,285)	(2,505,652)	(2,628,019)	(2,750,386)	(2,872,753)	(2,995,120)	(3,117,487)	(3,239,854)	(3,362,221)	(3,484,588)	(3,606,955)	(3,729,322)	(3,851,689)	
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)	$58,800,052	58,677,685	58,555,318	58,432,951	58,310,584	58,188,217	58,065,850	57,943,483	57,821,116	57,698,749	57,576,382	57,454,015	57,331,648	
6.	Average Net Investment		58,738,869	58,616,502	58,494,135	58,371,768	58,249,401	58,127,034	58,004,667	57,882,300	57,759,933	57,637,566	57,515,199	57,392,832	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		431,917	431,017	430,117	429,217	424,207	422,332	421,443	420,553	419,664	418,775	417,886	416,997	$5,084,125
	b. Debt Component Grossed Up For Taxes (F)		138,036	137,749	137,461	137,174	141,286	142,043	141,744	141,445	141,146	140,847	140,548	140,249	1,679,728
8.	Investment Expenses														
	a. Depreciation (C)		122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	1,468,404
	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)		692,320	691,133	689,945	688,758	687,860	686,742	685,554	684,365	683,177	681,989	680,801	679,613	8,232,257
	a. Recoverable Costs Allocated to Energy		692,320	691,133	689,945	688,758	687,860	686,742	685,554	684,365	683,177	681,989	680,801	679,613	8,232,257
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		684,837	683,702	685,017	682,057	678,307	677,153	663,687	659,754	660,362	658,108	660,630	663,880	8,057,494
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$684,837	$683,702	$685,017	$682,057	$678,307	$677,153	$663,687	$659,754	$660,362	$658,108	$660,630	$663,880	$8,057,494

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($61,183,337)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 2.4%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		($2,053)	$0	$841	$641	$135	$104	$0	$0	$0	$0	$0	$0	($332)
	b. Clearings to Plant		(2,053)	0	841	641	135	104	0	0	0	0	0	0	(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 (A)	$11,564,783	$11,562,730	$11,562,730	$11,563,571	$11,564,212	$11,564,347	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	
3.	Less: Accumulated Depreciation	(293,528)	(315,815)	(338,098)	(360,381)	(382,665)	(404,951)	(427,237)	(449,523)	(471,809)	(494,095)	(516,381)	(538,667)	(560,953)	
4.	CWIP - Non-Interest Bearing	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	
5.	Net Investment (Lines 2 + 3 + 4)	$11,287,438	11,263,098	11,240,815	11,219,373	11,197,730	11,175,579	11,153,397	11,131,111	11,108,825	11,086,539	11,064,253	11,041,967	11,019,681	
6.	Average Net Investment		11,275,268	11,251,956	11,230,094	11,208,551	11,186,654	11,164,488	11,142,254	11,119,968	11,097,682	11,075,396	11,053,110	11,030,824	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		82,909	82,738	82,577	82,418	81,468	81,117	80,956	80,794	80,632	80,470	80,308	80,146	$976,533
	b. Debt Component Grossed Up For Taxes (F)		26,497	26,442	26,391	26,340	27,134	27,282	27,228	27,173	27,119	27,065	27,010	26,956	322,637
8.	Investment Expenses														
	a. Depreciation (C)		22,287	22,283	22,283	22,284	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	267,425
	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)		131,693	131,463	131,251	131,042	130,888	130,685	130,470	130,253	130,037	129,821	129,604	129,388	1,566,595
	a. Recoverable Costs Allocated to Energy		131,693	131,463	131,251	131,042	130,888	130,685	130,470	130,253	130,037	129,821	129,604	129,388	1,566,595
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		130,270	130,050	130,314	129,767	129,070	128,860	126,308	125,569	125,694	125,275	125,764	126,393	1,533,334
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$130,270	$130,050	$130,314	$129,767	$129,070	$128,860	$126,308	$125,569	$125,694	$125,275	$125,764	$126,393	$1,533,334

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($9,779,842)

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 2.4% and 2.3%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$18,372	$28,041	$35,113	($4,588)	$10,881	$9,433	$12,737	$28,876	$0	$0	$0	$0	$136,865
	b. Clearings to Plant		0	0	0	1,091,259	10,881	9,433	12,737	28,876	0	0	0	0	$1,153,186
	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)	$0	$0	$0	$0	$1,091,259	$1,102,140	$1,111,573	$1,124,310	$1,153,186	$1,153,186	$1,153,186	$1,153,186	$1,153,186	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(2,728)	(5,483)	(8,262)	(11,073)	(13,956)	(16,839)	(19,722)	(22,605)	
4.	CWIP - Non-Interest Bearing	1,016,321	1,034,693	1,060,734	1,095,847	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,016,321	1,034,693	1,060,734	1,095,847	1,091,259	1,099,412	1,106,090	1,116,048	1,142,113	1,139,230	1,136,347	1,133,464	1,130,581	
6.	Average Net Investment		1,025,507	1,047,714	1,078,291	1,093,553	1,095,336	1,102,751	1,111,069	1,129,081	1,140,672	1,137,789	1,134,906	1,132,023	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		7,541	7,704	7,929	8,041	7,977	8,012	8,073	8,204	8,288	8,267	8,246	8,225	$96,507
	b. Debt Component Grossed Up For Taxes (F)		2,410	2,462	2,534	2,570	2,657	2,695	2,715	2,759	2,787	2,780	2,773	2,766	31,908
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	2,728	2,755	2,779	2,811	2,883	2,883	2,883	2,883	22,605
	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)		9,951	10,166	10,463	10,611	13,362	13,462	13,567	13,774	13,958	13,930	13,902	13,874	151,020
	a. Recoverable Costs Allocated to Energy		9,951	10,166	10,463	10,611	13,362	13,462	13,567	13,774	13,958	13,930	13,902	13,874	151,020
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		9,843	10,057	10,388	10,508	13,176	13,274	13,134	13,279	13,492	13,442	13,490	13,553	147,636
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,843	$10,057	$10,388	$10,508	$13,176	$13,274	$13,134	$13,279	$13,492	$13,442	$13,490	$13,553	$147,636

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 315.40 ($1,153,186) and 345.81

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(C) Applicable depreciation rate is 3.3%, 2.6%, 2.4%, 3.0%, and 3.1%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

Form 42-8E
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For Project SO_2 Emissions Allowances
(in Dollars)

Line Description	Beginning of Period Amount	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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	0	92,691	0	0	0	0	0	0	0	$92,691
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	(44,985)	(44,720)	(44,531)	(44,393)	(44,150)	(43,925)	(43,674)	(43,227)	(42,705)	(42,155)	(41,625)	(41,065)	(40,594)	
3. Total Working Capital Balance	($44,985)	($44,720)	($44,531)	($44,393)	($44,150)	($43,925)	($43,674)	($43,227)	($42,705)	($42,155)	($41,625)	($41,065)	($40,594)	
4. Average Net Working Capital Balance		($44,852)	($44,626)	($44,462)	($44,271)	($44,037)	($43,799)	($43,450)	($42,966)	($42,430)	($41,890)	($41,345)	($40,830)	
5. Return on Average Net Working Capital Balance														
a. Equity Component Grossed Up For Taxes (A)		(330)	(328)	(327)	(326)	(321)	(318)	(316)	(312)	(308)	(304)	(300)	(297)	($3,787)
b. b. Debt Component Grossed Up For Taxes (E)		(105)	(105)	(104)	(104)	(107)	(107)	(106)	(105)	(104)	(102)	(101)	(100)	($1,250)
6. Total Return Component		(435)	(433)	(431)	(430)	(428)	(425)	(422)	(417)	(412)	(406)	(401)	(397)	($5,037)
7. Expenses:														
a. Gains		0	0	0	0	(92,691)	0	0	0	0	0	0	0	(92,691)
b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
c. SO_2 Allowance Expense		6,808	2,253	1,952	1,311	1,037	1,005	79,253	79,178	76,550	72,470	71,241	77,129	470,187
8. Net Expenses (B)		6,808	2,253	1,952	1,311	(91,654)	1,005	79,253	79,178	76,550	72,470	71,241	77,129	377,496
9. Total System Recoverable Expenses (Lines 6 + 7)		$6,373	$1,820	$1,521	$881	($92,082)	$580	$78,831	$78,761	$76,138	$72,064	$70,840	$76,732	$372,459
a. Recoverable Costs Allocated to Energy		6,373	1,820	1,521	881	(92,082)	580	78,831	78,761	76,138	72,064	70,840	76,732	372,459
b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10. Energy Jurisdictional Factor		0.9691913	0.9892481	0.9926581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9668046	0.9649832	0.9703716	0.9768498	0.9787224
11. Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232
12. Retail Energy-Related Recoverable Costs (C)		6,304	1,800	1,510	872	(90,803)	572	76,317	75,929	73,595	69,541	68,741	74,956	359,334
13. Retail Demand-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
14. Total Juris. Recoverable Costs (Lines 12 + 13)		$6,304	$1,800	$1,510	$872	($90,803)	$572	$76,317	$75,929	$73,595	$69,541	$68,741	$74,956	$359,334

Notes:

(A) Line 4 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002). Effective May 7, 2009, 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 1.63490).

(B) Line 8 is reported on Schedule 2P

(C) Line 9a x Line 10

(D) Line 9b x Line 11

(E) Line 4 x 2.82% x 1/12. Effective May 7, 2009, Line 4 x 2.9324% x 1/12.

DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 26 OF 26

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ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2010 THROUGH DECEMBER 2010

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 30
COMPANY Tampa Electric Company (Direct)
WITNESS Howard T. Bryant (HTB-3)
DATE 11/02/09

Form 42 - 1P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2010 to December 2010

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)	$18,046,706	$168,214	$18,214,920
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	57,074,029	149,366	57,223,395
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	75,120,735	317,580	75,438,315
2. True-up for Estimated Over/(Under) Recovery for the current period January 2009 to December 2009* (Form 42-2E, Line 5 + 6 + 10)	(9,193,784)	(85,345)	(9,279,129)
3. Final True-up for the period January 2008 to December 2008 (Form 42-1A, Line 3)	(7,994,185)	(118,808)	(8,112,993)
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2010 to December 2010 (Line 1 - Line 2- Line 3)	92,308,704	521,733	92,830,437
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$92,375,166	$522,109	$92,897,275

* 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. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

Form 42 - 2P

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	$291,800	$272,000	$371,100	$347,700	$402,800	$360,400	$299,700	$379,800	$361,700	$438,900	$364,600	$351,300	$4,241,800		$4,241,800
	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	46,720	42,098	46,759	47,134	48,787	47,057	48,742	48,742	47,056	48,796	45,037	46,636	563,564		563,564
	d. Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	692,600	620,400	577,300	504,900	602,200	602,300	484,400	634,700	635,600	621,500	636,200	631,200	7,443,300		7,443,300
	e. Big Bend PM Minimization and Monitoring	51,900	60,700	64,900	57,200	43,300	24,500	25,100	25,100	24,500	43,300	24,500	25,000	470,000		470,000
	f. Big Bend NO_x Emissions Reduction	58,000	58,000	8,000	40,500	115,500	28,000	8,000	8,000	8,000	8,000	28,000	28,000	396,000		396,000
	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	10,000	0	10,000	0	10,000	0	0	0	0	0	30,000	30,000	
	i. Polk NO_x Reduction	3,500	3,500	7,000	4,000	3,500	4,000	4,000	4,000	3,500	6,000	3,500	3,500	50,000		50,000
	j. Bayside SCR and Ammonia	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	114,000		114,000
	k. Big Bend Unit 4 SOFA	0	0	0	21,000	31,000	10,000	0	0	0	0	0	0	62,000		62,000
	l. Big Bend Unit 1 Pre-SCR	25,000	25,000	25,000	0	0	0	0	0	0	0	0	0	75,000		75,000
	m. Big Bend Unit 2 Pre-SCR	0	21,000	10,000	0	0	0	0	0	0	0	0	0	31,000		31,000
	n. Big Bend Unit 3 Pre-SCR	0	0	21,000	10,000	0	0	0	0	0	0	0	0	31,000		31,000
	o. Clean Water Act Section 316(b) Phase II Study	0	0	20,000	0	20,000	0	20,000	0	0	0	0	0	60,000	60,000	
	p. Arsenic Groundwater Standard Program	0	0	7,000	0	0	7,000	10,000	0	13,000	0	0	13,000	50,000	50,000	
	q. Big Bend 1 SCR	0	0	0	0	202,100	115,000	118,400	117,600	115,100	102,600	112,900	117,900	1,001,600		1,001,600
	r. Big Bend 2 SCR	149,200	98,500	134,100	125,400	141,100	146,800	151,300	150,200	146,900	129,800	144,100	150,700	1,668,100		1,668,100
	s. Big Bend 3 SCR	149,700	115,000	124,500	126,800	143,100	148,800	153,300	152,200	148,900	109,300	145,000	151,500	1,668,100		1,668,100
	t. Big Bend 4 SCR	72,400	57,000	61,900	38,300	52,200	71,200	73,600	73,100	71,300	65,000	69,900	72,800	778,700		778,700
	u. Clean Air Mercury Rule	0	0	2,000	0	0	2,000	0	0	2,000	0	0	2,000	8,000		8,000
2.	Total of O&M Activities	1,584,820	1,582,698	1,500,059	1,332,434	1,825,087	1,576,557	1,416,042	1,602,942	1,587,056	1,582,696	1,583,237	1,603,036	18,776,664	174,500	18,602,164
3.	Recoverable Costs Allocated to Energy	1,550,320	1,582,698	1,463,059	1,332,434	1,795,087	1,569,557	1,376,042	1,602,942	1,574,056	1,582,696	1,583,237	1,590,036	18,602,164		
	Recoverable Costs Allocated to Demand	34,500	0	37,000	0	30,000	7,000	40,000	0	13,000	0	0	13,000	174,500		
5.	Retail Energy Jurisdictional Factor	0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374			
6.	Retail Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735			
7.	Jurisdictional Energy Recoverable Costs (A)	1,516,039	1,539,605	1,426,059	1,293,422	1,728,486	1,523,593	1,332,635	1,546,121	1,522,216	1,528,253	1,536,911	1,553,366	18,046,706		
8.	Jurisdictional Demand Recoverable Costs (B)	33,257	0	35,667	0	28,919	6,748	38,559	0	12,532	0	0	12,532	168,214		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,549,296	$1,539,605	$1,461,726	$1,293,422	$1,757,405	$1,530,341	$1,371,194	$1,546,121	$1,534,748	$1,528,253	$1,536,911	$1,565,898	$18,214,920		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DOCKET NO. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 2

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	$64,538	$64,385	$64,232	$64,079	$63,925	$63,771	$63,619	$63,465	$63,312	$63,158	$63,005	$62,852	$764,341		$764,341
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124		422,124
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510		78,510
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079	$ 53,079	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302	87,302	
	f.	Phillips Upgrade Tank # 1 for FDEP	480	478	477	476	474	473	472	470	469	468	466	464	5,667	5,667	
	g.	Phillips Upgrade Tank # 4 for FDEP	754	751	750	747	745	743	740	738	736	734	731	730	8,899	8,899	
	h.	Big Bend Unit 1 Classifier Replacement	11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795		133,795
	i.	Big Bend Unit 2 Classifier Replacement	8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974		96,974
	j.	Big Bend Section 114 Mercury Testing Platform	1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303		13,303
	k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	736,939	737,118	737,289	735,721	741,734	739,684	737,635	735,585	733,536	731,487	729,437	727,387	8,823,552		8,823,552
	l.	Big Bend FGD Optimization and Utilization	208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526		2,475,526
	m.	Big Bend NO_x Emissions Reduction	67,476	67,390	67,304	67,217	67,130	67,043	66,957	66,870	66,784	66,697	66,610	66,524	804,002		804,002
	n.	Big Bend PM Minimization and Monitoring	89,789	89,654	89,452	89,249	89,046	88,843	88,640	88,437	88,234	88,032	87,829	87,626	1,064,831		1,064,831
	o.	Polk NO_x Emissions Reduction	16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609		195,609
	p.	Big Bend Unit 4 SOFA	26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962		317,962
	q.	Big Bend Unit 1 Pre-SCR	22,533	22,489	22,444	22,400	22,356	22,312	22,268	22,224	22,180	22,136	22,092	22,048	267,482		267,482
	r.	Big Bend Unit 2 Pre-SCR	18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590		213,590
	s.	Big Bend Unit 3 Pre-SCR	30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931		366,931
	t.	Big Bend Unit 1 SCR	0	0	0	0	889,336	1,186,187	1,185,685	1,183,181	1,180,677	1,178,174	1,175,670	1,173,167	9,152,077		9,152,077
	u.	Big Bend Unit 2 SCR	1,102,544	1,100,274	1,098,003	1,095,733	1,093,462	1,091,192	1,088,921	1,086,651	1,084,381	1,082,110	1,079,840	1,077,568	13,080,679		13,080,679
	v.	Big Bend Unit 3 SCR	901,949	900,329	898,710	897,090	895,469	893,849	892,230	890,610	888,989	887,369	885,750	884,130	10,716,474		10,716,474
	w.	Big Bend Unit 4 SCR	678,425	677,237	676,049	674,861	673,673	672,485	671,297	670,109	668,920	667,732	666,544	665,356	8,062,688		8,062,688
	x.	Big Bend FGD System Reliability	129,171	128,955	128,739	128,523	128,306	129,303	131,514	134,939	140,791	145,914	148,389	150,094	1,624,618		1,624,618
	y.	Clean Air Mercury Rule	13,956	14,037	14,107	14,225	14,197	14,169	14,141	14,111	14,083	14,055	14,026	13,998	169,105		169,105
	z.	SO_2 Emissions Allowances (B)	(393)	(390)	(387)	(385)	(382)	(378)	(375)	(372)	(369)	(365)	(362)	(358)	(4,516)		(4,516)
		Total Investment Projects - Recoverable Costs	4,183,936	4,177,658	4,171,288	4,163,230	5,051,939	5,341,316	5,334,556	5,327,001	5,321,879	5,316,031	5,307,509	5,298,261	58,994,604	$ 154,947	$ 58,839,657
3.		Recoverable Costs Allocated to Energy	4,170,852	4,164,606	4,158,266	4,150,238	5,038,980	5,328,388	5,321,659	5,314,136	5,309,045	5,303,227	5,294,739	5,285,521	58,839,657		
4.		Recoverable Costs Allocated to Demand	13,084	13,052	13,022	12,992	12,959	12,928	12,897	12,865	12,834	12,804	12,770	12,740	154,947		
5.		Retail Energy Jurisdictional Factor	0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374			
6.		Retail Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735			
7.		Jurisdictional Energy Recoverable Costs (C)	4,078,626	4,051,214	4,053,107	4,028,724	4,852,024	5,172,347	5,153,790	5,125,762	5,134,196	5,120,801	5,139,815	5,163,623	57,074,029		
8.		Jurisdictional Demand Recoverable Costs (D)	12,613	12,582	12,553	12,524	12,492	12,462	12,432	12,402	12,372	12,343	12,310	12,281	149,366		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$4,091,239	$4,063,796	$4,065,660	$4,041,248	$4,864,516	$5,184,809	$5,166,222	$5,138,164	$5,146,568	$5,133,144	$5,152,125	$5,175,904	$57,223,395		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8P, Line 9
(B) Project's Total Return Component on Form 42-8P, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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EXHIBIT NO. HTB-3
DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	$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)	$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	(3,211,293)	(3,227,086)	(3,242,879)	(3,258,672)	(3,274,465)	(3,290,258)	(3,306,051)	(3,321,844)	(3,337,637)	(3,353,430)	(3,369,223)	(3,385,016)	(3,400,809)	
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)	$5,028,365	5,012,572	4,996,779	4,980,986	4,965,193	4,949,400	4,933,607	4,917,814	4,902,021	4,886,228	4,870,435	4,854,642	4,838,849	
6.	Average Net Investment		5,020,469	5,004,676	4,988,883	4,973,090	4,957,297	4,941,504	4,925,711	4,909,918	4,894,125	4,878,332	4,862,539	4,846,746	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		36,477	36,362	36,248	36,133	36,018	35,903	35,789	35,674	35,559	35,444	35,330	35,215	$430,152
	b. Debt Component Grossed Up For Taxes (F)		12,268	12,230	12,191	12,153	12,114	12,075	12,037	11,998	11,960	11,921	11,882	11,844	144,673
8.	Investment Expenses														
	a. Depreciation (C)		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)		64,538	64,385	64,232	64,079	63,925	63,771	63,619	63,465	63,312	63,158	63,005	62,852	764,341
	a. Recoverable Costs Allocated to Energy		64,538	64,385	64,232	64,079	63,925	63,771	63,619	63,465	63,312	63,158	63,005	62,852	764,341
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		63,111	62,632	62,608	62,203	61,553	61,903	61,612	61,215	61,227	60,985	61,161	61,402	741,612
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$63,111	$62,632	$62,608	$62,203	$61,553	$61,903	$61,612	$61,215	$61,227	$60,985	$61,161	$61,402	$741,612

Notes:

(A) Applicable depreciable base for Big Bend; account 312.45 ($8,239,658)
(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 1.63490).
(C) Applicable depreciation rate is 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(2,695,310)	(2,708,719)	(2,722,128)	(2,735,537)	(2,748,946)	(2,762,355)	(2,775,764)	(2,789,173)	(2,802,582)	(2,815,991)	(2,829,400)	(2,842,809)	(2,856,218)	
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)	$2,322,424	2,309,015	2,295,606	2,282,197	2,268,788	2,255,379	2,241,970	2,228,561	2,215,152	2,201,743	2,188,334	2,174,925	2,161,516	
6.	Average Net Investment		2,315,720	2,302,311	2,288,902	2,275,493	2,262,084	2,248,675	2,235,266	2,221,857	2,208,448	2,195,039	2,181,630	2,168,221	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		16,825	16,728	16,630	16,533	16,436	16,338	16,241	16,143	16,046	15,948	15,851	15,754	$195,473
	b. Debt Component Grossed Up For Taxes (F)		5,659	5,626	5,593	5,561	5,528	5,495	5,462	5,429	5,397	5,364	5,331	5,298	65,743
8.	Investment Expenses														
	a. Depreciation (C)		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)		35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124
	a. Recoverable Costs Allocated to Energy		35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		35,099	34,789	34,731	34,464	34,061	34,210	34,004	33,741	33,704	33,527	33,579	33,666	409,575
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$35,099	$34,789	$34,731	$34,464	$34,061	$34,210	$34,004	$33,741	$33,704	$33,527	$33,579	$33,666	$409,575

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 1.63490).
(C) Applicable depreciation rates are 3.3% and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(339,461)	(340,977)	(342,493)	(344,009)	(345,525)	(347,041)	(348,557)	(350,073)	(351,589)	(353,105)	(354,621)	(356,137)	(357,653)	
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)	$526,750	525,234	523,718	522,202	520,686	519,170	517,654	516,138	514,622	513,106	511,590	510,074	508,558	
6.	Average Net Investment		525,992	524,476	522,960	521,444	519,928	518,412	516,896	515,380	513,864	512,348	510,832	509,316	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,822	3,811	3,800	3,789	3,778	3,767	3,756	3,745	3,734	3,723	3,712	3,701	$45,138
	b. Debt Component Grossed Up For Taxes (F)		1,285	1,282	1,278	1,274	1,271	1,267	1,263	1,259	1,256	1,252	1,248	1,245	15,180
8.	Investment Expenses														
	a. Depreciation (C)		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)		6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510
	a. Recoverable Costs Allocated to Energy		6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		6,477	6,429	6,427	6,386	6,321	6,358	6,329	6,289	6,292	6,268	6,287	6,313	76,176
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,477	$6,429	$6,427	$6,386	$6,321	$6,358	$6,329	$6,289	$6,292	$6,268	$6,287	$6,313	$76,176

Notes:

(A) Applicable depreciable base for Big Bend; account 315.44 ($866,211)
(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 1.63490).
(C) Applicable depreciation rate is 2.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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 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)	$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	(146,560)	(147,638)	(148,716)	(149,794)	(150,872)	(151,950)	(153,028)	(154,106)	(155,184)	(156,262)	(157,340)	(158,418)	(159,496)	
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)	$351,018	349,940	348,862	347,784	346,706	345,628	344,550	343,472	342,394	341,316	340,238	339,160	338,082	
6.	Average Net Investment		350,479	349,401	348,323	347,245	346,167	345,089	344,011	342,933	341,855	340,777	339,699	338,621	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,546	2,539	2,531	2,523	2,515	2,507	2,499	2,492	2,484	2,476	2,468	2,460	$30,040
	b. Debt Component Grossed Up For Taxes (F)		856	854	851	849	846	843	841	838	835	833	830	827	10,103
8.	Investment Expenses														
	a. Depreciation (C)		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)		4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079
	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		4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		4,319	4,310	4,299	4,290	4,279	4,268	4,259	4,249	4,239	4,229	4,218	4,208	51,167
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,319	$4,310	$4,299	$4,290	$4,279	$4,268	$4,259	$4,249	$4,239	$4,229	$4,218	$4,208	$51,167

Notes:

(A) Applicable depreciable base for Big Bend; account 312.40 ($497,578)
(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 1.63490).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(241,072)	(242,845)	(244,618)	(246,391)	(248,164)	(249,937)	(251,710)	(253,483)	(255,256)	(257,029)	(258,802)	(260,575)	(262,348)	
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)	$577,329	575,556	573,783	572,010	570,237	568,464	566,691	564,918	563,145	561,372	559,599	557,826	556,053	
6.	Average Net Investment		576,443	574,670	572,897	571,124	569,351	567,578	565,805	564,032	562,259	560,486	558,713	556,940	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,188	4,175	4,162	4,150	4,137	4,124	4,111	4,098	4,085	4,072	4,059	4,047	$49,408
	b. Debt Component Grossed Up For Taxes (F)		1,409	1,404	1,400	1,396	1,391	1,387	1,383	1,378	1,374	1,370	1,365	1,361	16,618
8.	Investment Expenses														
	a. Depreciation (C)		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)		7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302
	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		7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		7,104	7,087	7,071	7,055	7,038	7,022	7,005	6,988	6,971	6,955	6,938	6,922	84,156
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,104	$7,087	$7,071	$7,055	$7,038	$7,022	$7,005	$6,988	$6,971	$6,955	$6,938	$6,922	$84,156

Notes:

(A) Applicable depreciable base for Big Bend; account 312.40 ($818,401)
(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 1.63490).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(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)	$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	(22,536)	(22,679)	(22,822)	(22,965)	(23,108)	(23,251)	(23,394)	(23,537)	(23,680)	(23,823)	(23,966)	(24,109)	(24,252)	
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)	$34,741	34,598	34,455	34,312	34,169	34,026	33,883	33,740	33,597	33,454	33,311	33,168	33,025	
6.	Average Net Investment		34,670	34,527	34,384	34,241	34,098	33,955	33,812	33,669	33,526	33,383	33,240	33,097	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		252	251	250	249	248	247	246	245	244	243	242	240	$2,957
	b. Debt Component Grossed Up For Taxes (F)		85	84	84	84	83	83	83	82	82	82	81	81	994
8.	Investment Expenses														
	a. Depreciation (C)		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)		480	478	477	476	474	473	472	470	469	468	466	464	5,667
	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		480	478	477	476	474	473	472	470	469	468	466	464	5,667
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		463	461	460	459	457	456	455	453	452	451	449	447	5,463
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$463	$461	$460	$459	$457	$456	$455	$453	$452	$451	$449	$447	$5,463

Notes:

(A) Applicable depreciable base for Phillips; account 342.28 ($57,277)
(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 1.63490).
(C) Applicable depreciation rate is 3.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(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)	$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	(36,011)	(36,237)	(36,463)	(36,689)	(36,915)	(37,141)	(37,367)	(37,593)	(37,819)	(38,045)	(38,271)	(38,497)	(38,723)	
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)	$54,461	54,235	54,009	53,783	53,557	53,331	53,105	52,879	52,653	52,427	52,201	51,975	51,749	
6.	Average Net Investment		54,348	54,122	53,896	53,670	53,444	53,218	52,992	52,766	52,540	52,314	52,088	51,862	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		395	393	392	390	388	387	385	383	382	380	378	377	$4,630
	b. Debt Component Grossed Up For Taxes (F)		133	132	132	131	131	130	129	129	128	128	127	127	1,557
8.	Investment Expenses														
	a. Depreciation (C)		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)		754	751	750	747	745	743	740	738	736	734	731	730	8,899
	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		754	751	750	747	745	743	740	738	736	734	731	730	8,899
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		727	724	723	720	718	716	713	711	709	708	705	704	8,578
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$727	$724	$723	$720	$718	$716	$713	$711	$709	$708	$705	$704	$8,578

Notes:

(A) Applicable depreciable base for Phillips; account 342.28 ($90,472)
(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 1.63490).
(C) Applicable depreciation rate is 3.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(519,032)	(522,652)	(526,272)	(529,892)	(533,512)	(537,132)	(540,752)	(544,372)	(547,992)	(551,612)	(555,232)	(558,852)	(562,472)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$797,225	793,605	789,985	786,365	782,745	779,125	775,505	771,885	768,265	764,645	761,025	757,405	753,785	
6.	Average Net Investment		795,415	791,795	788,175	784,555	780,935	777,315	773,695	770,075	766,455	762,835	759,215	755,595	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,779	5,753	5,727	5,700	5,674	5,648	5,621	5,595	5,569	5,543	5,516	5,490	$67,615
	b. Debt Component Grossed Up For Taxes (F)		1,944	1,935	1,926	1,917	1,908	1,899	1,891	1,882	1,873	1,864	1,855	1,846	22,740
8.	Investment Expenses														
	a. Depreciation (C)		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)		11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795
	a. Recoverable Costs Allocated to Energy		11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		11,092	11,000	10,988	10,908	10,786	10,840	10,781	10,704	10,698	10,648	10,669	10,703	129,817
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,092	$11,000	$10,988	$10,908	$10,786	$10,840	$10,781	$10,704	$10,698	$10,648	$10,669	$10,703	$129,817

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41 ($1,316,257)
(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 1.63490).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(399,222)	(401,766)	(404,310)	(406,854)	(409,398)	(411,942)	(414,486)	(417,030)	(419,574)	(422,118)	(424,662)	(427,206)	(429,750)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$585,572	583,028	580,484	577,940	575,396	572,852	570,308	567,764	565,220	562,676	560,132	557,588	555,044	
6.	Average Net Investment		584,300	581,756	579,212	576,668	574,124	571,580	569,036	566,492	563,948	561,404	558,860	556,316	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,245	4,227	4,208	4,190	4,171	4,153	4,134	4,116	4,097	4,079	4,060	4,042	$49,722
	b. Debt Component Grossed Up For Taxes (F)		1,428	1,422	1,415	1,409	1,403	1,397	1,391	1,384	1,378	1,372	1,366	1,359	16,724
8.	Investment Expenses														
	a. Depreciation (C)		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)		8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974
	a. Recoverable Costs Allocated to Energy		8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		8,035	7,970	7,960	7,905	7,817	7,857	7,814	7,759	7,755	7,720	7,737	7,762	94,091
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,035	$7,970	$7,960	$7,905	$7,817	$7,857	$7,814	$7,759	$7,755	$7,720	$7,737	$7,762	$94,091

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42 ($984,794)
(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 1.63490).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(26,059)	(26,260)	(26,461)	(26,662)	(26,863)	(27,064)	(27,265)	(27,466)	(27,667)	(27,868)	(28,069)	(28,270)	(28,471)	
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)	$94,678	94,477	94,276	94,075	93,874	93,673	93,472	93,271	93,070	92,869	92,668	92,467	92,266	
6.	Average Net Investment		94,578	94,377	94,176	93,975	93,774	93,573	93,372	93,171	92,970	92,769	92,568	92,367	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		687	686	684	683	681	680	678	677	675	674	673	671	$8,149
	b. Debt Component Grossed Up For Taxes (F)		231	231	230	230	229	229	228	228	227	227	226	226	2,742
8.	Investment Expenses														
	a. Depreciation (C)		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)		1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303
	a. Recoverable Costs Allocated to Energy		1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		1,094	1,088	1,087	1,081	1,070	1,077	1,072	1,067	1,067	1,064	1,068	1,073	12,908
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,094	$1,088	$1,087	$1,081	$1,070	$1,077	$1,072	$1,067	$1,067	$1,064	$1,068	$1,073	$12,908

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40 ($120,737)
(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 1.63490).
(C) Applicable depreciation rate is 2.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD (Less Gypsum Revenue)
(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		$82,824	$360,416	$81,000	$2,026	$0	$0	$0	$0	$0	$0	$0	$0	$526,266
	b. Clearings to Plant		0	0	0	3,316,137	0	0	0	0	0	0	0	0	3,316,137
	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)	$84,032,642	$84,032,642	$84,032,642	$84,032,642	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	
3.	Less: Accumulated Depreciation	(31,778,233)	(31,981,312)	(32,184,391)	(32,387,470)	(32,590,549)	(32,801,642)	(33,012,735)	(33,223,828)	(33,434,921)	(33,646,014)	(33,857,107)	(34,068,200)	(34,279,293)	
4.	CWIP - Non-Interest Bearing	2,789,871	2,872,695	3,233,111	3,314,111	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5.	Net Investment (Lines 2 + 3 + 4)	$55,044,280	54,924,025	55,081,361	54,959,282	54,758,229	54,547,136	54,336,043	54,124,950	53,913,857	53,702,764	53,491,671	53,280,578	53,069,485	
6.	Average Net Investment		54,984,152	55,002,693	55,020,322	54,858,756	54,652,683	54,441,590	54,230,497	54,019,404	53,808,311	53,597,218	53,386,125	53,175,032	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		399,497	399,631	399,759	398,585	397,088	395,554	394,021	392,487	390,953	389,420	387,886	386,352	$4,731,233
	b. Debt Component Grossed Up For Taxes (F)		134,363	134,408	134,451	134,057	133,553	133,037	132,521	132,005	131,490	130,974	130,458	129,942	1,591,259
8.	Investment Expenses														
	a. Depreciation (C)		203,079	203,079	203,079	203,079	211,093	211,093	211,093	211,093	211,093	211,093	211,093	211,093	2,501,060
	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)		736,939	737,118	737,289	735,721	741,734	739,684	737,635	735,585	733,536	731,487	729,437	727,387	8,823,552
	a. Recoverable Costs Allocated to Energy		736,939	737,118	737,289	735,721	741,734	739,684	737,635	735,585	733,536	731,487	729,437	727,387	8,823,552
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		720,644	717,048	718,644	714,180	714,214	718,023	714,367	709,510	709,378	706,325	708,094	710,612	8,561,039
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$720,644	$717,048	$718,644	$714,180	$714,214	$718,023	$714,367	$709,510	$709,378	$706,325	$708,094	$710,612	$8,561,039

Notes:

(A) Applicable depreciable base for Big Bend; account 312.46 ($87,348,776)
(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 1.63490).
(C) Applicable depreciation rates are 2.9% .
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(4,531,789)	(4,573,431)	(4,615,073)	(4,656,715)	(4,698,357)	(4,739,999)	(4,781,641)	(4,823,283)	(4,864,925)	(4,906,567)	(4,948,209)	(4,989,851)	(5,031,493)	
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)	$17,207,948	17,166,306	17,124,664	17,083,022	17,041,380	16,999,738	16,958,096	16,916,454	16,874,812	16,833,170	16,791,528	16,749,886	16,708,244	
6.	Average Net Investment		17,187,127	17,145,485	17,103,843	17,062,201	17,020,559	16,978,917	16,937,275	16,895,633	16,853,991	16,812,349	16,770,707	16,729,065	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		124,876	124,573	124,271	123,968	123,666	123,363	123,061	122,758	122,455	122,153	121,850	121,548	$1,478,542
	b. Debt Component Grossed Up For Taxes (F)		42,000	41,898	41,796	41,694	41,593	41,491	41,389	41,287	41,186	41,084	40,982	40,880	497,280
8.	Investment Expenses														
	a. Depreciation (C)		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)		208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526
	a. Recoverable Costs Allocated to Energy		208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		203,907	202,447	202,456	201,234	199,225	200,449	199,591	198,396	198,522	197,831	198,491	199,364	2,401,913
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$203,907	$202,447	$202,456	$201,234	$199,225	$200,449	$199,591	$198,396	$198,522	$197,831	$198,491	$199,364	$2,401,913

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 1.63490).
(C) Applicable depreciation rates are 1.5% and 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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)	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	
3.	Less: Accumulated Depreciation	2,573,615	2,564,690	2,555,765	2,546,840	2,537,915	2,528,990	2,520,065	2,511,140	2,502,215	2,493,290	2,484,365	2,475,440	2,466,515	
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)	$6,034,918	6,025,993	6,017,068	6,008,143	5,999,218	5,990,293	5,981,368	5,972,443	5,963,518	5,954,593	5,945,668	5,936,743	5,927,818	
6.	Average Net Investment		6,030,456	6,021,531	6,012,606	6,003,681	5,994,756	5,985,831	5,976,906	5,967,981	5,959,056	5,950,131	5,941,206	5,932,281	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		43,815	43,750	43,686	43,621	43,556	43,491	43,426	43,361	43,297	43,232	43,167	43,102	$521,504
	b. Debt Component Grossed Up For Taxes (F)		14,736	14,715	14,693	14,671	14,649	14,627	14,606	14,584	14,562	14,540	14,518	14,497	175,398
8.	Investment Expenses														
	a. Depreciation (C)		8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	107,100
	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)		67,476	67,390	67,304	67,217	67,130	67,043	66,957	66,870	66,784	66,697	66,610	66,524	804,002
	a. Recoverable Costs Allocated to Energy		67,476	67,390	67,304	67,217	67,130	67,043	66,957	66,870	66,784	66,697	66,610	66,524	804,002
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		65,984	65,555	65,602	65,249	64,639	65,080	64,845	64,500	64,585	64,403	64,661	64,990	780,093
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$65,984	$65,555	$65,602	$65,249	$64,639	$65,080	$64,845	$64,500	$64,585	$64,403	$64,661	$64,990	$780,093

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($710,414)
(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 1.63490).
(C) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$10,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000
	b. Clearings to Plant		10,000	0	0	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	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,319,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	
3.	Less: Accumulated Depreciation	(1,216,996)	(1,237,876)	(1,258,776)	(1,279,676)	(1,300,576)	(1,321,476)	(1,342,376)	(1,363,276)	(1,384,176)	(1,405,076)	(1,425,976)	(1,446,876)	(1,467,776)	
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)	$7,102,640	7,091,760	7,070,860	7,049,960	7,029,060	7,008,160	6,987,260	6,966,360	6,945,460	6,924,560	6,903,660	6,882,760	6,861,860	
6.	Average Net Investment		7,097,200	7,081,310	7,060,410	7,039,510	7,018,610	6,997,710	6,976,810	6,955,910	6,935,010	6,914,110	6,893,210	6,872,310	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		51,566	51,450	51,299	51,147	50,995	50,843	50,691	50,539	50,387	50,236	50,084	49,932	$609,169
	b. Debt Component Grossed Up For Taxes (F)		17,343	17,304	17,253	17,202	17,151	17,100	17,049	16,998	16,947	16,896	16,845	16,794	204,882
8.	Investment Expenses														
	a. Depreciation (C)		20,880	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	250,780
	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)		89,789	89,654	89,452	89,249	89,046	88,843	88,640	88,437	88,234	88,032	87,829	87,626	1,064,831
	a. Recoverable Costs Allocated to Energy		89,789	89,654	89,452	89,249	89,046	88,843	88,640	88,437	88,234	88,032	87,829	87,626	1,064,831
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		87,804	87,213	87,190	86,636	85,742	86,241	85,844	85,302	85,328	85,004	85,259	85,605	1,033,168
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$87,804	$87,213	$87,190	$86,636	$85,742	$86,241	$85,844	$85,302	$85,328	$85,004	$85,259	$85,605	$1,033,168

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), 315.43 ($338,584), and 315.44 ($351,594)
(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 1.63490).
(C) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, 2.5%, and 2.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(311,706)	(316,130)	(320,554)	(324,978)	(329,402)	(333,826)	(338,250)	(342,674)	(347,098)	(351,522)	(355,946)	(360,370)	(364,794)	
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)	$1,249,767	1,245,343	1,240,919	1,236,495	1,232,071	1,227,647	1,223,223	1,218,799	1,214,375	1,209,951	1,205,527	1,201,103	1,196,679	
6.	Average Net Investment		1,247,555	1,243,131	1,238,707	1,234,283	1,229,859	1,225,435	1,221,011	1,216,587	1,212,163	1,207,739	1,203,315	1,198,891	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,064	9,032	9,000	8,968	8,936	8,904	8,871	8,839	8,807	8,775	8,743	8,711	$106,650
	b. Debt Component Grossed Up For Taxes (F)		3,049	3,038	3,027	3,016	3,005	2,995	2,984	2,973	2,962	2,951	2,941	2,930	35,871
8.	Investment Expenses														
	a. Depreciation (C)		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)		16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609
	a. Recoverable Costs Allocated to Energy		16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		16,171	16,045	16,035	15,928	15,758	15,845	15,765	15,660	15,660	15,594	15,637	15,694	189,792
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,171	$16,045	$16,035	$15,928	$15,758	$15,845	$15,765	$15,660	$15,660	$15,594	$15,637	$15,694	$189,792

Notes:
(A) Applicable depreciable base for Polk; account 342.81 ($1,561,473)
(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 1.63490).
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(326,042)	(331,159)	(336,276)	(341,393)	(346,510)	(351,627)	(356,744)	(361,861)	(366,978)	(372,095)	(377,212)	(382,329)	(387,446)	
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)	$2,232,688	2,227,571	2,222,454	2,217,337	2,212,220	2,207,103	2,201,986	2,196,869	2,191,752	2,186,635	2,181,518	2,176,401	2,171,284	
6.	Average Net Investment		2,230,130	2,225,013	2,219,896	2,214,779	2,209,662	2,204,545	2,199,428	2,194,311	2,189,194	2,184,077	2,178,960	2,173,843	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		16,203	16,166	16,129	16,092	16,055	16,017	15,980	15,943	15,906	15,869	15,832	15,794	$191,986
	b. Debt Component Grossed Up For Taxes (F)		5,450	5,437	5,425	5,412	5,400	5,387	5,375	5,362	5,350	5,337	5,325	5,312	64,572
8.	Investment Expenses														
	a. Depreciation (C)		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)		26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962
	a. Recoverable Costs Allocated to Energy		26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		26,178	25,992	25,997	25,842	25,586	25,744	25,637	25,485	25,504	25,418	25,505	25,618	308,506
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$26,178	$25,992	$25,997	$25,842	$25,586	$25,744	$25,637	$25,485	$25,504	$25,418	$25,505	$25,618	$308,506

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($2,558,730)
(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 1.63490).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	
	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	(161,005)	(165,540)	(170,075)	(174,610)	(179,145)	(183,680)	(188,215)	(192,750)	(197,285)	(201,820)	(206,355)	(210,890)	(215,425)	
4.	CWIP - Non-Interest Bearing	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	
5.	Net Investment (Lines 2 + 3 + 4)	$1,855,883	1,851,348	1,846,813	1,842,278	1,837,743	1,833,208	1,828,673	1,824,138	1,819,603	1,815,068	1,810,533	1,805,998	1,801,463	
6.	Average Net Investment		1,853,616	1,849,081	1,844,546	1,840,011	1,835,476	1,830,941	1,826,406	1,821,871	1,817,336	1,812,801	1,808,266	1,803,731	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		13,468	13,435	13,402	13,369	13,336	13,303	13,270	13,237	13,204	13,171	13,138	13,105	$159,438
	b. Debt Component Grossed Up For Taxes (F)		4,530	4,519	4,507	4,496	4,485	4,474	4,463	4,452	4,441	4,430	4,419	4,408	53,624
8.	Investment Expenses														
	a. Depreciation (C)		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)		22,533	22,489	22,444	22,400	22,356	22,312	22,268	22,224	22,180	22,136	22,092	22,048	267,482
	a. Recoverable Costs Allocated to Energy		22,533	22,489	22,444	22,400	22,356	22,312	22,268	22,224	22,180	22,136	22,092	22,048	267,482
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		22,035	21,877	21,876	21,744	21,527	21,659	21,566	21,436	21,450	21,375	21,446	21,540	259,531
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$22,035	$21,877	$21,876	$21,744	$21,527	$21,659	$21,566	$21,436	$21,450	$21,375	$21,446	$21,540	$259,531

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41 ($1,649,121)
(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 1.63490).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	
	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	(145,088)	(149,175)	(153,262)	(157,349)	(161,436)	(165,523)	(169,610)	(173,697)	(177,784)	(181,871)	(185,958)	(190,045)	(194,132)	
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)	$1,436,799	1,432,712	1,428,625	1,424,538	1,420,451	1,416,364	1,412,277	1,408,190	1,404,103	1,400,016	1,395,929	1,391,842	1,387,755	
6.	Average Net Investment		1,434,756	1,430,669	1,426,582	1,422,495	1,418,408	1,414,321	1,410,234	1,406,147	1,402,060	1,397,973	1,393,886	1,389,799	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,424	10,395	10,365	10,335	10,306	10,276	10,246	10,217	10,187	10,157	10,128	10,098	$123,134
	b. Debt Component Grossed Up For Taxes (F)		3,506	3,496	3,486	3,476	3,466	3,456	3,446	3,436	3,426	3,416	3,406	3,396	41,412
8.	Investment Expenses														
	a. Depreciation (C)		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)		18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590
	a. Recoverable Costs Allocated to Energy		18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		17,619	17,489	17,484	17,374	17,196	17,297	17,218	17,111	17,117	17,053	17,105	17,176	207,239
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,619	$17,489	$17,484	$17,374	$17,196	$17,297	$17,218	$17,111	$17,117	$17,053	$17,105	$17,176	$207,239

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42 ($1,581,887)
(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 1.63490).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(120,266)	(126,071)	(131,876)	(137,681)	(143,486)	(149,291)	(155,096)	(160,901)	(166,706)	(172,511)	(178,316)	(184,121)	(189,926)	
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)	$2,586,241	2,580,436	2,574,631	2,568,826	2,563,021	2,557,216	2,551,411	2,545,606	2,539,801	2,533,996	2,528,191	2,522,386	2,516,581	
6.	Average Net Investment		2,583,339	2,577,534	2,571,729	2,565,924	2,560,119	2,554,314	2,548,509	2,542,704	2,536,899	2,531,094	2,525,289	2,519,484	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,770	18,728	18,685	18,643	18,601	18,559	18,517	18,474	18,432	18,390	18,348	18,306	$222,453
	b. Debt Component Grossed Up For Taxes (F)		6,313	6,299	6,284	6,270	6,256	6,242	6,228	6,214	6,199	6,185	6,171	6,157	74,818
8.	Investment Expenses														
	a. Depreciation (C)		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)		30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931
	a. Recoverable Costs Allocated to Energy		30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		30,205	29,993	29,996	29,819	29,524	29,710	29,586	29,412	29,434	29,335	29,437	29,570	356,021
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$30,205	$29,993	$29,996	$29,819	$29,524	$29,710	$29,586	$29,412	$29,434	$29,335	$29,437	$29,570	$356,021

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 1.63490).
(C) Applicable depreciation rate is 2.6% and 2.5%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$7,027,032	$4,910,234	$1,815,814	$1,552,189	$262,711	$262,710	$0	$0	$0	$0	$0	$0	$15,830,690
	b. Clearings to Plant		0	0	0	0	95,683,666	262,710	0	0	0	0	0	0	$95,946,376
	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)	$72,203,171	$79,230,203	$84,140,437	$85,956,251	$87,508,440	$95,683,666	$95,946,376	$95,946,376	$95,946,376	$95,946,376	$95,946,376	$95,946,376	$95,946,376	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	(257,135)	(514,993)	(772,851)	(1,030,709)	(1,288,567)	(1,546,425)	(1,804,283)	
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)	$72,203,171	79,230,203	84,140,437	85,956,251	87,508,440	95,683,666	95,689,241	95,431,383	95,173,525	94,915,667	94,657,809	94,399,951	94,142,093	
6.	Average Net Investment		75,716,687	81,685,320	85,048,344	86,732,345	91,596,053	95,686,453	95,560,312	95,302,454	95,044,596	94,786,738	94,528,880	94,271,022	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	665,506	695,226	694,309	692,436	690,562	688,689	686,815	684,942	$5,498,485
	b. Debt Component Grossed Up For Taxes (F)		0	0	0	0	223,830	233,826	233,518	232,887	232,257	231,627	230,997	230,367	1,849,309
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	257,135	257,858	257,858	257,858	257,858	257,858	257,858	1,804,283
	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)		0	0	0	0	889,336	1,186,187	1,185,685	1,183,181	1,180,677	1,178,174	1,175,670	1,173,167	9,152,077
	a. Recoverable Costs Allocated to Energy		0	0	0	0	889,336	1,186,187	1,185,685	1,183,181	1,180,677	1,178,174	1,175,670	1,173,167	9,152,077
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	856,340	1,151,450	1,148,283	1,141,240	1,141,792	1,137,646	1,141,270	1,146,111	8,864,132
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (G)		$0	$0	$0	$0	$856,340	$1,151,450	$1,148,283	$1,141,240	$1,141,792	$1,137,646	$1,141,270	$1,146,111	$8,864,132

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 ($86,954,400) and 315.41 ($8,991,976).
(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 1.63490).
(C) Applicable depreciation rate are 3.3% and 2.5%.
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.
(G) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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)	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	
3.	Less: Accumulated Depreciation	(933,071)	(1,166,916)	(1,400,761)	(1,634,606)	(1,868,451)	(2,102,296)	(2,336,141)	(2,569,986)	(2,803,831)	(3,037,676)	(3,271,521)	(3,505,366)	(3,739,211)	
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)	$89,587,432	89,353,587	89,119,742	88,885,897	88,652,052	88,418,207	88,184,362	87,950,517	87,716,672	87,482,827	87,248,982	87,015,137	86,781,292	
6.	Average Net Investment		89,470,510	89,236,665	89,002,820	88,768,975	88,535,130	88,301,285	88,067,440	87,833,595	87,599,750	87,365,905	87,132,060	86,898,215	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		650,063	648,364	646,665	644,966	643,267	641,568	639,869	638,170	636,471	634,772	633,073	631,373	$7,688,621
	b. Debt Component Grossed Up For Taxes (F)		218,636	218,065	217,493	216,922	216,350	215,779	215,207	214,636	214,065	213,493	212,922	212,350	2,585,918
8.	Investment Expenses														
	a. Depreciation (C)		233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	2,806,140
	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)		1,102,544	1,100,274	1,098,003	1,095,733	1,093,462	1,091,192	1,088,921	1,086,651	1,084,381	1,082,110	1,079,840	1,077,568	13,080,679
	a. Recoverable Costs Allocated to Energy		1,102,544	1,100,274	1,098,003	1,095,733	1,093,462	1,091,192	1,088,921	1,086,651	1,084,381	1,082,110	1,079,840	1,077,568	13,080,679
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		1,078,164	1,070,316	1,070,235	1,063,651	1,052,892	1,059,237	1,054,572	1,048,132	1,048,668	1,044,886	1,048,244	1,052,716	12,691,713
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,078,164	$1,070,316	$1,070,235	$1,063,651	$1,052,892	$1,059,237	$1,054,572	$1,048,132	$1,048,668	$1,044,886	$1,048,244	$1,052,716	$12,691,713

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 ($90,520,503)
(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 1.63490).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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)	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	
3.	Less: Accumulated Depreciation	(2,914,986)	(3,081,834)	(3,248,682)	(3,415,530)	(3,582,378)	(3,749,226)	(3,916,074)	(4,082,922)	(4,249,770)	(4,416,618)	(4,583,466)	(4,750,314)	(4,917,162)	
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)	$75,794,223	75,627,375	75,460,527	75,293,679	75,126,831	74,959,983	74,793,135	74,626,287	74,459,439	74,292,591	74,125,743	73,958,895	73,792,047	
6.	Average Net Investment		75,710,799	75,543,951	75,377,103	75,210,255	75,043,407	74,876,559	74,709,711	74,542,863	74,376,015	74,209,167	74,042,319	73,875,471	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		550,089	548,877	547,665	546,453	545,240	544,028	542,816	541,604	540,391	539,179	537,967	536,755	$6,521,064
	b. Debt Component Grossed Up For Taxes (E)		185,012	184,604	184,197	183,789	183,381	182,973	182,566	182,158	181,750	181,342	180,935	180,527	2,193,234
8.	Investment Expenses														
	a. Depreciation (C)		166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	2,002,176
	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)		901,949	900,329	898,710	897,090	895,469	893,849	892,230	890,610	888,989	887,369	885,750	884,130	10,716,474
	a. Recoverable Costs Allocated to Energy		901,949	900,329	898,710	897,090	895,469	893,849	892,230	890,610	888,989	887,369	885,750	884,130	10,716,474
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		882,005	875,815	875,982	870,824	862,245	867,673	864,085	859,040	859,711	856,844	859,833	863,740	10,397,797
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$882,005	$875,815	$875,982	$870,824	$862,245	$867,673	$864,085	$859,040	$859,711	$856,844	$859,833	$863,740	$10,397,797

Notes:

(A) Applicable depreciable base for Big Bend; account 311.43 ($3,162,013) and 312.43 ($75,547,196)
(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 1.63490).
(C) Applicable depreciation rates are 1.2% and 2.6%
(D) Line 9a x Line 10
(E) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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)	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	
3.	Less: Accumulated Depreciation	(3,851,689)	(3,974,056)	(4,096,423)	(4,218,790)	(4,341,157)	(4,463,524)	(4,585,891)	(4,708,258)	(4,830,625)	(4,952,992)	(5,075,359)	(5,197,726)	(5,320,093)	
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)	$57,331,648	57,209,281	57,086,914	56,964,547	56,842,180	56,719,813	56,597,446	56,475,079	56,352,712	56,230,345	56,107,978	55,985,611	55,863,244	
6.	Average Net Investment		57,270,465	57,148,098	57,025,731	56,903,364	56,780,997	56,658,630	56,536,263	56,413,896	56,291,529	56,169,162	56,046,795	55,924,428	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		416,108	415,219	414,330	413,441	412,552	411,663	410,774	409,885	408,995	408,106	407,217	406,328	$4,934,618
	b. Debt Component Grossed Up For Taxes (F)		139,950	139,651	139,352	139,053	138,754	138,455	138,156	137,857	137,558	137,259	136,960	136,661	1,659,666
8.	Investment Expenses														
	a. Depreciation (C)		122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	1,468,404
	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)		678,425	677,237	676,049	674,861	673,673	672,485	671,297	670,109	668,920	667,732	666,544	665,356	8,062,688
	a. Recoverable Costs Allocated to Energy		678,425	677,237	676,049	674,861	673,673	672,485	671,297	670,109	668,920	667,732	666,544	665,356	8,062,688
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		663,424	658,797	658,952	655,102	648,678	652,791	650,121	646,355	646,890	644,763	647,041	650,011	7,822,925
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$663,424	$658,797	$658,952	$655,102	$648,678	$652,791	$650,121	$646,355	$646,890	$644,763	$647,041	$650,011	$7,822,925

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($61,183,337)
(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 1.63490).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	$250,000	$250,000	$500,000	$750,000	$350,000	$200,000	$200,000	$2,500,000
	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)	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	
3.	Less: Accumulated Depreciation	(560,953)	(583,239)	(605,525)	(627,811)	(650,097)	(672,383)	(694,669)	(716,955)	(739,241)	(761,527)	(783,813)	(806,099)	(828,385)	
4.	CWIP - Non-Interest Bearing	16,183	16,183	16,183	16,183	16,183	16,183	266,183	516,183	1,016,183	1,766,183	2,116,183	2,316,183	2,516,183	
5.	Net Investment (Lines 2 + 3 + 4)	$11,019,681	10,997,395	10,975,109	10,952,823	10,930,537	10,908,251	11,135,965	11,363,679	11,841,393	12,569,107	12,896,821	13,074,535	13,252,249	
6.	Average Net Investment		11,008,538	10,986,252	10,963,966	10,941,680	10,919,394	11,022,108	11,249,822	11,602,536	12,205,250	12,732,964	12,985,678	13,163,392	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		79,984	79,822	79,661	79,499	79,337	80,083	81,737	84,300	88,679	92,513	94,350	95,641	$1,015,606
	b. Debt Component Grossed Up For Taxes (F)		26,901	26,847	26,792	26,738	26,683	26,934	27,491	28,353	29,826	31,115	31,733	32,167	341,580
8.	Investment Expenses														
	a. Depreciation (C)		22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	267,432
	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)		129,171	128,955	128,739	128,523	128,306	129,303	131,514	134,939	140,791	145,914	148,369	150,094	1,624,618
	a. Recoverable Costs Allocated to Energy		129,171	128,955	128,739	128,523	128,306	129,303	131,514	134,939	140,791	145,914	148,369	150,094	1,624,618
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		126,315	125,444	125,483	124,760	123,546	125,516	127,365	130,156	136,154	140,895	144,028	146,632	1,576,294
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$126,315	$125,444	$125,483	$124,760	$123,546	$125,516	$127,365	$130,156	$136,154	$140,895	$144,028	$146,632	$1,576,294

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($10,108,242)
(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 1.63490).
(C) Applicable depreciation rate is 2.4% and 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,000
	b. Clearings to Plant		0	0	20,000	0	0	0	0	0	0	0	0	0	$20,000
	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)	$1,153,186	$1,153,186	$1,153,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	
3.	Less: Accumulated Depreciation	(22,605)	(2,883)	(5,766)	(8,649)	(11,582)	(14,515)	(17,448)	(20,381)	(23,314)	(26,247)	(29,180)	(32,113)	(35,046)	
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)	$1,130,581	1,150,303	1,147,420	1,164,537	1,161,604	1,158,671	1,155,738	1,152,805	1,149,872	1,146,939	1,144,006	1,141,073	1,138,140	
6.	Average Net Investment		1,140,442	1,148,862	1,155,979	1,163,071	1,160,138	1,157,205	1,154,272	1,151,339	1,148,406	1,145,473	1,142,540	1,139,607	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,286	8,347	8,399	8,450	8,429	8,408	8,387	8,365	8,344	8,323	8,301	8,280	$100,319
	b. Debt Component Grossed Up For Taxes (F)		2,787	2,807	2,825	2,842	2,835	2,828	2,821	2,813	2,806	2,799	2,792	2,785	33,740
8.	Investment Expenses														
	a. Depreciation (C)		2,883	2,883	2,883	2,933	2,933	2,933	2,933	2,933	2,933	2,933	2,933	2,933	35,046
	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)		13,956	14,037	14,107	14,225	14,197	14,169	14,141	14,111	14,083	14,055	14,026	13,998	169,105
	a. Recoverable Costs Allocated to Energy		13,956	14,037	14,107	14,225	14,197	14,169	14,141	14,111	14,083	14,055	14,026	13,998	169,105
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		13,647	13,655	13,750	13,809	13,670	13,754	13,695	13,611	13,619	13,572	13,616	13,675	164,073
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,647	$13,655	$13,750	$13,809	$13,670	$13,754	$13,695	$13,611	$13,619	$13,572	$13,616	$13,675	$164,073

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 315.40 ($1,173,186) and 345.81
(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 1.63490).
(C) Applicable depreciation rate is 3.3%, 2.6%, 2.4%, 3.0%, and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January 10	Projected February 10	Projected March 10	Projected April 10	Projected May 10	Projected June 10	Projected July 10	Projected August 10	Projected September 10	Projected October 10	Projected November 10	Projected December 10	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	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 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 - Gain	(40,594)	(40,314)	(40,012)	(39,771)	(39,504)	(39,191)	(38,848)	(38,490)	(38,132)	(37,788)	(37,484)	(37,121)	(36,757)	
3.	Total Working Capital Balance	($40,594)	($40,314)	($40,012)	($39,771)	($39,504)	($39,191)	($38,848)	($38,490)	($38,132)	($37,788)	($37,484)	($37,121)	($36,757)	
4.	Average Net Working Capital Balance		($40,454)	($40,163)	($39,891)	($39,638)	($39,348)	($39,019)	($38,669)	($38,311)	($37,960)	($37,636)	($37,303)	($36,939)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(294)	(292)	(290)	(288)	(286)	(283)	(281)	(278)	(276)	(273)	(271)	(268)	($3,380)
	b. b. Debt Component Grossed Up For Taxes (E)		(99)	(98)	(97)	(97)	(96)	(95)	(94)	(94)	(93)	(92)	(91)	(90)	($1,136)
6.	Total Return Component		(393)	(390)	(387)	(385)	(382)	(378)	(375)	(372)	(369)	(365)	(362)	(358)	($4,516)
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		46,720	42,098	46,759	47,134	48,787	47,057	48,742	48,742	47,056	48,796	45,037	46,636	563,564
8.	Net Expenses (B)		46,720	42,098	46,759	47,134	48,787	47,057	48,742	48,742	47,056	48,796	45,037	46,636	563,564
9.	Total System Recoverable Expenses (Lines 6 + 7)		$46,327	$41,708	$46,372	$46,749	$48,405	$46,679	$48,367	$48,370	$46,687	$48,431	$44,675	$46,278	$559,048
	a. Recoverable Costs Allocated to Energy		46,327	41,708	46,372	46,749	48,405	46,679	48,367	48,370	46,687	48,431	44,675	46,278	559,048
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	0.9702548
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735
12.	Retail Energy-Related Recoverable Costs (C)		45,303	40,572	45,199	45,380	46,609	45,312	46,841	46,655	45,149	46,765	43,368	45,211	542,364
13.	Retail Demand-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		$45,303	$40,572	$45,199	$45,380	$46,609	$45,312	$46,841	$46,655	$45,149	$46,765	$43,368	$45,211	$542,364

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 1.63490).
(B) Line 8 is reported on Schedule 2P
(C) Line 9a x Line 10
(D) Line 9b x Line 11
(E) Line 4 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009, is $786,289 compared to the original projection of $786,042, resulting in an insignificant variance.

The actual/estimated O&M expense for the period January 2009 through December 2009 is $3,351,790 compared to the original projection of $3,658,000 representing a variance of 8.4 percent. This variance is due to a lower cost of consumables for gypsum production as well as a decrease in maintenance costs.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010, is expected to be $764,341.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $4,241,800.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $440,808 compared to the original projection of $440,693, resulting in an insignificant variance.

The actual/estimated O&M expense for this project for the period January 2009 through December 2009 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 2010 through December 2010 is projected to be $422,124.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $80,611 compared to the original projection of $80,584, resulting in an insignificant variance.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $78,510.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $138,835 compared to the original projection of $138,796, resulting in an insignificant variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $133,795.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $100,518 compared to the original projection of $100,489 representing no variance.

Progress Summary: The project was placed in-service May 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $96,974.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $8,921,117 compared to the original projection of $8,960,005, representing an insignificant variance.

The actual/estimated O&M expense for the period January 2009 through December 2009 is $8,386,537 as compared to the original estimate of $7,482,800 resulting in a variance of 12.1 percent. This variance is primarily due to the re-allocation of 2008 maintenance activities with the scheduled outages for 2009.

Progress Summary: The project was placed in-service in December 1999.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $8,823,552.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $7,443,300.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009, is $13,584 compared to the original projection of $13,577, representing an insignificant variance.

Progress Summary: The project was placed in-service in December 1999 and was completed in May 2000.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $13,303.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $2,533,290 compared to the original projection of $2,532,454, representing an insignificant variance.

Progress Summary: The project was placed in-service in January 2002.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $2,475,526.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $1,086,037 as compared to the original projection of $1,124,629 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2009 through December 2009 is $467,907 as compared to the original projection of $455,000, representing an insignificant variance.

Progress Summary: This project was placed in-service July 2005.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $1,064,831.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $470,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $802,153 as compared to the original projection of $793,965 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2009 through December 2009 is $361,773 as compared to the original projection of $358,000, representing an insignificant variance.

Progress Summary: The project was placed in-service January 2006.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $804,002.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $396,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $54,575 compared to the original projection of $54,560, representing an insignificant variance.

Progress Summary: The project was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $53,079.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $89,767 compared to the original projection of $89,738, representing an insignificant variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $87,302.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009, is $5,862 compared to the original projection of $5,859, representing an insignificant variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $5,667.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $9,215 compared to the original projection of $9,211, representing an insignificant variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $8,899.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is ($5,037) compared to the original projection of ($1,669) representing a 201.8 percent variance. The variance is due to the sale of SO_2 allowances originally projected to occur in 2009 but transpired throughout 2008.

The actual/estimated O&M for the period January 2009 through December 2009 is $377,496 compared to the original projection of ($12,123,542) representing a variance of 103.1 percent. The significant variance is driven by the revenue shortfall precipitated by a significant market decline in SO_2 emission allowance prices.

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 2010 through December 2010 is projected to be ($4,516).

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $563,564.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 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 2010 through December 2010 are projected to be $34,500.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $194,066 compared to the original projection of $50,000, which represents a variance of 288.1 percent. The variance is due to the delayed invoicing from contractors.

Progress Summary: This project was approved by the Commission in Docket No. 010593-EI on September 4, 2001. The project is expected to continue through at least 2010.

Projections: Estimated O&M costs for the period January 2010 through December 2010 are projected to be $30,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $201,759 as compared to the original projection of $201,701, representing an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $49,036 compared to the original projection of $75,000, which represents a variance of 34.6 percent. The variance is due to the need for less maintenance than originally anticipated.

Progress Summary: The project was placed in-service January 2005.

Project Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $195,609.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $50,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $122,057 compared to the original projection of $82,000 resulting in a variance of 48.9 percent. The variance is due to the increase in price and consumption of ammonia.

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 2010 through December 2010 are projected to be $114,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $325,057 compared to the original projection of $324,949, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $25,718 compared to the original projection of $50,000, which represents a variance of 48.6 percent. This variance is due to a correction made to the General Ledger for a cost inadvertently booked against the project.

Progress Summary: The project was placed in-service November 2004.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $317,962.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $62,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2010 through 2010. 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 2009 through December 2009 is $273,776 compared to the original projection of $279,459, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $77,000 compared to the original projection of $77,000 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 2010 through December 2010 is projected to be $267,482.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $75,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2010 through 2010. 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 2009 through December 2009 is $219,267 compared to the original projection of $219,196, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $67,722 compared to the original projection of $77,000, which represents a variance of 12.0 percent. This variance is due to the delay of the in-service date for the capital project.

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 2010 through December 2010 is projected to be $213,590.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $31,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2010 through 2010. 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 2009 through December 2009 is $378,117 compared to the original projection of $279,459, resulting in an insignificant variance.

No O&M costs are anticipated for the period January 2009 through December 2009.

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 2010 through December 2010 is projected to be $366,931.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $31,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $47,240 compared to the original projection of $150,000, which represents a variance of 68.5 percent. This variance is due to the decrease in contractor costs to complete the impingement study reports.

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 2010 through December 2010 are projected to be $60,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2010 through 2010. 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 May 2010.

Project Accomplishments:

Fiscal Expenditures: Based on the Commission's previous ruling in Docket No. 980693-EI, Tampa Electric will not seek ECRC recovery of capital costs for this project until May 2010, the expected in-service date for the project. At that time, the associated depreciation expense and allowance for funds used during construction will be requested for ECRC recovery.

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 2010 through December 2010 is projected to be $9,152,077.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $1,001,600.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2010 through 2010. 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 April 2010.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $4,884,018 compared to the original projection of $8,618,125, which represents variance of 43.3 percent. This variance is due to the delay in commercial operation.

The actual/estimated O&M for the period January 2009 through December 2009 is $728,900 compared to the original projection of $1,807,700 representing a variance of 59.7 percent. The variance is due to the delay in commercial operation.

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 2010 through December 2010 is projected to be $13,080,679.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $1,668,100.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2010 through 2010. 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 May 2010.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $10,944,895 compared to the original projection of $11,145,102, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $1,437,288 compared to the original projection of $2,204,900 representing a variance of 34.8 percent. The variance is due to less ammonia used than originally anticipated.

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 2010 through December 2010 is projected to be $10,716,474.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $1,668,100.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2010 through 2010. 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 June 2010.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $8,232,257 compared to the original projection of $8,232,074, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $678,922 compared to the original projection of $1,252,800 representing a variance of 45.8 percent. The variance is due to the decreased usage of ammonia.

Progress Summary: This project went in to service in May 2007.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $8,062,688.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $778,700.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $115,846 compared to the original projection of $114,000, resulting in an insignificant variance.

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 2010 through December 2010 are projected to be $50,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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, 2010 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 2009 through December 2009 is $1,566,595 compared to the original projection of $1,587,494, resulting in an insignificant variance.

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 2010 through December 2010 is projected to be $1,624,618.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 CAA Section 111, effective January 2009. CAMR will permanently cap and reduce mercury emissions nation-wide in two phases: Phase I cap is 38 tons per year with a compliance date of 2010 and Phase II cap is 15 tons per year with a compliance date of 2018. Tampa Electric's Big Bend and Polk Power Stations will be affected by the nation-wide mercury emissions reduction rule. According to Rule, the company must install emission-monitoring systems that sample mercury found in flue gas on Big Bend Units 1 through 4 and Polk Unit 1.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $151,020 compared to the original projection of $110,652, which represents a variance of 36.5 percent. The variance is due to the installation of the equipment to collect baseline data in preparation for rule changes.

Progress Summary: A petition was filed on August 30, 2006 seeking Commission approval of cost recovery through the ECRC for the new CAMR program.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $169,105.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $8,000.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2010 to December 2010

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	52.81%	8,824,328	8,824,328	1,908	1.08536	1.05482	9,308,101	2,070	46.17%	54.81%	52.65%
GS, TS	54.51%	1,030,757	1,030,757	216	1.08536	1.05482	1,087,266	234	5.39%	6.20%	6.00%
GSD, SBF	74.30%	8,039,231	8,026,251	1,204	1.08085	1.05106	8,449,676	1,302	41.92%	34.47%	36.33%
IS	75.80%	1,061,694	1,043,681	160	1.03968	1.02124	1,084,239	166	5.38%	4.40%	4.65%
LS1	498.93%	218,062	218,062	5	1.08536	1.05482	230,017	5	1.14%	0.13%	0.38%
TOTAL *		19,174,072	19,143,079	3,493			20,159,299	3,777	100.00%	100.00%	100.00%

Notes: (1) Average 12 CP load factor based on 2009 projected calendar data
(2) Projected MWh sales for the period January 2010 to December 2010
(3) Effective sales at secondary level for the period January 2010 to December 2010.
(4) Based on 12 months average CP at meter
(5) Based on 2009 proposed load research data
(6) Average 12 CP load factor based on 2009 proposed load research data
(7) Projected MWh sales for the period January 2010 to December 2010
(8) Column 4 x Column 5
(9) Based on 2009 proposed load research data
(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. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 6

Form 42 - 7P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2010 to December 2010

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	46.170%	52.65%	42,648,484	274,890	42,923,374	8,824,328	8,824,328	**0.486**
GS, TS	5.390%	6.00%	4,978,890	31,313	5,010,203	1,030,757	1,030,757	**0.486**
GSD, SBF	41.920%	36.33%	38,722,644	189,695	38,912,339	8,039,231	8,026,251	
Secondary								**0.485**
Primary								**0.480**
Transmission								**0.475**
IS	5.380%	4.65%	4,969,652	24,252	4,993,904	1,061,694	1,043,681	
Secondary								**0.478**
Primary								**0.474**
Transmission								**0.469**
LS1	1.140%	0.38%	1,053,049	1,997	1,055,046	218,062	218,062	**0.484**
TOTAL *	100.00%	100.00%	92,372,719	522,109	92,894,828	19,174,072	19,143,079	**0.485**

* 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 100

DOCKET NO. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 7

Exhibit to the Testimony of James O. Vick

Exhibit (JOV-1)_____

Enclosed Documentation	Page
Plant Smith Consumptive Use Permit	1
NWFWMD correspondence to Gulf Power dated October 20, 2008	7
Federal Register Notice of Agency Information Collection Request dated July 2, 2009	8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 31
COMPANY Gulf Power Company (Direct)
WITNESS J. O. Vick (JOV-1)
DATE 11/02/09

Northwest Florida Water Management District

152 Water Management Drive, Havana, Florida 32333-4712
(U.S. Highway 90, 10 miles west of Tallahassee)
(850) 539-5999 (Fax) 539-2777

Douglas L. Hart
Executive Director

December 4, 2006

Gulf Power, Inc.
Lansing Smith Electric Generating Plant
One Energy Place
Pensacola, FL 32520-0328

NOTICE OF AGENCY ACTION
Individual Water Use Permit No. 19850073
Consumptive Use Permit Application No. 106771

Dear Permitee:

Your Individual Water Use Permit was approved by the Governing Board of the Northwest Florida Water Management District at a public hearing on November 30, 2006. The permit issued is subject to the terms and conditions set forth in the enclosed permit document. As you are legally responsible for compliance with the conditions of the permit please read the document thoroughly. Pay close attention to any condition(s) of the permit which require the one-time or periodic submittal of information to the District. Non-compliance may require the District to initiate enforcement action, including the possible assessment of administrative fines. Please designate an individual as the contact person for compliance. This can be done by sending the person's name, address, phone number and email address in hard-copy to the above address or via email (compliance@nwfwmd.state.fl.us).

If the property where the withdrawal facility is located changes ownership, the permit must be transferred. A permit transfer request must be made on NWFWMD Form A2-F (http://www.nwfwmd.state.fl.us/permits/forms/permit_transfer.pdf) and approved by the Executive Director. If the permit is not transferred you may remain responsible for compliance with the conditions of the permit.

If you have any questions concerning the permit document or if the District can be of any other service, please let us know.

Sincerely,

Angela Chelette, Chief
Bureau of Ground Water Regulation
Division of Resource Regulation

Enclosure
cc: Richard M. Markey

WAYNE BODIE, Chair, DeFuniak Springs
JOYCE ESTES, Vice Chair, Eastpoint
SHARON T. GASKIN, Secretary/Treasurer, Wewahitchka
PETER ANTONACCI, Tallahassee
STEPHANIE H. BLOYD, Panama City Beach
JERRY PATE, Tallahassee
PHILIP K. MCMILLAN, Blountstown
SHARON PINKERTON, Pensacola
GEORGE ROBERTS, Panama City

NORTHWEST FLORIDA WATER MANAGEMENT DISTRICT
INDIVIDUAL WATER USE PERMIT
(NWFWMD Form No. A2-E)

Permit granted to:

Gulf Power Company
Lansing Smith
Electric Generating Plant
One Energy Place
Pensacola, Florida 32520-0328
(Legal Name and Address)

Permit No.: 19850073 Renewal/Modification

Date Permit Granted: November 30, 2006

Permit Expires On: December 1, 2011

Source Classification: Floridan Aquifer, North Bay, Recycled Water

Use Classification: Power Generation
Public Supply
Industrial Uses

County: Bay Area: B

Location: Section ____ 1/4 Section ____

Application No.: 106771

Township 2 South Range 14, 15 West

Terms and standard conditions of this Permit are as follows:

1. That all statements in the application and in supporting data are true and accurate and based upon the best information available, and that all conditions set forth herein will be complied with. If any of the statements in the application and in the supporting data are found to be untrue and inaccurate, or if the Permittee fails to comply with all of the conditions set forth herein, then this Permit shall be revoked as provided by Chapter 373.243, Florida Statutes.

2. This Permit is predicated upon the assertion by the Permittee that the use of water applied for and granted is and continues to be a reasonable and beneficial use as defined in Section 373.019(4), Florida Statutes, is and continues to be consistent with the public interest, and will not interfere with any legal use of water existing on the date this Permit is granted.

3. This Permit is conditioned on the Permittee having obtained or obtaining all other necessary permit(s) to construct, operate and certify withdrawal facilities and the operation of water system.

4. This Permit is issued to the Permittee contingent upon continued ownership, lease or other present control of property rights in underlying, overlying, or adjacent lands. This Permit may be assigned to a subsequent owner as provided by Chapter 40A-2.351, Florida Administrative Code, and the acceptance by the transferee of all terms and conditions of the Permit.

19850073/106771

5. This Permit authorizes the Permittee to make a combined average annual withdrawal of **275,200,000*** gallons of water per day, a maximum combined withdrawal of **276,160,000**** gallons during a single day, and a combined monthly withdrawal of **8,531,200,000***** gallons. Withdrawals for the individual facilities are authorized as shown in the table below in paragraph six. However, the total combined amount of water withdrawn by all facilities listed in paragraph six shall not exceed the amounts identified above.

6. Individual Withdrawal Facility Authorization

WITHDRAWAL POINT ID NO.	LOCATION SEC,TWN,RNG	GALLONS/DAY AVERAGE	GALLONS/DAY MAXIMUM
LSGP #1 (AAA6592)	Sec. 36, T2S, R15W		720,000
LSGP #2 (AAA6591)	Sec. 36, T2S, R15W		720,000
LSGP #3 (AAA6590)	Sec. 36, T2S, R15W		Abandoned
LSGP #4 (AAD3491)	Sec. 25, T2S, R15W		720,000
LSGP #5 (AAE0186)	Sec. 19, T2S, R15W		720,000
LSGP #6 (To Be Assigned)	Sec. 17, T2S, R14W		720,000 Proposed
LGSP 1A/NB	Sec. 36, T2S, R15W		68,256,000
LGSP 1B/NB	Sec. 36, T2S, R15W		68,256,000
LGSP 2A/NB	Sec. 36, T2S, R15W		68,256,000
LGSP 2B/NB	Sec. 36, T2S, R15W		68,256,000
* 1,200,000 Ground Water - 274,000,000 Surface Water ** 2,160,000 Ground Water - 274,000,000 Surface Water *** 37,200,000 Ground Water - 8,494,000,000 Surface Water			

7. The use of the permitted water withdrawal is restricted to the use classification set forth by the Permit. Any change in the use of said water shall require a modification of this Permit.

8. The District's staff, upon proper identification, will have permission to enter, inspect and observe permitted and related facilities in order to determine compliance with the approved plans, specifications and conditions of this Permit.

9. The District's staff, upon providing prior notice and proper identification, may request permission to collect water samples for analysis, measure static and/or pumping water levels and collect any other information deemed necessary to protect the water resources of the area.

10. The District reserves the right, at a future date, to require the Permittee to submit pumpage records for any or all withdrawal point(s) covered by this Permit.

11. Permittee shall mitigate any significant adverse impact caused by withdrawals permitted herein on the resource and legal water withdrawals and uses, and on adjacent land use, which existed at the time of permit application. The District reserves the right to curtail permitted withdrawal rates if the withdrawal causes significant adverse impact on the resource and legal uses of water, or adjacent land use, which existed at the time of permit application.

12. Permittee shall not cause significant saline water intrusion or increased chloride levels. The District reserves the right to curtail permitted withdrawal rates if withdrawals cause significant saline water intrusion or increased chloride levels.

13. The District, pursuant to Section 373.042, Florida Statutes, at a future date, may establish minimum and/or management water levels in the aquifer, aquifers, or surface water hydrologically associated with the permitted withdrawals; these water levels may require the Permittee to limit withdrawal from these water sources at times when water levels are below established levels.

14. Nothing in this Permit should be construed to limit the authority of the Northwest Florida Water Management District to declare water shortages and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate and implement a plan during periods of water shortage pursuant to Section 373.246, Florida Statutes, or to declare Water Resource Caution Areas pursuant to Chapters 40A-2.801, and 62-40.41, Florida Administrative Code

    (a) In the event of a declared water shortage, water withdrawal reductions shall be made as ordered by the District.

    (b) In the event of a declared water shortage or an area as a Water Resource Caution Area, the District may alter, modify or inactivate all or parts of this permit.

15. The Permittee shall properly plug and abandon any well determined unsuitable for its intended use, not properly operated and maintained, or removed from service. The well(s) shall be plugged and abandoned to District Standards in accordance with Section 40A-3.531, Florida Administrative Code.

16. Any Specific Permit Condition(s) enumerated in Attachment A are herein made a part of this Permit.



Authorized Signature
Northwest Florida Water Management District

ATTACHMENT
Gulf Power Company
Lansing Smith Electric Generating Plant

Individual Water Use Permit No. 19850073
Individual Water Use Application No. 106771

1. The Permittee shall include the Individual Water Use Permit number and the well's Florida Unique Identification Number when submitting reports or otherwise corresponding with the District.

2. The Permittee shall not exceed ground water withdrawal amounts of an annual average daily amount of 1.2 million gallons, a maximum daily amount of 2.16 million gallons, and a maximum monthly amount of 37.2 million gallons.

3. The Permittee shall not exceed surface water withdrawal amounts of an annual average daily amount of 274 million gallons, a maximum daily amount of 274 million gallons and a maximum monthly amount of 8,494 million gallons.

4. The Permittee shall record the data required on the Water Use Summary Reporting Form, NWFWMD A2-I, and submit copies to the District by January 31 of each year. The withdrawals shall be reported separately by source (ground water, surface, and reclaimed). The ground and surface water withdrawals shall also be provided as an aggregate. The Permittee, if preferred, may submit the report electronically by downloading the correct form from the District website, filling it out properly, and e-mailing it to compliance@nwfwmd.state.fl.us. The next report is due January 31, 2007.

5. The Permittee, by January 31, April 30, July 31, and October 31 of each year, shall report the following information as specified below:

   a. Water quality results from tests conducted on each production well of the system during the first two weeks of the months of January, April, July, and October as appropriate to the reporting period. The water quality analysis shall test for the following chemical concentrations: chloride, sodium, sulfate, bicarbonate, carbonate, calcium, magnesium, potassium, and total dissolved solids. Prior to sampling, the Permittee shall purge approximately three to five well volumes from each well, and shall report with each set of test results, the duration of purging, purge volume, and purge rates used.

   b. Static water level data for each production well as recorded during the first two weeks of January, April, July, and October as appropriate to the reporting period. The water level data shall be referenced to mean sea level.

The next water use, water quality and water level reports are due by January 31, 2007.

19850073-106771

6. The Permittee shall continue to return approximately 95 percent or more of the surface water withdrawn.

7. The Permittee, at the time of construction, shall install an in-line totaling flow meter at the well head of proposed well LSGP #6. The Permittee shall maintain in working order in-line totaling flow meters on all other ground water wells.

8. The Permittee shall not exceed a withdrawal rate of 2,000 gallons per minute from the Floridan aquifer. The Permittee, at the time that LSGP #6 is operational, shall implement the pumping scenario identified in the ground water modeling analysis whereby LSGP #4, LSGP #5, and LSGP #6 are operated as primary wells and LSGP #1 and #2 are operated as backup and emergency supply wells.

9. The Permittee shall develop a plan to continue and expand implementation of water conservation and efficiency measures at the plant. The findings of the plan, along with a timetable for implementation, shall be submitted to the District no later than July 31, 2009.

10. The Permittee shall mitigate impacts attributable to the authorized withdrawal that interfere with users of water in the vicinity of Gulf Power's wells. The Permittee shall report the occurrence of any such impacts to the District and shall identify the mitigation action undertaken to address the impacts.

Douglas E. Barr
Executive Director

Northwest Florida Water Management District

152 Water Management Drive, Havana, Florida 32333-4712
(U.S. Highway 90, 10 miles west of Tallahassee)

(850) 539-5999 • (Fax) 539-2777

October 20, 2008

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328

RE: Individual Water Use Permit No. 19850073
Specific Condition No. 9

Dear Mr. Markey:

The District understands that Gulf Power is working to obtain reuse water as part of Gulf Power's water conservation effort in accordance with Specific Condition No. 9 of the Individual Water Use Permit. Obtaining and utilizing reuse water to directly reduce demand for ground water and surface water would result in a significant benefit to the water resources of the area. This activity clearly meets the intent of the permit condition. If I can provide any other information or endorsement in support of this effort, please contact me.

Sincerely,

Angela Chelette, P.G.
Chief, Bureau of Ground Water Regulation

GEORGE ROBERTS, Chair, Panama City
PHILIP K. McMILLAN, Vice Chair, Blountstown
SHARON PINKERTON, Secretary/Treasurer, Pensacola
PETER ANTONACCI, Tallahassee
STEPHANIE BLOYD, Panama City Beach
J. LUIS RODRIGUEZ, Monticello
STEVE GHAZVINI, Tallahassee
TIM NORRIS, Santa Rosa Beach
JERRY PATE, Pensacola

local and Tribal governments, the general public and international community to comment on the scope of the EIS, including identification of reasonable alternatives and specific issues to be addressed.

DOE will hold public scoping meetings from 5:30 p.m.–9:30 p.m. on the following dates and locations:

- July 21, 2009 Two Rivers Convention Center, 159 Main Street, Grand Junction, CO 81501.
- July 23, 2009 Embassy Suites Kansas City—Plaza, 220 West 43rd Street, Kansas City, MO 64111.
- July 28, 2009 Clarion Hotel and Conference Center, 1515 George Washington Way, Richland, WA 99352.
- July 30, 2009 North Augusta Municipal Center, 100 Georgia Avenue, North Augusta, SC 29841.
- August 4, 2009 El Capitan Resort, 540 F Street, Hawthorne, NV 89415.
- August 6, 2009 James Roberts Civic Center, 855 E. Broadway, Andrews, TX 79714.
- August 11, 2009 Shilo Inn/ O'Callahans Convention Center, 780 Lindsay Blvd., Idaho Falls, ID 83402.

Additional details on the scoping meetings will be provided in local media and at *http://www.mercurystorageeis.com.*

At each scoping meeting, DOE plans to hold an open house one hour prior to the formal portion of the meetings to allow participants to register to provide oral comments, view informational materials, and engage project staff. The registration table will have an oral comment registration form as well as a sign up sheet for those who do not wish to give oral comments but who would like to be included on the mailing list to receive future information. The public may provide written and/or oral comments at the scoping meetings.

Analysis of all public comments provided during the scoping meetings as well as those submitted as described in **ADDRESSES** above, will be considered in helping DOE further develop the scope of the EIS and potential issues to be addressed. DOE expects to issue a Draft EIS in the fall of 2009.

Issued in Washington, DC, on June 24, 2009.

Scott Blake Harris,

General Counsel.

[FR Doc. E9–15704 Filed 7–1–09; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Basic Energy Sciences Advisory Committee

AGENCY: Department of Energy, Office of Science.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Basic Energy Sciences Advisory Committee (BESAC). Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of these meetings be announced in the **Federal Register**.

DATES: Thursday, July 9, 2009, 8:30 a.m.–5:30 p.m., and Friday, July 10, 2009, 8:30 a.m. to 12 noon.

ADDRESSES: Bethesda North Marriott Hotel and Conference Center, 5701 Marinelli Road, North Bethesda, MD 20852.

FOR FURTHER INFORMATION CONTACT: Katie Perine; Office of Basic Energy Sciences; U. S. Department of Energy; Germantown Building, Independence Avenue, Washington, DC 20585; Telephone: (301) 903–6529.

SUPPLEMENTARY INFORMATION: *Purpose of the Meeting:* The purpose of this meeting is to provide advice and guidance with respect to the basic energy sciences research program.

Tentative Agenda: Agenda will include discussions of the following:

- News from Office of Science/DOE;
- News from the Office of Basic Energy Sciences;
- Report from the New Era Subcommittee's Photon Workshop;
- Energy Frontier Research Center Update;
- COV Report for Materials Science and Engineering Division;
- New BESAC Charge.

Public Participation: The meeting is open to the public. If you would like to file a written statement with the Committee, you may do so either before or after the meeting. If you would like to make oral statements regarding any of the items on the agenda, you should contact Katie Perine at 301–903–6594 (fax) or *katie.perine@science.doe.gov* (e-mail). Reasonable provision will be made to include the scheduled oral statements on the agenda. The Chairperson of the Committee will conduct the meeting to facilitate the orderly conduct of business. Public comment will follow the 10-minute rule. This notice is being published less than 15 days before the date of the meeting due to programmatic issues that had to be resolved.

Minutes: The minutes of this meeting will be available for public review and copying within 30 days at the Freedom of Information Public Reading Room; 1E–190, Forrestal Building; 1000 Independence Avenue, SW.; Washington, D.C. 20585; between 9 a.m. and 4 p.m., Monday through Friday, except holidays.

Issued in Washington, DC, on June 30, 2009.

Rachel M. Samuel,

Deputy Committee Management Officer.

[FR Doc. E9–15779 Filed 7–1–09; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2009–0234; FRL–8925–7]

Agency Information Collection Activities: Proposed Collection; Comment Request; Information Request for National Emission Standards for Coal- and Oil-fired Electric Utility Steam Generating Units; EPA ICR No. 2362.01

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this action announces that EPA is planning to submit a request for a new Information Collection Request (ICR) to the Office of Management and Budget (OMB). Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on the proposed information collection as described below.

DATES: Comments must be submitted on or before August 31, 2009.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2009–0234, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- E-mail: *a-and-r-docket@epa.gov.*
- Fax: (202) 566–1741.
- Mail: Air and Radiation Docket and Information Center, Environmental Protection Agency, Mailcode: 22821T, 1200 Pennsylvania Ave., NW., Washington, DC 20460.
- Hand Delivery: Air and Radiation Docket and Information Center, U.S. EPA, Room 3334, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2009–0234. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

FOR FURTHER INFORMATION CONTACT: William Maxwell, Energy Strategies Group, Sector Policies and Program Division, (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5430; fax number: (919) 541–5450; e-mail address: *maxwell.bill@epa.gov.*

SUPPLEMENTARY INFORMATION:

How Can I Access the Docket and/or Submit Comments?

EPA has established a public docket for this ICR under Docket ID No. EPA–HQ–OAR–2009–0234, which is available for online viewing at *www.regulations.gov*, or in-person viewing at the Air and Radiation Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The EPA/DC Public Reading Room is open from 8 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is 202–566–1744, and the telephone number for the Air and Radiation Docket is 202–566–1742.

Use *www.regulations.gov* to obtain a copy of the draft collection of information, submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the public docket that are available electronically. Once in the system, select "search," then key in the docket ID number identified in this document.

What Information Is EPA Particularly Interested in?

Pursuant to PRA section 3506(c)(2)(A), EPA specifically solicits comments and information to enable it to:

(i) Ealuate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(iii) enhance the quality, utility, and clarity of the information to be collected; and

(iv) minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.*, permitting electronic submission of responses).

What Should I Consider When I Prepare My Comments for EPA?

You may find the following suggestions helpful for preparing your comments.

1. Explain your views as clearly as possible and provide specific examples.
2. Describe any assumptions that you used.
3. Provide copies of any technical information and/or data you used that support your views.
4. If you estimate potential burden or costs, explain how you arrived at the estimate that you provide.
5. Offer alternative ways to improve the collection activity.
6. Make sure to submit your comments by the deadline identified under **DATES**.
7. To ensure proper receipt by EPA, be sure to identify the docket ID number assigned to this action in the subject line on the first page of your response. You may also provide the name, date, and **Federal Register** citation.

What Information Collection Activity or ICR Does This Apply to?

Affected entities: Entities potentially affected by this action are coal- and oil-fired electric utility steam generating units that emit hazardous air pollutants (HAP). Hazardous air pollutant means any pollutant listed pursuant to Clean Air Act (CAA) section 112(b). CAA section 112(a)(8) defines an electric utility steam generating unit as

> * * * any fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered a utility unit.

Title: Information Collection Effort for Coal- and Oil-fired Electric Utility Steam Generating Units.

ICR numbers: EPA ICR No. 2362.01.

ICR status: This ICR is for a new information collection activity. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, are displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: To obtain the information necessary to identify and categorize all coal- and oil-fired electric utility steam generating units potentially affected by the CAA section 112(d) standard, this ICR will solicit information from all potentially affected units under authority of CAA section 114. EPA intends to provide the survey in electronic format; however, written responses will also be accepted. The survey will be submitted to all facilities identified as being coal- or oil-fired electric utility steam generating units through databases available to the Agency. EPA envisions allowing recipients 3 months to respond to the survey. To further define the emission level being achieved by average of the top performing 12 percent of similar sources for the existing population, this ICR requires that certain units conduct emission testing concurrent with the survey. EPA envisions allowing recipients 6 months to respond to the emission testing requirement.

EPA estimates the cost of the information collection will be 100,370 hours and $104,807,458.

On December 20, 2000 (65 FR 79825, 79831), EPA added coal- and oil-fired electric utility steam generating units to the list of source categories under section 112(c). The CAA requires EPA to establish National Emission Standards for Hazardous Air Pollutants (NESHAP) for the control of HAP from both existing and new coal- and oil-fired electric utility steam generating units. Section 112(d) provides that for major sources, EPA must establish emission standards that reflect the maximum degree of reduction in emissions of HAP that is achievable, taking into consideration the cost of achieving the emission reduction, any non-air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the "maximum achievable control technology" (MACT). The minimum level of emission reduction that the MACT standards must achieve is known as the "MACT floor," as defined under CAA section 112(d)(3). The MACT floor for existing sources is the emission limitation achieved by the average of the best-performing 12 percent of existing sources in the category or subcategory. For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. For major sources, CAA section 112(d) also requires EPA to consider whether more stringent limits—known as beyond the floor standards—are achievable after taking into consideration the cost of achieving such emission reduction, any non-air health and environmental impacts, and energy impacts.

The Agency acquired unit-specific data and data on mercury from coal-fired units in an ICR approved on November 13, 1998 (OMB Control No. 2060–0396). These data were gathered in advance of the December 20, 2000 regulatory finding. These data sources are now over 10 years old and addressed only coal-fired electric utility steam generating units and only mercury emissions from such units. The Agency is aware that significant changes have been made in the intervening years in the number of operating coal- and oil-fired units, in industry ownership practices, and in emission control configurations. Further, in light of the statutory requirements for establishing emission standards under section 112(d) and the recent case law interpreting those requirements, the Agency believes that it needs additional data from both coal- and oil-fired electric utility steam generating units. We believe that obtaining updated information will be crucial to informing our decision on the NESHAP for coal- and oil-fired electric utility steam generating units.

The information in this ICR will be collected under authority of CAA section 114. CAA section 114(a) states, in pertinent part:

> For the purpose * * * (i) of * * * developing * * * any emission standard under section 7412 of this title * * * or (iii) carrying out any provision of this Chapter * * * (1) the Administrator may require any person who owns or operates any emission source * * * who the Administrator believes may have information necessary for the purposes set forth in this subsection * * * on a one-time, periodic or continuous basis to- * * * (B) make such reports * * *; (E) keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical * * *, and (G) provide such other information as the Administrator may reasonably require * * *

The data collected will be used to confirm the population of potentially affected coal- and oil-fired electric utility steam generating units, and update existing emission test data and fuel analysis information. These data will be used by the Agency to develop the NESHAP for coal- and oil-fired electric utility steam generating units under CAA section 112(d). Specifically, the data will provide the Agency with updated information on the number of potentially affected units, and available emission test data and fuel analysis data to address variability. All data collected will be added to existing emission test databases for coal- and oil-fired electric utility steam generating units; it will also be used to further evaluate the HAP emissions from these sources.

This collection of information is mandatory under CAA section 114 (42 U.S.C. 7414). All information submitted to EPA pursuant to this ICR for which a claim of confidentiality is made is safeguarded according to Agency policies in 40 CFR part 2, subpart B. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

The EPA would like to solicit comments to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the methodology and assumptions used;

(iii) Enhance the quality, utility, and clarity of the information to be collected; and

(iv) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.*, permitting electronic submission of responses).

Burden Statement: The projected cost and hour burden for this one-time collection of information is $104,807,458 and 100,370 hours. This burden is based on an estimated 555 facilities (1,325 units) being respondents to the survey and required emission testing. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

The ICR provides a detailed explanation of the Agency's estimate, which is only briefly summarized here.

Estimated total number of potential respondents: 555 facilities (1,325 units).

Frequency of response: One time.

Estimated total average number of responses for each respondent: 1.

Estimated total annual burden hours: 100,370.

Estimated total annual burden costs: $104,807,458.

What Is the Next Step in the Process for This ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. At that time, EPA will issue another **Federal Register** notice pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the

technical person listed under FOR FURTHER INFORMATION CONTACT.

Dated: June 26, 2009.

Mary E. Henigin,

Acting Director, Sector Policies and Programs Division.

[FR Doc. E9-15686 Filed 7-1-09; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

[EPA-HQ-OECA-2008-0369; FRL-8925-4]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; NESHAP for Clay Ceramics Manufacturing (Renewal), EPA ICR Number 2023.04, OMB Control Number 2060-0513

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this document announces that an Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval. This is a request to renew an existing approved collection. The ICR, which is abstracted below, describes the nature of the collection and the estimated burden and cost.

DATES: Additional comments may be submitted on or before August 3, 2009.

ADDRESSES: Submit your comments, referencing docket ID number EPA-OECA-2008-0369, to (1) EPA online using *http://www.regulations.gov* (our preferred method), or by e-mail to *docket.oeca@epa.gov*, or by mail to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Enforcement and Compliance Docket and Information Center, mail code 28221T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, and (2) OMB at: Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attention: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Sounjay Gairola, Office of Enforcement and Compliance Assurance, Mail Code 2242A, Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: (202) 564-4003; e-mail address: *gairola.sounjay@epa.gov*.

SUPPLEMENTARY INFORMATION: EPA has submitted the following ICR to OMB for review and approval according to the procedures prescribed in 5 CFR 1320.12. On May 30, 2008 (73 FR 31088), EPA sought comments on this ICR pursuant to 5 CFR 1320.8(d). EPA received no comments. Any additional comments on this ICR should be submitted to EPA and OMB within 30 days of this notice.

EPA has established a public docket for this ICR under docket ID number EPA-HQ-OECA-2008-0369, which is available for public viewing online at *http://www.regulations.gov*, in person viewing at the Enforcement and Compliance Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The EPA Docket Center 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 Reading Room is (202) 566-1744, and the telephone number for the Enforcement and Compliance Docket is (202) 566-1752.

Use EPA's electronic docket and comment system at *http://www.regulations.gov*, to submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the docket that are available electronically. Once in the system, select "docket search," then key in the docket ID number identified above. Please note that EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing at *http://www.regulations.gov*, as EPA receives them and without change, unless the comment contains copyrighted material, Confidential Business Information (CBI), or other information whose public disclosure is restricted by statute. For further information about the electronic docket, go to *http://www.regulations.gov*.

Title: NESHAP for Clay Ceramics Manufacturing (Renewal).

ICR Numbers: EPA ICR Number 2023.04, OMB Control Number 2060-0513.

ICR Status: This ICR is scheduled to expire on August 31, 2009. Under OMB regulations, the Agency may continue to conduct or sponsor the collection of information while this submission is pending at OMB. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, and displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: The National Emission Standards for Hazardous Air Pollutants (NESHAP) for Clay Ceramics Manufacturing (40 CFR part 63, subpart KKKKK) were proposed on July 22, 2002 (67 FR 47893) and promulgated on May 16, 2003 (67 FR 26738).

The affected entities are subject to the General Provisions of the NESHAP at 40 CFR part 63, subpart A, and any changes, or additions to the General Provisions specified at 40 CFR part 63, subpart KKKKK.

Owners or operators of the affected facilities must submit a one-time-only report of any physical or operational changes, initial performance tests, and periodic reports and results. Owners or operators are also required to maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility, or any period during which the monitoring system is inoperative. Reports, at a minimum, are required semiannually.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 17 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Respondents/Affected Entities: Clay ceramics manufacturing facilities.

Estimated Number of Respondents: 10.

Frequency of Response: Initially, occasionally, and semiannually.

Estimated Total Annual Hour Burden: 527.

Estimated Total Annual Cost: $45,702, which includes labor costs of $42,532, O&M costs of $2,468, and annualized capital/startup costs of $702.

Changes in the Estimates: There is no change in the total estimated burden

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

Line		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2008 - December 2008 (Schedule 2A, Line 5 + 6)	(1,428,879)
2	Estimated/Actual True-Up Amount approved for the period January 2008 - December 2008 (FPSC Order No. PSC-08-0775-FOF-EI)	(2,810,290)
3	Final True-Up Amount to be refunded/(recovered) in the in the projection period January 2010 - December 2010 (Lines 1 - 2)	1,381,411

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 32
COMPANY Gulf Power Company (Direct)
WITNESS R. W. Dodd (RWD-1)
DATE 11/02/09

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 1 of 38

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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)	4,058,103	3,422,308	3,346,536	3,480,637	4,329,372	4,831,384	5,305,640	4,867,102	4,656,354	3,769,208	3,472,081	4,439,433	49,978,158
2	True-Up Provision (Order No PSC-07-0922-FOF-EI)	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,704	140,459
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	4,069,808	3,434,013	3,358,241	3,492,342	4,341,077	4,843,089	5,317,345	4,878,807	4,668,059	3,780,913	3,483,786	4,451,137	50,118,617
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5A, Line 9)	1,193,539	1,711,847	905,878	1,280,921	930,661	1,519,145	1,317,052	1,012,236	1,397,131	814,418	857,324	1,089,175	14,029,327
	b Capital Investment Projects (Schedule 7A, Line 9)	2,878,246	2,907,557	2,946,619	3,072,904	3,180,615	3,206,613	3,221,888	3,217,077	3,223,763	3,218,907	3,214,160	3,238,909	37,527,258
	c **Total Jurisdictional ECRC Costs**	4,071,785	4,619,404	3,852,497	4,353,825	4,111,276	4,725,758	4,538,940	4,229,313	4,620,894	4,033,325	4,071,484	4,328,084	51,556,585
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	(1,977)	(1,185,391)	(494,256)	(861,483)	229,801	117,331	778,405	649,494	47,165	(252,412)	(587,698)	123,053	(1,437,968)
6	Interest Provision (Schedule 3A, Line 10)	5,387	2,577	369	(1,217)	(1,895)	(1,429)	(546)	884	2,377	2,170	425	(12)	9,089
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2007	(647,455)	(655,750)	(1,850,269)	(2,355,861)	(3,230,266)	(3,014,065)	(2,909,868)	(2,143,714)	(1,505,042)	(1,467,204)	(1,729,152)	(2,328,130)	(647,455)
	b Final True-Up from January 2006 - December 2006 (Order No PSC-07-0922-FOF-EI)	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385
8	True-Up Collected/(Refunded) (see Line 2)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,704)	(140,459)
9	Adjustments													
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	1,602,635	408,116	(97,476)	(971,881)	(755,680)	(651,483)	114,671	753,343	791,181	529,233	(69,745)	41,592	41,592

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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 2A, Lines 7a + 7b)	1,610,930	1,602,635	408,116	(97,476)	(971,881)	(755,680)	(651,483)	114,671	753,343	791,181	529,233	(69,745)	
2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8)	1,597,248	405,539	(97,845)	(970,664)	(753,785)	(650,054)	115,217	752,460	788,803	527,064	(70,170)	41,604	
3 *Total of Beginning & Ending True-up (Lines 1 + 2)*	3,208,178	2,008,173	310,271	(1,068,140)	(1,725,666)	(1,405,734)	(536,266)	867,131	1,542,147	1,318,244	459,064	(28,141)	
4 Average True-Up Amount (Line 3 x 1/2)	1,604,089	1,004,087	155,136	(534,070)	(862,833)	(702,867)	(268,133)	433,565	771,073	659,122	229,532	(14,070)	
5 Interest Rate (First Day of Reporting Business Month)	0 049800	0 030800	0 030800	0 026300	0.028400	0.024300	0.024500	0.024400	0.024500	0.049500	0 029500	0 014900	
6 Interest Rate (First Day of Subsequent Business Month)	0.030800	0.030800	0.026300	0.028400	0.024300	0.024500	0.024400	0.024500	0.049500	0.029500	0.014900	0.005400	
7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.080600	0.061600	0.057100	0.054700	0.052700	0.048800	0.048900	0.048900	0.074000	0.079000	0.044400	0.020300	
8 *Average Interest Rate (Line 7 x 1/2)*	*0.040300*	*0 030800*	*0 028550*	*0 027350*	*0.026350*	*0.024400*	*0.024450*	*0 024450*	*0.037000*	*0 039500*	*0 022200*	*0 010150*	
9 Monthly Average Interest Rate (Line 8 x 1/12)	0.003358	0.002567	0.002379	0.002279	0.002196	0.002033	0.002038	0.002038	0.003083	0.003292	0.001850	0.000846	
10 Interest Provision for the Month (Line 4 x Line 9)	5,387	2,577	369	(1,217)	(1,895)	(1,429)	(546)	884	2,377	2,170	425	(12)	9,089

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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	824,122	824,622	(500)	(0.1) %
	.3 Title V	102,830	98,173	4,657	4.7 %
	.4 Asbestos Fees	300	2,184	(1,884)	(86.3) %
	.5 Emission Monitoring	509,981	530,117	(20,136)	(3.8) %
	.6 General Water Quality	408,499	366,108	42,391	11.6 %
	.7 Groundwater Contamination Investigation	1,494,099	1,504,437	(10,338)	(0.7) %
	.8 State NPDES Administration	42,000	42,000	0	0.0 %
	9 Lead and Copper Rule	20,890	21,348	(458)	(2.1) %
	.10 Env Auditing/Assessment	18,847	6,700	12,147	181.3 %
	.11 General Solid & Hazardous Waste	428,048	373,491	54,557	14.6 %
	.12 Above Ground Storage Tanks	106,811	177,549	(70,738)	(39.8) %
	.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	207,299	247,939	(40,640)	(16.4) %
	.17 Gulf Coast Ozone Study	0	0	0	0.0 %
	.18 SPCC Substation Project	68,945	0	68,945	0.0 %
	.19 FDEP NOX Reduction Agreement	3,639,883	3,713,809	(73,926)	(2.0) %
	.20 CAIR/CAMR/CAVR Compliance Program	583,406	473,267	110,139	23.3 %
	.21 Mercury Allowances	0	0	0	0.0 %
	22 Annual NOx Allowances	0	0	0	0.0 %
	.23 Seasonal NOx Allowances	0	0	0	0.0 %
	.24 SO2 Allowances	6,047,510	6,835,142	(787,632)	(11.5) %
2	Total O & M Activities	14,503,470	15,216,886	(713,416)	(4.7) %
3	Recoverable Costs Allocated to Energy	11,915,031	12,723,069	(808,038)	(6.4) %
4	Recoverable Costs Allocated to Demand	2,588,439	2,493,817	94,622	3.8 %

Notes:

Column (1) is the End of Period Totals on Schedule 5A
Column (2) contains the approved Estimated/Actual amounts in accordance with FPSC Order No. PSC-08-0775-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 2008 - December 2008

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	-	700,225	23	-	-	-	-	-	-	-	-	123,874	824,122	0	824,122
	3 Title V	8,180	9,382	8,735	7,963	6,200	8,317	9,668	8,906	9,299	8,686	8,365	9,129	102,830	0	102,830
	4 Asbestos Fees	1,500	-	300	(1,537)	(79)	-	-	-	-	300	-	(184)	300	300	0
	5 Emission Monitoring	30,700	31,550	59,328	39,967	43,127	40,897	23,046	47,554	36,120	40,971	43,706	73,015	509,981	0	509,981
	6 General Water Quality	9,714	25,580	12,045	15,198	28,455	47,583	40,869	39,012	77,796	46,332	42,477	23,438	408,499	408,499	0
	7 Groundwater Contamination Investigation	(6,161)	64,126	84,006	62,604	122,829	561,836	179,514	33,258	253,815	59,367	41,162	37,743	1,494,099	1,494,099	0
	8 State NPDES Administration	-	-	-	-	-	-	-	-	-	-	7,500	34,500	42,000	42,000	0
	9 Lead and Copper Rule	3,583	-	3,036	-	547	3,382	-	3,974	300	6,068	-	-	20,890	20,890	0
	10 Env Auditing/Assessment	-	-	3,909	377	414	-	10,302	2,808	21	-	215	801	18,847	18,847	0
	11 General Solid & Hazardous Waste	19,751	15,681	55,590	30,230	36,632	35,756	71,588	33,756	16,933	38,192	17,134	56,805	428,048	428,048	0
	12 Above Ground Storage Tanks	(7,688)	7,188	35,683	24,143	(7,078)	5,491	25,468	341	1,127	-	19,697	2,439	106,811	106,811	0
	13 Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	16 Sodium Injection	18,013	18,068	5,376	24,848	17,380	29,554	7,314	14,571	22,607	7,844	7,457	34,267	207,299	0	207,299
	17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	14,155	54,790	68,945	0	68,945
	19 FDEP NOX Reduction Agreement	596,519	389,227	169,915	438,599	207,430	258,005	303,745	215,627	281,206	250,847	305,751	223,012	3,639,883	0	3,639,883
	20 CAIR/CAMR/CAVR Compliance Program	-	-	-	169,999	55,534	(10,665)	19,182	20,261	197,080	21,529	19,557	90,929	583,406	0	583,406
	21 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	22 Annual NOx Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	23 Seasonal NOx Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	24 SO2 Allowances	563,792	510,454	499,179	509,587	449,566	590,490	668,732	624,613	545,756	361,070	359,941	364,330	6,047,510	0	6,047,510
2	Total of O & M Activities	1,237,903	1,771,481	937,125	1,321,978	960,957	1,570,646	1,359,428	1,044,681	1,442,060	841,206	887,117	1,128,888	14,503,470	2,519,494	11,983,976
3	Recoverable Costs Allocated to Energy	1,217,204	1,658,906	742,556	1,190,963	779,237	916,598	1,031,687	931,532	1,092,068	690,947	744,777	918,556	11,915,031		
4	Recoverable Costs Allocated to Demand	20,699	112,575	194,569	131,015	181,720	654,048	327,741	113,149	349,992	150,259	142,340	210,332	2,588,439		
5	Retail Energy Jurisdictional Factor	0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (A)	1,173,581	1,603,301	718,271	1,154,594	755,444	888,501	1,001,039	903,136	1,059,663	669,536	720,077	886,370	11,533,513		
8	Jurisdictional Demand Recoverable Costs (B)	19,958	108,546	187,607	126,327	175,217	630,644	316,013	109,100	337,468	144,882	137,247	202,805	2,495,814		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,193,539	1,711,847	905,878	1,280,921	930,661	1,519,145	1,317,052	1,012,236	1,397,131	814,418	857,324	1,089,175	14,029,327		

Notes:
(A) Line 3 x Line 5 x 1.0007 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 2008 - December 2008

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	46,339	46,344	(5)	(0.0)	%
2	Crist 5, 6 & 7 Precipitator Projects	1,942,918	1,951,133	(8,215)	(0.4)	%
.3	Crist 7 Flue Gas Conditioning	168,690	168,693	(3)	(0.0)	%
.4	Low NOx Burners, Crist 6 & 7	2,052,286	2,052,284	2	0.0	%
5	CEMS - Plants Crist, Scholz, Smith, & Daniel	820,797	832,135	(11,338)	(1.4)	%
.6	Sub Contam. Mobile Groundwater Treat Sys	104,419	104,412	7	0.0	%
7	Raw Water Well Flowmeters - Plants Crist & Smith	27,821	27,825	(4)	(0.0)	%
8	Crist Cooling Tower Cell	59,390	59,391	(1)	(0.0)	%
9	Crist 1-5 Dechlorination	28,377	28,374	3	0.0	%
.10	Crist Diesel Fuel Oil Remediation	7,119	7,121	(2)	(0.0)	%
11	Crist Bulk Tanker Unload Sec Contain Struc	9,442	9,446	(4)	(0.0)	%
12	Crist IWW Sampling System	5,502	5,502	0	0.0	%
13	Sodium Injection System	49,924	49,923	1	0.0	%
14	Smith Stormwater Collection System	259,100	259,098	2	0.0	%
15	Smith Waste Water Treatment Facility	36,307	36,309	(2)	(0.0)	%
16	Daniel Ash Management Project	2,113,885	2,113,083	802	0.0	%
.17	Smith Water Conservation	16,627	16,633	(6)	(0.0)	%
18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	18,239,305	18,263,765	(24,460)	(0.1)	%
20	Crist Stormwater Collection System	128,439	128,437	2	0.0	%
21	Crist Common FTIR Monitor	8,122	8,126	(4)	(0.0)	%
22	Precipitator Upgrades for CAM Compliance	3,839,369	3,835,676	3,693	0.1	%
23	Plant Groundwater Investigation	0	0	0	0.0	%
24	Crist Water Conservation	13,435	13,086	349	2.7	%
25	Crist Condenser Tubes	811,688	808,517	3,171	0.4	%
26	CAIR/CAMR/CAVR Compliance	6,859,590	7,056,845	(197,255)	(2.8)	%
27	General Water Quality	7,140	7,137	3	0.0	%
28	Mercury Allowances	0	0	0	0.0	%
29	Annual Nox Allowances	0	0	0	0.0	%
30	Seasonal Nox Allowances	0	0	0	0.0	%
31	SO2 Allowances	1,119,632	1,101,320	18,312	1.7	%
2	Total Investment Projects - Recoverable Costs	38,775,663	38,990,615	(214,952)	(0.6)	%
3	Recoverable Costs Allocated to Energy	35,426,104	35,651,631	(225,527)	(0.6)	%
4	Recoverable Costs Allocated to Demand	3,349,559	3,338,984	10,575	0.3	%

Notes:
Column (1) is the End of Period Totals on Schedule 7A
Column (2) contains the approved Estimated/Actual amounts in accordance with FPSC Order No PSC-08-0775-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 2008 - December 2008

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	3,998	3,973	3,948	3,923	3,899	3,874	3,849	3,824	3,800	3,775	3,750	3,726	46,339	0	46,339
	2 Crist 5, 6 & 7 Precipitator Projects	164,510	164,039	163,565	163,093	162,619	162,148	161,672	161,201	160,726	160,255	159,781	159,309	1,942,918	0	1,942,918
	3 Crist 7 Flue Gas Conditioning	14,068	14,067	14,064	14,062	14,060	14,059	14,057	14,054	14,053	14,051	14,049	14,046	168,690	0	168,690
	4 Low NOx Burners, Crist 6 & 7	172,282	172,054	171,824	171,596	171,367	171,138	170,910	170,680	170,451	170,223	169,994	169,767	2,052,286	0	2,052,286
	5 CEMS - Plants Crist, Scholz, Smith & Daniel	64,247	64,141	64,032	65,227	66,422	71,502	73,484	70,207	70,057	70,057	70,190	71,231	820,797	0	820,797
	.6 Sub Contam Mobile Groundwater Treat Sys	8,795	8,779	8,762	8,745	8,727	8,712	8,693	8,676	8,659	8,642	8,623	8,606	104,419	96,387	8,032
	7 Raw Water Well Flowmeters - Plants Crist & Smith	2,349	2,343	2,339	2,333	2,327	2,322	2,316	2,310	2,303	2,300	2,293	2,286	27,821	25,680	2,141
	8 Crist Cooling Tower Cell	4,970	4,950	4,956	4,953	4,950	4,949	4,948	4,946	4,944	4,943	4,941	4,940	59,390	54,822	4,568
	9 Crist 1-5 Dechlorination	2,406	2,399	2,392	2,383	2,376	2,369	2,360	2,353	2,347	2,338	2,330	2,324	28,377	26,193	2,184
	10 Crist Diesel Fuel Oil Remediation	603	601	600	598	596	595	592	591	589	586	586	582	7,119	6,572	547
	11 Crist Bulk Tanker Unload Sec Contain Struc	801	799	795	794	791	787	786	783	780	778	776	772	9,442	8,716	726
	12 Crist IWW Sampling System	467	466	464	462	461	459	458	457	455	452	452	449	5,502	5,078	424
	13 Sodium Injection System	4,212	4,202	4,192	4,184	4,174	4,166	4,155	4,148	4,137	4,126	4,119	4,109	49,924	0	49,924
	14 Smith Stormwater Collection System	21,892	21,838	21,783	21,729	21,673	21,618	21,564	21,509	21,455	21,401	21,346	21,292	259,100	239,169	19,931
	15 Smith Waste Water Treatment Facility	3,045	3,042	3,037	3,033	3,031	3,026	3,024	3,020	3,017	3,014	3,011	3,007	36,307	33,517	2,790
	16 Daniel Ash Management Project	178,747	178,270	177,792	177,305	176,813	176,325	175,887	175,443	174,985	174,562	174,112	173,644	2,113,885	1,951,277	162,608
	17 Smith Water Conservation	1,400	1,397	1,395	1,392	1,390	1,387	1,386	1,380	1,379	1,376	1,374	1,371	16,627	15,348	1,279
	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	1,534,268	1,533,932	1,533,514	1,529,852	1,526,182	1,522,534	1,518,877	1,515,200	1,511,546	1,507,877	1,503,984	1,501,539	18,239,305	0	18,239,305
	20 Crist Stormwater Collection System	10,830	10,807	10,784	10,762	10,738	10,715	10,691	10,669	10,645	10,622	10,600	10,576	128,439	118,559	9,880
	21 Crist Common FTIR Monitor	686	684	682	682	679	677	676	675	672	671	670	668	8,122	0	8,122
	22 Precipitator Upgrades for CAM Compliance	232,460	258,161	298,220	330,809	338,911	340,676	340,689	340,622	340,622	340,139	339,345	338,715	3,839,369	0	3,839,369
	23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	24 Crist Water Conservation	1,104	1,101	1,099	1,096	1,094	1,091	1,090	1,087	1,085	1,082	1,080	1,426	13,435	12,401	1,034
	25 Crist Condenser Tubes	67,521	67,373	67,228	67,079	66,934	66,853	69,278	69,585	67,443	67,385	67,461	67,550	811,688	749,249	62,439
	26 CAIR/CAMR/CAVR Compliance	365,808	370,958	375,761	475,969	589,483	621,643	640,934	652,723	669,856	678,750	689,889	727,816	6,859,590	0	6,859,590
	27 General Water Quality	615	611	608	605	601	597	593	590	585	582	578	575	7,140	6,591	549
	28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	29 Annual Nox Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	30 Seasonal Nox Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	31 SO2 Allowances	123,134	118,067	113,304	108,546	102,006	95,266	89,317	83,025	77,505	73,227	69,826	66,409	1,119,632	0	1,119,632
2	Total Investment Projects - Recoverable Costs	2,985,218	3,009,054	3,047,140	3,171,212	3,282,304	3,309,488	3,322,286	3,319,758	3,324,094	3,323,214	3,325,160	3,356,735	38,775,663	3,349,559	35,426,104
3	Recoverable Costs Allocated to Energy	2,703,176	2,727,724	2,766,495	2,891,270	3,003,071	3,030,897	3,041,981	3,039,698	3,046,553	3,046,233	3,048,638	3,080,368	35,426,104		
4	Recoverable Costs Allocated to Demand	282,042	281,330	280,645	279,942	279,233	278,591	280,305	280,060	277,541	276,981	276,522	276,367	3,349,559		
5	Retail Energy Jurisdictional Factor	0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (B)	2,606,297	2,636,294	2,676,017	2,802,979	2,911,374	2,937,991	2,951,613	2,947,039	2,956,154	2,951,837	2,947,533	2,972,432	34,297,560		
8	Jurisdictional Demand Recoverable Costs (C)	271,949	271,263	270,602	269,925	269,241	268,627	270,275	270,038	267,609	267,070	266,627	266,477	3,229,698		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	2,878,246	2,907,557	2,946,619	3,072,904	3,180,615	3,206,613	3,221,888	3,217,077	3,223,763	3,218,907	3,214,160	3,238,909	37,527,258		

Notes:

(A) Pages 1-27 of Schedule 8A Line 9 Pages 28-31 of Schedule 8A, Line 6
(B) Line 3 x Line 5 x 1.0007 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 2008 - December 2008

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)	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	
3	Less: Accumulated Depreciation (C)	(73,211)	(75,834)	(78,456)	(81,079)	(83,701)	(86,324)	(88,946)	(91,569)	(94,191)	(96,814)	(99,436)	(102,059)	(104,682)	
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)	147,083	144,460	141,838	139,215	136,593	133,970	131,348	128,725	126,103	123,480	120,858	118,235	115,612	
6	Average Net Investment		145,772	143,149	140,527	137,904	135,282	132,659	130,037	127,414	124,792	122,169	119,547	116,924	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,071	1,052	1,032	1,013	994	975	955	936	917	898	878	859	11,580
	b Debt Component (Line 6 x Debt Component x 1/12)		304	299	293	288	282	277	271	266	260	255	249	244	3,288
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		2,623	2,622	2,623	2,622	2,623	2,622	2,623	2,622	2,623	2,622	2,623	2,623	31,471
	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)		3,998	3,973	3,948	3,923	3,899	3,874	3,849	3,824	3,800	3,775	3,750	3,726	46,339
	a Recoverable Costs Allocated to Energy		3,998	3,973	3,948	3,923	3,899	3,874	3,849	3,824	3,800	3,775	3,750	3,726	46,339
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,855	3,840	3,819	3,803	3,780	3,755	3,735	3,707	3,687	3,658	3,626	3,595	44,860
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	3,840	3,819	3,803	3,780	3,755	3,735	3,707	3,687	3,658	3,626	3,595	44,860

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 2008 - December 2008

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		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)	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	
3	Less: Accumulated Depreciation (C)	(2,382,642)	(2,432,772)	(2,482,904)	(2,533,034)	(2,583,166)	(2,633,297)	(2,683,429)	(2,733,560)	(2,783,692)	(2,833,823)	(2,883,955)	(2,934,087)	(2,984,219)	
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)	12,149,236	12,099,106	12,048,974	11,998,844	11,948,712	11,898,581	11,848,449	11,798,318	11,748,186	11,698,055	11,647,923	11,597,791	11,547,659	
6	Average Net Investment		12,124,171	12,074,040	12,023,909	11,973,778	11,923,647	11,873,515	11,823,384	11,773,252	11,723,121	11,672,989	11,622,857	11,572,725	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		89,077	88,708	88,340	87,972	87,603	87,235	86,866	86,499	86,130	85,761	85,393	85,025	1,044,609
	b Debt Component (Line 6 x Debt Component x 1/12)		25,303	25,199	25,095	24,989	24,885	24,781	24,675	24,570	24,465	24,362	24,256	24,152	296,732
8	Investment Expenses														
	a Depreciation (E)		38,756	38,756	38,756	38,756	38,757	38,756	38,757	38,756	38,757	38,756	38,758	38,758	465,079
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		11,374	11,376	11,374	11,376	11,374	11,376	11,374	11,376	11,374	11,376	11,374	11,374	136,498
	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)		164,510	164,039	163,565	163,093	162,619	162,148	161,672	161,201	160,726	160,255	159,781	159,309	1,942,918
	a Recoverable Costs Allocated to Energy		164,510	164,039	163,565	163,093	162,619	162,148	161,672	161,201	160,726	160,255	159,781	159,309	1,942,918
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		158,614	158,541	158,216	158,114	157,654	157,178	156,869	156,287	155,957	155,289	154,482	153,727	1,880,928
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)		158,614	158,541	158,216	158,114	157,654	157,178	156,869	156,287	155,957	155,289	154,482	153,727	1,880,928

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) 3.2% 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 2008 - December 2008

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)	1,469,714	1,469,510	1,469,306	1,469,102	1,468,899	1,468,695	1,468,491	1,468,287	1,468,084	1,467,880	1,467,676	1,467,472	1,467,269	
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)	1,469,714	1,469,510	1,469,306	1,469,102	1,468,899	1,468,695	1,468,491	1,468,287	1,468,084	1,467,880	1,467,676	1,467,472	1,467,269	
6	Average Net Investment		1,469,612	1,469,408	1,469,204	1,469,001	1,468,797	1,468,593	1,468,389	1,468,186	1,467,982	1,467,778	1,467,574	1,467,371	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,797	10,796	10,794	10,793	10,791	10,790	10,788	10,787	10,785	10,784	10,782	10,781	129,468
	b Debt Component (Line 6 x Debt Component x 1/12)		3,067	3,067	3,066	3,066	3,065	3,065	3,065	3,064	3,064	3,063	3,063	3,062	36,777
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		204	204	204	203	204	204	204	203	204	204	204	203	2,445
	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)		14,068	14,067	14,064	14,062	14,060	14,059	14,057	14,054	14,053	14,051	14,049	14,046	168,690
	a Recoverable Costs Allocated to Energy		14,068	14,067	14,064	14,062	14,060	14,059	14,057	14,054	14,053	14,051	14,049	14,046	168,690
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,564	13,595	13,604	13,633	13,631	13,628	13,639	13,626	13,636	13,616	13,583	13,554	163,309
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)		13,564	13,595	13,604	13,633	13,631	13,628	13,639	13,626	13,636	13,616	13,583	13,554	163,309

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) 3.2% 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 2008 - December 2008

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)	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	
3	Less: Accumulated Depreciation (C)	6,604,116	6,579,852	6,555,588	6,531,324	6,507,060	6,482,796	6,458,532	6,434,268	6,410,004	6,385,740	6,361,476	6,337,211	6,312,945	
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)	15,702,039	15,677,775	15,653,511	15,629,247	15,604,983	15,580,719	15,556,455	15,532,191	15,507,927	15,483,663	15,459,399	15,435,134	15,410,868	
6	Average Net Investment		15,689,907	15,665,643	15,641,379	15,617,115	15,592,851	15,568,587	15,544,323	15,520,059	15,495,795	15,471,531	15,447,267	15,423,001	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		115,274	115,095	114,917	114,739	114,561	114,382	114,204	114,026	113,847	113,670	113,490	113,313	1,371,518
	b Debt Component (Line 6 x Debt Component x 1/12)		32,744	32,695	32,643	32,593	32,542	32,492	32,442	32,390	32,340	32,289	32,239	32,188	389,597
8	Investment Expenses														
	a Depreciation (E)		24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,265	24,266	291,171
	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)		172,282	172,054	171,824	171,596	171,367	171,138	170,910	170,680	170,451	170,223	169,994	169,767	2,052,286
	a Recoverable Costs Allocated to Energy		172,282	172,054	171,824	171,596	171,367	171,138	170,910	170,680	170,451	170,223	169,994	169,767	2,052,286
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0 9634865	0 9658052	0 9666186	0 9687846	0.9687876	0 9686688	0.9696144	0 9688390	0 9696486	0 9683344	0 9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0 9642160	0.9642160	0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	0.9642160	0.9642160	0 9642160	0 9642160	
12	Retail Energy-Related Recoverable Costs (H)		166,108	166,287	166,205	166,356	166,134	165,892	165,833	165,477	165,393	164,948	164,356	163,818	1,986,807
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)		166,108	166,287	166,205	166,356	166,134	165,892	165,833	165,477	165,393	164,948	164,356	163,818	1,986,807

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 2% 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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1154, 1164, 1217, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 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		0	0	0	277,167	443	1,098,159	(745,439)	28,912	9,022	14,100	39,569	67,919	
	b Clearings to Plant		0	0	0	0	0	0	252,857	29,239	4,099	(1,728)	0	692,586	
	c Retirements		0	0	0	0	0	0	0	157,729	0	0	0	70,000	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	764	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,551,335	4,422,845	4,426,944	4,425,216	4,425,216	5,047,802	
3	Less: Accumulated Depreciation (C)	949,689	937,922	926,149	914,377	902,604	890,837	879,060	866,849	1,012,146	999,932	987,712	975,495	1,033,395	
4	CWIP - Non Interest Bearing	187,201	187,201	187,201	187,201	464,368	464,811	1,562,970	564,674	564,347	569,270	585,098	624,667	0	
5	Net Investment (Lines 2 + 3 + 4)	5,435,368	5,423,601	5,411,828	5,400,056	5,665,450	5,654,126	6,740,508	5,982,858	5,999,338	5,996,146	5,998,026	6,025,378	6,081,197	
6	Average Net Investment		5,429,484	5,417,714	5,405,942	5,532,753	5,659,788	6,197,317	6,361,683	5,991,098	5,997,742	5,997,086	6,011,702	6,053,287	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		39,892	39,802	39,718	40,647	41,585	45,531	46,740	44,015	44,066	44,061	44,168	44,474	514,699
	b Debt Component (Line 6 x Debt Component x 1/12)		11,329	11,307	11,283	11,548	11,811	12,935	13,274	12,501	12,518	12,517	12,546	12,634	146,203
8	Investment Expenses														
	a Depreciation (E)		11,635	11,641	11,640	11,641	11,635	11,645	12,079	12,300	12,082	12,088	12,085	12,732	143,203
	b Amortization (F)		132	132	132	132	132	132	132	132	132	132	132	132	1,584
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	15,108
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		64,247	64,141	64,032	65,227	66,422	71,502	73,484	70,207	70,057	70,057	70,190	71,231	820,797
	a Recoverable Costs Allocated to Energy		64,247	64,141	64,032	65,227	66,422	71,502	73,484	70,207	70,057	70,057	70,190	71,231	820,797
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		61,944	61,991	61,938	63,235	64,394	69,310	71,301	68,067	67,978	67,886	67,862	68,735	794,641
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)		61,944	61,991	61,938	63,235	64,394	69,310	71,301	68,067	67,978	67,886	67,862	68,735	794,641

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,232,602; Scholz $790,065; Smith $688,899; Daniel $586,912 Ending Balances: Crist, $2,232,602; Scholz $916,803; Smith $1,317,122; Daniel $581,275.
(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: 3.2%; Smith 2.5%; Scholz 4.2%; Daniel 3.1% 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 2008 - December 2008

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)	(179,302)	(181,138)	(182,974)	(184,811)	(186,647)	(188,483)	(190,320)	(192,156)	(193,992)	(195,829)	(197,665)	(199,501)	(201,338)	
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)	738,722	736,886	735,050	733,213	731,377	729,541	727,704	725,868	724,032	722,195	720,359	718,523	716,686	
6	Average Net Investment		737,805	735,969	734,132	732,296	730,460	728,623	726,787	724,951	723,114	721,278	719,442	717,605	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,420	5,407	5,393	5,380	5,367	5,354	5,340	5,327	5,313	5,300	5,285	5,272	64,158
	b Debt Component (Line 6 x Debt Component x 1/12)		1,539	1,536	1,532	1,529	1,524	1,521	1,517	1,513	1,509	1,506	1,502	1,497	18,225
8	Investment Expenses														
	a Depreciation (E)		1,836	1,836	1,837	1,836	1,836	1,837	1,836	1,836	1,837	1,836	1,836	1,837	22,036
	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)		8,795	8,779	8,762	8,745	8,727	8,712	8,693	8,676	8,659	8,642	8,623	8,606	104,419
	a Recoverable Costs Allocated to Energy		676	676	675	672	671	670	669	668	666	664	663	662	8,032
	b Recoverable Costs Allocated to Demand		8,119	8,103	8,087	8,073	8,056	8,042	8,024	8,008	7,993	7,978	7,960	7,944	96,387
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		652	653	653	651	651	649	649	648	646	643	641	639	7,775
13	Retail Demand-Related Recoverable Costs (I)		7,828	7,813	7,798	7,784	7,768	7,754	7,737	7,721	7,707	7,693	7,675	7,660	92,938
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,480	8,466	8,451	8,435	8,419	8,403	8,386	8,369	8,353	8,336	8,316	8,299	100,713

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 4% annually, PEs 3400 and 3412 depreciable at 2 4% 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 2008 - December 2008

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	28	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	28	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)	242,944	242,944	242,944	242,944	242,944	242,944	242,944	242,972	242,972	242,972	242,972	242,972	242,972	
3	Less: Accumulated Depreciation (C)	(56,572)	(57,166)	(57,760)	(58,354)	(58,948)	(59,541)	(60,135)	(60,729)	(61,323)	(61,916)	(62,510)	(63,104)	(63,696)	
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)	186,372	185,778	185,184	184,590	183,996	183,403	182,809	182,243	181,649	181,056	180,462	179,868	179,276	
6	Average Net Investment		186,075	185,481	184,887	184,293	183,700	183,106	182,526	181,946	181,353	180,759	180,165	179,573	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,367	1,362	1,359	1,354	1,350	1,346	1,341	1,337	1,332	1,328	1,323	1,319	16,118
	b Debt Component (Line 6 x Debt Component x 1/12)		388	387	386	385	384	382	381	379	378	378	376	375	4,579
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	593	594	594	594	593	594	594	592	7,124
	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)		2,349	2,343	2,339	2,333	2,327	2,322	2,316	2,310	2,303	2,300	2,293	2,286	27,821
	a Recoverable Costs Allocated to Energy		181	181	180	179	179	178	178	178	178	177	176	176	2,141
	b Recoverable Costs Allocated to Demand		2,168	2,162	2,159	2,154	2,148	2,144	2,138	2,132	2,125	2,123	2,117	2,110	25,680
10	Energy Jurisdictional Factor		0 9634865	0 9658052	0.9666186	0 9687846	0 9687876	0 9686688	0 9696144	0 9688390	0 9696486	0 9683344	0 9661598	0 9642849	
11	Demand Jurisdictional Factor		0.9642160	0 9642160	0.9642160	0 9642160	0 9642160	0.9642160	0.9642160	0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	
12	Retail Energy-Related Recoverable Costs (H)		175	175	174	174	174	173	173	173	173	172	170	170	2,076
13	Retail Demand-Related Recoverable Costs (I)		2,090	2,085	2,082	2,077	2,071	2,067	2,061	2,056	2,049	2,047	2,041	2,034	24,760
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,265	2,260	2,256	2,251	2,245	2,240	2,234	2,229	2,222	2,219	2,211	2,204	26,836

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning balances: Crist $149,921; Smith $93,023 Ending balances Crist $149,949: 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 2%; Smith 2.5% 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 2008 - December 2008

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		(5,004)	1,398	0	(251)	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)	512,169	507,003	508,239	508,077	507,664	507,502	507,340	507,178	507,016	506,854	506,692	506,530	506,368	
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)	512,169	507,003	508,239	508,077	507,664	507,502	507,340	507,178	507,016	506,854	506,692	506,530	506,368	
6	Average Net Investment		509,586	507,621	508,158	507,871	507,583	507,421	507,259	507,097	506,935	506,773	506,611	506,449	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,744	3,729	3,733	3,731	3,729	3,728	3,727	3,726	3,724	3,723	3,722	3,721	44,737
	b Debt Component (Line 6 x Debt Component x 1/12)		1,064	1,059	1,061	1,060	1,059	1,059	1,059	1,058	1,058	1,058	1,057	1,057	12,709
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		162	162	162	162	162	162	162	162	162	162	162	162	1,944
	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)		4,970	4,950	4,956	4,953	4,950	4,949	4,948	4,946	4,944	4,943	4,941	4,940	59,390
	a Recoverable Costs Allocated to Energy		382	381	381	381	381	381	381	380	380	380	380	380	4,568
	b Recoverable Costs Allocated to Demand		4,588	4,569	4,575	4,572	4,569	4,568	4,567	4,566	4,564	4,563	4,561	4,560	54,822
10	Energy Jurisdictional Factor		0 9634865	0 9658052	0.9666186	0 9687846	0 9687876	0.9686688	0.9696144	0.9688390	0 9696486	0 9683344	0 9661598	0 9642849	
11	Demand Jurisdictional Factor		0.9642160	0 9642160	0.9642160	0.9642160	0 9642160	0.9642160	0.9642160	0.9642160	0 9642160	0 9642160	0 9642160	0 9642160	
12	Retail Energy-Related Recoverable Costs (H)		368	368	369	369	369	369	370	368	369	368	367	367	4,421
13	Retail Demand-Related Recoverable Costs (I)		4,424	4,406	4,411	4,408	4,406	4,405	4,404	4,403	4,401	4,400	4,398	4,397	52,863
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,792	4,774	4,780	4,777	4,775	4,774	4,774	4,771	4,770	4,768	4,765	4,764	57,284

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 2% 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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(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)	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)	(136,087)	(136,901)	(137,715)	(138,530)	(139,344)	(140,158)	(140,973)	(141,787)	(142,601)	(143,416)	(144,230)	(145,044)	(145,859)	
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)	169,236	168,422	167,608	166,793	165,979	165,165	164,350	163,536	162,722	161,907	161,093	160,279	159,464	
6	Average Net Investment		168,829	168,015	167,201	166,386	165,572	164,758	163,943	163,129	162,315	161,500	160,686	159,872	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,240	1,234	1,228	1,222	1,216	1,210	1,204	1,199	1,193	1,187	1,181	1,175	14,489
	b Debt Component (Line 6 x Debt Component x 1/12)		352	351	349	347	346	344	342	340	339	337	335	334	4,116
8	Investment Expenses														
	a Depreciation (E)		814	814	815	814	814	815	814	814	815	814	814	815	9,772
	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)		2,406	2,399	2,392	2,383	2,376	2,369	2,360	2,353	2,347	2,338	2,330	2,324	28,377
	a Recoverable Costs Allocated to Energy		185	185	184	183	183	182	182	181	181	180	179	179	2,184
	b Recoverable Costs Allocated to Demand		2,221	2,214	2,208	2,200	2,193	2,187	2,178	2,172	2,166	2,158	2,151	2,145	26,193
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		178	179	178	177	177	176	177	175	176	174	173	173	2,113
13	Retail Demand-Related Recoverable Costs (I)		2,142	2,135	2,129	2,121	2,115	2,109	2,100	2,094	2,088	2,081	2,074	2,068	25,256
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,320	2,314	2,307	2,298	2,292	2,285	2,277	2,269	2,264	2,255	2,247	2,241	27,369

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) 3.2% 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 2008 - December 2008

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)	(24,418)	(24,602)	(24,786)	(24,970)	(25,154)	(25,338)	(25,522)	(25,706)	(25,890)	(26,074)	(26,257)	(26,441)	(26,624)	
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)	44,505	44,321	44,137	43,953	43,769	43,585	43,401	43,217	43,033	42,849	42,666	42,482	42,299	
6	Average Net Investment		44,413	44,229	44,045	43,861	43,677	43,493	43,309	43,125	42,941	42,758	42,574	42,391	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		326	325	324	322	321	320	318	317	315	314	313	311	3,826
	b Debt Component (Line 6 x Debt Component x 1/12)		93	92	92	92	91	91	90	90	90	89	89	88	1,087
8	Investment Expenses														
	a Depreciation (E)		184	184	184	184	184	184	184	184	184	183	184	183	2,206
	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)		603	601	600	598	596	595	592	591	589	586	586	582	7,119
	a Recoverable Costs Allocated to Energy		46	46	46	46	46	46	46	45	45	45	45	45	547
	b Recoverable Costs Allocated to Demand		557	555	554	552	550	549	546	546	544	541	541	537	6,572
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		44	44	44	45	45	45	45	44	44	44	44	43	531
13	Retail Demand-Related Recoverable Costs (I)		537	535	534	532	530	529	526	526	525	522	522	518	6,336
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		581	579	578	577	575	574	571	570	569	566	566	561	6,867

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) 3.2% 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 2008 - December 2008

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)	(45,171)	(45,442)	(45,713)	(45,983)	(46,254)	(46,525)	(46,795)	(47,066)	(47,337)	(47,607)	(47,878)	(48,149)	(48,419)	
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)	56,324	56,053	55,782	55,512	55,241	54,970	54,700	54,429	54,158	53,888	53,617	53,346	53,076	
6	Average Net Investment		56,189	55,918	55,647	55,377	55,106	54,835	54,565	54,294	54,023	53,753	53,482	53,211	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		413	411	409	407	405	403	401	399	397	395	393	391	4,824
	b Debt Component (Line 6 x Debt Component x 1/12)		117	117	116	116	115	114	114	113	113	112	112	111	1,370
8	Investment Expenses														
	a Depreciation (E)		271	271	270	271	271	270	271	271	270	271	271	270	3,248
	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)		801	799	795	794	791	787	786	783	780	778	776	772	9,442
	a Recoverable Costs Allocated to Energy		62	61	61	61	61	61	60	60	60	60	60	59	726
	b Recoverable Costs Allocated to Demand		739	738	734	733	730	726	726	723	720	718	716	713	8,716
10	Energy Jurisdictional Factor		0 9634865	0 9658052	0 9666186	0.9687846	0.9687876	0.9686688	0 9696144	0 9688390	0.9696486	0 9683344	0 9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0 9642160	0 9642160	0.9642160	0.9642160	0.9642160	0.9642160	0 9642160	0 9642160	0 9642160	0.9642160	0 9642160	
12	Retail Energy-Related Recoverable Costs (H)		60	59	59	59	59	59	58	58	58	58	58	57	702
13	Retail Demand-Related Recoverable Costs (I)		713	712	708	707	704	700	700	697	694	692	690	687	8,404
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		773	771	767	766	763	759	758	755	752	750	748	744	9,106

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) 3.2% 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 2008 - December 2008

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)	(26,818)	(26,977)	(27,136)	(27,295)	(27,454)	(27,613)	(27,772)	(27,931)	(28,090)	(28,249)	(28,407)	(28,566)	(28,724)	
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)	32,725	32,566	32,407	32,248	32,089	31,930	31,771	31,612	31,453	31,294	31,136	30,977	30,819	
6	Average Net Investment		32,646	32,487	32,328	32,169	32,010	31,851	31,692	31,533	31,374	31,215	31,057	30,898	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		240	239	238	236	235	234	233	232	231	229	228	227	2,802
	b Debt Component (Line 6 x Debt Component x 1/12)		68	68	67	67	67	66	66	66	65	65	65	64	794
8	Investment Expenses														
	a Depreciation (E)		159	159	159	159	159	159	159	159	159	158	159	158	1,906
	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)		467	466	464	462	461	459	458	457	455	452	452	449	5,502
	a Recoverable Costs Allocated to Energy		36	36	36	36	35	35	35	35	35	35	35	35	424
	b Recoverable Costs Allocated to Demand		431	430	428	426	426	424	423	422	420	417	417	414	5,078
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		35	35	35	35	34	34	34	34	34	34	34	34	412
13	Retail Demand-Related Recoverable Costs (I)		416	415	413	411	411	409	408	407	405	402	402	399	4,898
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		451	450	448	446	445	443	442	441	439	436	436	433	5,310

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) 3.2% 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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
PE 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)	(48,220)	(49,201)	(50,182)	(51,163)	(52,144)	(53,125)	(54,106)	(55,087)	(56,068)	(57,049)	(58,029)	(59,010)	(59,991)	
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)	342,899	341,918	340,937	339,956	338,975	337,994	337,013	336,032	335,051	334,070	333,090	332,109	331,128	
6	Average Net Investment		342,409	341,428	340,447	339,466	338,485	337,504	336,523	335,542	334,561	333,580	332,600	331,619	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,516	2,509	2,501	2,494	2,487	2,480	2,472	2,466	2,458	2,450	2,444	2,436	29,713
	b Debt Component (Line 6 x Debt Component x 1/12)		715	712	710	709	706	705	702	701	698	696	694	692	8,440
8	Investment Expenses														
	a Depreciation (E)		981	981	981	981	981	981	981	981	981	980	981	981	11,771
	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)		4,212	4,202	4,192	4,184	4,174	4,166	4,155	4,148	4,137	4,126	4,119	4,109	49,924
	a Recoverable Costs Allocated to Energy		4,212	4,202	4,192	4,184	4,174	4,166	4,155	4,148	4,137	4,126	4,119	4,109	49,924
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		4,061	4,061	4,055	4,056	4,047	4,038	4,032	4,022	4,014	3,998	3,982	3,965	48,331
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)		4,061	4,061	4,055	4,056	4,047	4,038	4,032	4,022	4,014	3,998	3,982	3,965	48,331

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 2% annually; Smith 2 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 2008 - December 2008

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)	(1,073,517)	(1,079,313)	(1,085,109)	(1,090,905)	(1,096,701)	(1,102,497)	(1,108,293)	(1,114,089)	(1,119,885)	(1,125,681)	(1,131,478)	(1,137,274)	(1,143,071)	
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)	1,709,083	1,703,287	1,697,491	1,691,695	1,685,899	1,680,103	1,674,307	1,668,511	1,662,715	1,656,919	1,651,122	1,645,326	1,639,529	
6	Average Net Investment		1,706,185	1,700,389	1,694,593	1,688,797	1,683,001	1,677,205	1,671,409	1,665,613	1,659,817	1,654,021	1,648,224	1,642,428	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		12,535	12,493	12,450	12,408	12,365	12,322	12,280	12,237	12,195	12,152	12,110	12,067	147,614
	b Debt Component (Line 6 x Debt Component x 1/12)		3,561	3,549	3,537	3,525	3,512	3,500	3,488	3,476	3,464	3,452	3,440	3,428	41,932
8	Investment Expenses														
	a Depreciation (E)		5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,797	5,796	5,797	69,554
	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)		21,892	21,838	21,783	21,729	21,673	21,618	21,564	21,509	21,455	21,401	21,346	21,292	259,100
	a Recoverable Costs Allocated to Energy		1,684	1,680	1,676	1,671	1,667	1,663	1,659	1,655	1,650	1,646	1,642	1,638	19,931
	b Recoverable Costs Allocated to Demand		20,208	20,158	20,107	20,058	20,006	19,955	19,905	19,854	19,805	19,755	19,704	19,654	239,169
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,624	1,624	1,621	1,620	1,616	1,612	1,610	1,605	1,601	1,595	1,588	1,581	19,297
13	Retail Demand-Related Recoverable Costs (I)		19,485	19,437	19,387	19,340	19,290	19,241	19,193	19,144	19,096	19,048	18,999	18,951	230,611
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		21,109	21,061	21,008	20,960	20,906	20,853	20,803	20,749	20,697	20,643	20,587	20,532	249,908

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) 2.5% 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 2008 - December 2008

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)	104,476	104,103	103,731	103,358	102,986	102,613	102,241	101,868	101,496	101,123	100,750	100,377	100,003	
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)	283,438	283,065	282,693	282,320	281,948	281,575	281,203	280,830	280,458	280,085	279,712	279,339	278,965	
6	Average Net Investment		283,252	282,879	282,507	282,134	281,762	281,389	281,017	280,644	280,272	279,899	279,526	279,153	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,081	2,079	2,075	2,073	2,070	2,067	2,065	2,062	2,059	2,057	2,054	2,051	24,793
	b Debt Component (Line 6 x Debt Component x 1/12)		591	591	589	588	588	587	586	586	585	584	584	582	7,041
8	Investment Expenses														
	a Depreciation (E)		373	372	373	372	373	372	373	372	373	373	373	374	4,473
	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)		3,045	3,042	3,037	3,033	3,031	3,026	3,024	3,020	3,017	3,014	3,011	3,007	36,307
	a Recoverable Costs Allocated to Energy		235	234	233	233	233	232	232	232	232	232	231	231	2,790
	b Recoverable Costs Allocated to Demand		2,810	2,808	2,804	2,800	2,798	2,794	2,792	2,788	2,785	2,782	2,780	2,776	33,517
10	Energy Jurisdictional Factor		0 9634865	0.9658052	0.9666186	0.9687846	0 9687876	0 9686688	0 9696144	0 9688390	0 9696486	0 9683344	0 9661598	0 9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0 9642160	0.9642160	0.9642160	0 9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		227	226	225	226	226	225	225	225	225	225	223	223	2,701
13	Retail Demand-Related Recoverable Costs (I)		2,709	2,708	2,704	2,700	2,698	2,694	2,692	2,688	2,685	2,682	2,681	2,677	32,318
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,936	2,934	2,929	2,926	2,924	2,919	2,917	2,913	2,910	2,907	2,904	2,900	35,019

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) Smith 2 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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 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		0	0	0	0	0	394	10,061	0	72	(58)	2	(13)	
	b Clearings to Plant		0	0	0	0	0	0	0	0	10,527	(58)	2	(13)	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		835	2,423	554	0	639	0	427	(261)	4,498	7,161	2,180	2,870	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,204,320	16,204,262	16,204,264	16,204,251	
3	Less: Accumulated Depreciation (C)	(5,896,039)	(5,947,345)	(5,997,062)	(6,048,648)	(6,100,790)	(6,152,291)	(6,204,431)	(6,256,145)	(6,308,547)	(6,356,203)	(6,401,210)	(6,451,197)	(6,500,495)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	394	10,455	10,455	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,297,754	10,246,448	10,196,731	10,145,145	10,093,003	10,041,502	9,989,756	9,948,103	9,895,701	9,848,117	9,803,052	9,753,067	9,703,756	
6	Average Net Investment		10,272,101	10,221,590	10,170,938	10,119,074	10,067,253	10,015,629	9,968,930	9,921,902	9,871,909	9,825,585	9,778,060	9,728,412	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		75,469	75,098	74,726	74,345	73,964	73,584	73,242	72,896	72,529	72,189	71,839	71,474	881,355
	b Debt Component (Line 6 x Debt Component x 1/12)		21,438	21,333	21,227	21,119	21,010	20,902	20,805	20,707	20,603	20,506	20,407	20,303	250,360
8	Investment Expenses														
	a Depreciation (E)		41,829	41,828	41,828	41,830	41,828	41,828	41,829	41,829	41,842	41,856	41,855	41,856	502,038
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	123,744
	d Property Taxes		29,699	29,699	29,699	29,699	29,699	29,699	29,699	29,699	29,699	29,699	29,699	29,699	356,388
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		178,747	178,270	177,792	177,305	176,813	176,325	175,887	175,443	174,985	174,562	174,112	173,644	2,113,885
	a Recoverable Costs Allocated to Energy		13,750	13,713	13,677	13,639	13,601	13,563	13,530	13,496	13,460	13,428	13,393	13,358	162,608
	b Recoverable Costs Allocated to Demand		164,997	164,557	164,115	163,666	163,212	162,762	162,357	161,947	161,525	161,134	160,719	160,286	1,951,277
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,257	13,253	13,230	13,223	13,186	13,147	13,128	13,085	13,061	13,012	12,949	12,890	157,421
13	Retail Demand-Related Recoverable Costs (I)		159,093	158,668	158,242	157,809	157,372	156,938	156,547	156,152	155,745	155,368	154,968	154,550	1,881,452
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		172,350	171,921	171,472	171,032	170,558	170,085	169,675	169,237	168,806	168,380	167,917	167,440	2,038,873

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) 3.1% 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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P E 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)	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	
3	Less: Accumulated Depreciation (C)	(15,214)	(15,494)	(15,773)	(16,053)	(16,332)	(16,612)	(16,891)	(17,171)	(17,450)	(17,730)	(18,008)	(18,288)	(18,567)	
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)	118,919	118,639	118,360	118,080	117,801	117,521	117,242	116,962	116,683	116,403	116,125	115,845	115,566	
6	Average Net Investment		118,779	118,500	118,220	117,941	117,661	117,382	117,102	116,823	116,543	116,265	115,985	115,706	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		872	870	869	867	864	863	861	858	856	855	852	850	10,337
	b Debt Component (Line 6 x Debt Component x 1/12)		248	248	246	246	246	245	245	243	243	243	242	242	2,937
8	Investment Expenses														
	a Depreciation (E)		280	279	280	279	280	279	280	279	280	278	280	279	3,353
	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)		1,400	1,397	1,395	1,392	1,390	1,387	1,386	1,380	1,379	1,376	1,374	1,371	16,627
	a Recoverable Costs Allocated to Energy		107	107	107	107	107	107	106	106	106	106	106	106	1,279
	b Recoverable Costs Allocated to Demand		1,293	1,290	1,288	1,285	1,283	1,280	1,279	1,274	1,273	1,270	1,268	1,265	15,348
10	Energy Jurisdictional Factor		0 9634865	0 9658052	0.9666186	0 9687846	0 9687876	0 9686688	0.9696144	0 9688390	0 9696486	0 9683344	0 9661598	0 9642849	
11	Demand Jurisdictional Factor		0 9642160	0.9642160	0 9642160	0 9642160	0.9642160	0.9642160	0 9642160	0 9642160	0.9642160	0 9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		103	103	104	104	104	104	104	103	103	103	102	102	1,239
13	Retail Demand-Related Recoverable Costs (I)		1,247	1,244	1,242	1,239	1,237	1,234	1,233	1,228	1,227	1,225	1,223	1,220	14,799
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,350	1,347	1,346	1,343	1,341	1,338	1,337	1,331	1,330	1,328	1,325	1,322	16,038

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) 2.5% 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 2008 - December 2008

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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 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		15,772	686,332	2,518	(426)	581	4,004	(1,686)	575	2,636	(2,440)	(44,622)	304,513	
	b Clearings to Plant		15,772	1,150	61	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)	134,427,864	134,443,636	134,444,786	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	
3	Less: Accumulated Depreciation (C)	(12,843,244)	(13,232,242)	(13,621,263)	(14,010,286)	(14,399,308)	(14,788,331)	(15,177,354)	(15,566,377)	(15,955,399)	(16,344,422)	(16,733,445)	(17,122,468)	(17,511,490)	
4	CWIP - Non Interest Bearing	0	0	685,182	687,639	687,213	687,794	691,798	690,112	690,687	693,323	690,883	646,261	950,774	
5	Net Investment (Lines 2 + 3 + 4)	121,584,620	121,211,394	121,508,705	121,122,200	120,732,752	120,344,310	119,959,291	119,568,582	119,180,135	118,793,748	118,402,285	117,968,640	117,884,131	
6	Average Net Investment		121,398,007	121,360,050	121,315,453	120,927,476	120,538,531	120,151,801	119,763,937	119,374,359	118,986,942	118,598,017	118,185,463	117,926,386	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		891,912	891,632	891,306	888,454	885,595	882,755	879,906	877,044	874,197	871,340	868,308	866,405	10,568,854
	b Debt Component (Line 6 x Debt Component x 1/12)		253,358	253,279	253,185	252,376	251,564	250,756	249,948	249,134	248,326	247,514	246,653	246,112	3,002,205
8	Investment Expenses														
	a Depreciation (E)		358,026	358,049	358,051	358,051	358,051	358,051	358,051	358,051	358,051	358,051	358,051	358,051	4,296,585
	b Amortization (F)		2,292	2,292	2,292	2,291	2,292	2,292	2,292	2,291	2,292	2,292	2,292	2,291	27,501
	c Dismantlement		28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	344,160
	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)		1,534,268	1,533,932	1,533,514	1,529,852	1,526,182	1,522,534	1,518,877	1,515,200	1,511,546	1,507,877	1,503,984	1,501,539	18,239,305
	a Recoverable Costs Allocated to Energy		1,534,268	1,533,932	1,533,514	1,529,852	1,526,182	1,522,534	1,518,877	1,515,200	1,511,546	1,507,877	1,503,984	1,501,539	18,239,305
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,479,281	1,482,517	1,483,361	1,483,135	1,479,581	1,475,864	1,473,756	1,469,012	1,466,694	1,461,151	1,454,106	1,448,925	17,657,383
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)		1,479,281	1,482,517	1,483,361	1,483,135	1,479,581	1,475,864	1,473,756	1,469,012	1,466,694	1,461,151	1,454,106	1,448,925	17,657,383

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) Crist: 3 2% annually
(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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Stormwater Collection System
P E 1272
(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)	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	
3	Less: Accumulated Depreciation (C)	(30,629)	(33,082)	(35,535)	(37,988)	(40,442)	(42,895)	(45,348)	(47,801)	(50,255)	(52,708)	(55,161)	(57,615)	(60,068)	
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)	889,207	886,754	884,301	881,848	879,394	876,941	874,488	872,035	869,581	867,128	864,675	862,221	859,768	
6	Average Net Investment		887,981	885,528	883,075	880,621	878,168	875,715	873,262	870,808	868,355	865,902	863,448	860,995	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,524	6,506	6,488	6,470	6,452	6,434	6,416	6,398	6,380	6,362	6,344	6,326	77,100
	b Debt Component (Line 6 x Debt Component x 1/12)		1,853	1,848	1,843	1,838	1,833	1,828	1,822	1,817	1,812	1,807	1,802	1,797	21,900
8	Investment Expenses														
	a Depreciation (E)		2,453	2,453	2,453	2,454	2,453	2,453	2,453	2,454	2,453	2,453	2,454	2,453	29,439
	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)		10,830	10,807	10,784	10,762	10,738	10,715	10,691	10,669	10,645	10,622	10,600	10,576	128,439
	a Recoverable Costs Allocated to Energy		833	831	830	828	826	824	822	821	819	817	815	814	9,880
	b Recoverable Costs Allocated to Demand		9,997	9,976	9,954	9,934	9,912	9,891	9,869	9,848	9,826	9,805	9,785	9,762	118,559
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		803	803	803	803	801	799	798	796	795	792	788	785	9,566
13	Retail Demand-Related Recoverable Costs (I)		9,639	9,619	9,598	9,579	9,557	9,537	9,516	9,496	9,474	9,454	9,435	9,413	114,317
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,442	10,422	10,401	10,382	10,358	10,336	10,314	10,292	10,269	10,246	10,223	10,198	123,883

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 2% 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 2008 - December 2008

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	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)	(7,895)	(8,063)	(8,231)	(8,398)	(8,566)	(8,734)	(8,901)	(9,069)	(9,237)	(9,404)	(9,572)	(9,740)	(9,907)	
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)	54,975	54,807	54,639	54,472	54,304	54,136	53,969	53,801	53,633	53,466	53,298	53,130	52,963	
6	Average Net Investment		54,891	54,723	54,556	54,388	54,220	54,053	53,885	53,717	53,550	53,382	53,214	53,047	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		403	402	401	400	398	397	396	395	393	392	391	390	4,758
	b Debt Component (Line 6 x Debt Component x 1/12)		115	114	114	114	113	113	112	112	112	111	111	111	1,352
8	Investment Expenses														
	a Depreciation (E)		168	168	167	168	168	167	168	168	167	168	168	167	2,012
	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)		686	684	682	682	679	677	676	675	672	671	670	668	8,122
	a Recoverable Costs Allocated to Energy		686	684	682	682	679	677	676	675	672	671	670	668	8,122
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0 9634865	0 9658052	0.9666186	0 9687846	0 9687876	0 9686688	0 9696144	0.9688390	0 9696486	0 9683344	0 9661598	0 9642849	
11	Demand Jurisdictional Factor		0 9642160	0 9642160	0.9642160	0.9642160	0 9642160	0.9642160	0.9642160	0.9642160	0 9642160	0.9642160	0 9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		661	661	660	661	658	656	656	654	652	650	648	645	7,862
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)		661	661	660	661	658	656	656	654	652	650	648	645	7,862

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) 3 2% 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 2008 - December 2008

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		2,535,141	2,977,155	2,109,373	1,109,428	336,771	63,963	47,649	50,433	59,512	(29,396)	8,342	(2,908)	
	b Clearings to Plant		18,648	(11,425)	12,355,971	1,109,428	336,771	63,963	47,649	50,433	59,512	(29,396)	8,342	(2,908)	
	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)	15,832,690	15,851,338	15,839,913	28,195,884	29,305,312	29,642,083	29,706,046	29,753,695	29,804,128	29,863,640	29,834,244	29,842,586	29,839,678	
3	Less: Accumulated Depreciation (C)	(701,457)	(734,635)	(767,826)	(817,473)	(885,079)	(954,611)	(1,024,678)	(1,094,893)	(1,165,242)	(1,235,737)	(1,306,272)	(1,376,778)	(1,447,293)	
4	CWIP - Non Interest Bearing	4,741,525	7,258,018	10,246,598	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	19,872,758	22,374,721	25,318,685	27,378,411	28,420,233	28,687,472	28,681,368	28,658,802	28,638,886	28,627,903	28,527,972	28,465,808	28,392,385	
6	Average Net Investment		21,123,740	23,846,703	26,348,548	27,899,322	28,553,853	28,684,420	28,670,085	28,648,844	28,633,395	28,577,938	28,496,890	28,429,097	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		155,196	175,202	193,583	204,976	209,787	210,744	210,639	210,484	210,369	209,962	209,367	208,868	2,409,177
	b Debt Component (Line 6 x Debt Component x 1/12)		44,086	49,768	54,990	58,227	59,592	59,865	59,835	59,789	59,758	59,642	59,472	59,332	684,356
8	Investment Expenses														
	a Depreciation (E)		33,178	33,191	49,647	67,606	69,532	70,067	70,215	70,349	70,495	70,535	70,506	70,515	745,836
	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)		232,460	258,161	298,220	330,809	338,911	340,676	340,689	340,622	340,622	340,139	339,345	338,715	3,839,369
	a Recoverable Costs Allocated to Energy		232,460	258,161	298,220	330,809	338,911	340,676	340,689	340,622	340,622	340,139	339,345	338,715	3,839,369
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		224,129	249,508	288,467	320,707	328,563	330,233	330,568	330,239	330,515	329,599	328,091	326,846	3,717,465
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)		224,129	249,508	288,467	320,707	328,563	330,233	330,568	330,239	330,515	329,599	328,091	326,846	3,717,465

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Smith $15,715,200; Scholz $117,490 Ending Balances: Crist, $13,997,697; Smith $15,715,200; 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 3.2%; Smith 2.5%; Scholz 4.2% 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 2008 - December 2008

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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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 3.2% annually; Scholz 4.2% 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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E.'s 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		0	0	0	0	0	0	0	0	0	0	0	73,956	
	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)	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	
3	Less: Accumulated Depreciation (C)	(3,148)	(3,398)	(3,648)	(3,898)	(4,148)	(4,398)	(4,648)	(4,898)	(5,148)	(5,398)	(5,648)	(5,898)	(6,148)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	73,956	
5	Net Investment (Lines 2 + 3 + 4)	90,587	90,337	90,087	89,837	89,587	89,337	89,087	88,837	88,587	88,337	88,087	87,837	161,543	
6	Average Net Investment		90,462	90,212	89,962	89,712	89,462	89,212	88,962	88,712	88,462	88,212	87,962	124,690	
7	Return on Average Net Investment														
	a Equity Compoonent (Line 6 x Equity Component x 1/12) (D)		665	663	661	659	657	655	654	652	650	648	646	916	8,126
	b Debt Component (Line 6 x Debt Component x 1/12)		189	188	188	187	187	186	186	185	185	184	184	260	2,309
8	Investment Expenses														
	a Depreciation (E)		250	250	250	250	250	250	250	250	250	250	250	250	3,000
	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)		1,104	1,101	1,099	1,096	1,094	1,091	1,090	1,087	1,085	1,082	1,080	1,426	13,435
	a Recoverable Costs Allocated to Energy		85	85	85	84	84	84	84	84	83	83	83	110	1,034
	b Recoverable Costs Allocated to Demand		1,019	1,016	1,014	1,012	1,010	1,007	1,006	1,003	1,002	999	997	1,316	12,401
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		82	82	82	81	81	81	82	81	81	80	80	106	999
13	Retail Demand-Related Recoverable Costs (I)		983	980	978	976	974	971	970	967	966	963	961	1,269	11,958
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,065	1,062	1,060	1,057	1,055	1,052	1,052	1,048	1,047	1,043	1,041	1,375	12,957

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) 3.2% 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 2008 - December 2008

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		0	0	0	0	0	14,165	429,961	(332,359)	10,372	8,916	997	9,263	
	b Clearings to Plant		0	0	0	0	0	0	357,658	(357,658)	0	0	132,052	9,263	
	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)	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	6,185,365	5,827,707	5,827,707	5,827,707	5,959,759	5,969,022	
3	Less: Accumulated Depreciation (C)	(310,347)	(325,890)	(341,432)	(356,975)	(372,517)	(388,060)	(403,602)	(419,622)	(435,641)	(451,184)	(466,726)	(482,445)	(498,352)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	14,165	86,468	111,767	122,139	131,055	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,517,360	5,501,817	5,486,275	5,470,732	5,455,190	5,439,647	5,438,270	5,852,211	5,503,833	5,498,662	5,492,036	5,477,314	5,470,670	
6	Average Net Investment		5,509,589	5,494,046	5,478,504	5,462,961	5,447,419	5,438,959	5,645,241	5,678,022	5,501,248	5,495,349	5,484,675	5,473,992	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,479	40,365	40,251	40,136	40,022	39,960	41,476	41,716	40,417	40,374	40,296	40,218	485,710
	b Debt Component (Line 6 x Debt Component x 1/12)		11,499	11,466	11,434	11,401	11,369	11,351	11,782	11,850	11,481	11,469	11,446	11,425	137,973
8	Investment Expenses														
	a Depreciation (E)		15,543	15,542	15,543	15,542	15,543	15,542	16,020	16,019	15,543	15,542	15,719	15,907	188,005
	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)		67,521	67,373	67,228	67,079	66,934	66,853	69,278	69,585	67,441	67,385	67,461	67,550	811,688
	a Recoverable Costs Allocated to Energy		5,194	5,183	5,171	5,160	5,149	5,142	5,330	5,353	5,188	5,184	5,189	5,196	62,439
	b Recoverable Costs Allocated to Demand		62,327	62,190	62,057	61,919	61,785	61,711	63,948	64,232	62,253	62,201	62,272	62,354	749,249
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		5,008	5,009	5,002	5,002	4,992	4,984	5,172	5,190	5,034	5,023	5,017	5,014	60,447
13	Retail Demand-Related Recoverable Costs (I)		60,097	59,965	59,836	59,703	59,574	59,503	61,660	61,934	60,025	59,975	60,044	60,123	722,439
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		65,105	64,974	64,838	64,705	64,566	64,487	66,832	67,124	65,059	64,998	65,061	65,137	782,886

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) 3.2% 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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1222, 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		830,025	331,656	719,566	16,357,754	3,012,664	3,258,228	911,121	1,643,992	2,038,220	97,002	2,273,958	3,217,262	
	b Clearings to Plant		40,901	285,642	86,162	15,188,343	2,209,064	612,699	9,917	538,595	43,048	(8,471)	1,019,078	10,825,472	
	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)	29,838,820	29,879,721	30,165,363	30,251,525	45,439,868	47,648,932	48,261,631	48,271,548	48,810,143	48,853,191	48,844,720	49,863,798	60,689,270	
3	Less: Accumulated Depreciation (C)	(487,156)	(566,022)	(645,303)	(725,183)	(825,566)	(949,149)	(1,076,496)	(1,204,675)	(1,333,799)	(1,463,912)	(1,594,074)	(1,725,427)	(1,870,105)	
4	CWIP - Non Interest Bearing	688,520	1,477,644	1,523,658	2,157,062	3,326,473	4,130,073	6,775,602	7,676,806	8,782,203	10,777,375	10,882,848	12,137,728	4,529,518	
5	Net Investment (Lines 2 + 3 + 4)	30,040,184	30,791,343	31,043,718	31,683,404	47,940,775	50,829,856	53,960,737	54,743,679	56,258,547	58,166,654	58,133,494	60,276,099	63,348,683	
6	Average Net Investment		30,415,764	30,917,531	31,363,561	39,812,090	49,385,316	52,395,297	54,352,208	55,501,113	57,212,601	58,150,074	59,204,797	61,812,391	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		223,464	227,152	230,425	292,498	362,834	384,948	399,324	407,768	420,342	427,228	434,975	454,135	4,265,093
	b Debt Component (Line 6 x Debt Component x 1/12)		63,478	64,525	65,456	83,088	103,066	109,348	113,431	115,831	119,401	121,360	123,561	129,003	1,211,548
8	Investment Expenses														
	a Depreciation (E)		78,408	78,823	79,422	99,925	123,125	126,889	127,721	128,666	129,655	129,704	130,895	144,220	1,377,453
	b Amortization (F)		458	458	458	458	458	458	458	458	458	458	458	458	5,496
	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)		365,808	370,958	375,761	475,969	589,483	621,643	640,934	652,723	669,856	678,750	689,889	727,816	6,859,590
	a Recoverable Costs Allocated to Energy		365,808	370,958	375,761	475,969	589,483	621,643	640,934	652,723	669,856	678,750	689,889	727,816	6,859,590
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		352,698	358,524	363,472	461,434	571,484	602,588	621,894	632,826	649,980	657,717	667,010	702,313	6,641,940
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)		352,698	358,524	363,472	461,434	571,484	602,588	621,894	632,826	649,980	657,717	667,010	702,313	6,641,940

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $29,626,570; Smith $212,250; Daniel $0, Scholz $0 Ending Balances: Crist $49,169,695; Smith $7,698,377, Daniel $3,264,866, Scholz $556,331
(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: 3.2%, Plant Smith Steam 2.5%, Smith CT 0.4%, Daniel 3.1%, Scholz 4.2%. Portion of PE 1222 is transmission 0.1833%, 0.1917%, 0.3417%, 0.2167%
(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 2008 - December 2008

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)	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	
3	Less: Accumulated Depreciation (C)	0	(394)	(788)	(1,182)	(1,577)	(1,971)	(2,365)	(2,759)	(3,154)	(3,548)	(3,942)	(4,336)	(4,731)	
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)	23,654	23,260	22,866	22,472	22,077	21,683	21,289	20,895	20,500	20,106	19,712	19,318	18,923	
6	Average Net Investment		23,457	23,063	22,669	22,275	21,880	21,486	21,092	20,698	20,303	19,909	19,515	19,121	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		172	169	167	164	161	158	155	152	149	146	143	140	1,876
	b Debt Component (Line 6 x Debt Component x 1/12)		49	48	47	46	46	45	44	43	42	42	41	40	533
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		394	394	394	395	394	394	394	395	394	394	394	395	4,731
	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)		615	611	608	605	601	597	593	590	585	582	578	575	7,140
	a Recoverable Costs Allocated to Energy		47	47	47	47	46	46	46	45	45	45	44	44	549
	b Recoverable Costs Allocated to Demand		568	564	561	558	555	551	547	545	540	537	534	531	6,591
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		45	45	45	46	45	45	45	44	44	44	43	42	533
13	Retail Demand-Related Recoverable Costs (I)		548	544	541	538	535	531	527	525	521	518	515	512	6,355
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		593	589	586	584	580	576	572	569	565	562	558	554	6,888

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 2008 - December 2008

Return on Working Capital, Mercury 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 SO2 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 9634865	0.9658052	0.9666186	0.9687846	0 9687876	0 9686688	0 9696144	0.9688390	0 9696486	0 9683344	0 9661598	0 9642849	
11	Demand Jurisdictional Factor		0 9642160	0.9642160	0 9642160	0.9642160	0 9642160	0 9642160	0 9642160	0 9642160	0.9642160	0 9642160	0.9642160	0 9642160	
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 Based on ROE of 12% and weighted income tax rate of 38.575%
(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 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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	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 SO2 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 9634865	0 9658052	0 9666186	0.9687846	0 9687876	0 9686688	0.9696144	0 9688390	0 9696486	0 9683344	0 9661598	0.9642849	
11	Demand Jurisdictional Factor		0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	0 9642160	0.9642160	
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 Based on ROE of 12% and weighted income tax rate of 38 575%
(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 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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	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 SO2 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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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 Based on ROE of 12% and weighted income tax rate of 38 5759%
(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 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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	0	0	427,351	(38,638)	40,559	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	14,376,402	13,804,389	13,285,714	12,778,314	12,260,506	11,763,103	11,130,296	10,412,487	9,738,797	9,143,964	8,733,817	8,324,799	7,911,392	
	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	(1,042,409)	(1,034,188)	(1,025,967)	(1,017,746)	(1,009,525)	(1,389,039)	(1,308,084)	(1,299,566)	(1,250,489)	(1,201,412)	(1,152,335)	(1,103,258)	(1,054,181)	
3	Total Working Capital Balance	13,333,993	12,770,201	12,259,747	11,760,568	11,250,981	10,374,064	9,822,212	9,112,921	8,488,308	7,942,552	7,581,482	7,221,541	6,857,211	
4	Average Net Working Capital Balance		13,052,097	12,514,974	12,010,157	11,505,774	10,812,522	10,098,138	9,467,566	8,800,614	8,215,430	7,762,017	7,401,511	7,039,376	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		95,894	91,948	88,239	84,533	79,440	74,191	69,558	64,658	60,359	57,028	54,379	51,718	871,945
	b Debt Component (Line 4 x Debt Component x 1/12)		27,240	26,119	25,065	24,013	22,566	21,075	19,759	18,367	17,146	16,199	15,447	14,691	247,687
6	Total Return Component (D)		123,134	118,067	113,304	108,546	102,006	95,266	89,317	83,025	77,505	73,227	69,826	66,409	1,119,632
7	Expenses														
	a Gains		(8,221)	(8,221)	(8,221)	(8,221)	(47,837)	(42,317)	(49,077)	(49,077)	(49,077)	(49,077)	(49,077)	(49,077)	(417,500)
	b Losses		0	0	0	0	0	0	0	0	0	0	0		0
	c SO2 Allowance Expense		572,013	518,675	507,400	517,808	497,403	632,807	717,809	673,690	594,833	410,147	409,018	413,407	6,465,010
8	Net Expenses (E)		563,792	510,454	499,179	509,587	449,566	590,490	668,732	624,613	545,756	361,070	359,941	364,330	6,047,510
9	Total System Recoverable Expenses (Lines 6 + 8)		686,926	628,521	612,483	618,133	551,572	685,756	758,049	707,638	623,261	434,297	429,767	430,739	7,167,142
	a Recoverable Costs Allocated to Energy		686,926	628,521	612,483	618,133	551,572	685,756	758,049	707,638	623,261	434,297	429,767	430,739	7,167,142
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9614865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		662,307	607,454	592,452	599,257	534,730	664,735	735,530	686,067	604,767	420,839	415,514	415,646	6,939,298
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)		662,307	607,454	592,452	599,257	534,730	664,735	735,530	686,067	604,767	420,839	415,514	415,646	6,939,298

Notes:
(A) Equity Component has been grossed up for taxes Based on ROE of 12% and weighted income tax rate of 38 5759%
(B) Line 9a x Line 10 x 1.0007 line loss multipher
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

Schedule 1E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

Line		Period Amount ($)
1	Over/(Under) Recovery for the current period (Schedule 2E, Line 5)	380,995
2	Interest Provision (Schedule 2E, Line 6)	24,132
3	Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2010 - December 2010 (Lines 1 + 2)	405,127

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 33
COMPANY Gulf Power Company (Direct)
WITNESS R. W. Dodd (RWD-2)
DATE 11/02/09

Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	6,067,061	5,402,835	5,434,031	5,599,141	6,665,802	8,490,566	8,338,461	8,318,469	7,134,880	6,129,612	5,412,518	6,256,549	79,249,926
2	True-Up Provision (Order No. PSC-08-0775-FOF-EI)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,653)	(1,339,820)
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	5,955,410	5,291,184	5,322,379	5,487,490	6,554,150	8,378,914	8,226,809	8,206,817	7,023,228	6,017,960	5,300,866	6,144,896	77,910,106
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	349,748	1,311,706	1,180,305	1,459,214	2,241,236	2,503,337	3,744,465	4,093,259	4,384,950	3,504,031	3,587,058	4,576,384	32,935,693
	b Capital Investment Projects (Schedule 7E, Line 9)	3,261,259	3,288,480	3,353,293	3,421,103	3,457,904	3,535,159	3,597,454	3,571,015	3,536,508	3,501,391	3,474,184	6,595,668	44,593,418
	c **Total Jurisdictional ECRC Costs**	3,611,007	4,600,186	4,533,598	4,880,317	5,699,140	6,038,496	7,341,919	7,664,274	7,921,458	7,005,422	7,061,242	11,172,052	77,529,111
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	2,344,403	690,998	788,781	607,173	855,010	2,340,418	884,890	542,543	(898,230)	(987,462)	(1,760,376)	(5,027,156)	380,995
6	Interest Provision (Schedule 3E, Line 10)	703	1,862	2,034	1,808	1,580	1,930	2,583	2,825	2,806	2,565	2,197	1,239	24,132
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2008	(1,428,879)	1,027,879	1,832,390	2,734,857	3,455,489	4,423,731	6,877,731	7,876,856	8,533,876	7,750,104	6,876,859	5,230,332	(1,428,879)
	b Final True-Up from January 2007 - December 2007 (Order No. PSC-08-0775-FOF-EI)	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471
8	True-Up Collected/(Refunded) (see Line 2)	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,653	1,339,820
9	Adjustments													
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	2,498,350	3,302,861	4,205,328	4,925,960	5,894,202	8,348,202	9,347,327	10,004,347	9,220,575	8,347,330	6,700,803	1,786,539	1,786,539

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	41,592	2,498,350	3,302,861	4,205,328	4,925,960	5,894,202	8,348,202	9,347,327	10,004,347	9,220,575	8,347,330	6,700,803	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	2,497,647	3,300,999	4,203,294	4,924,152	5,892,622	8,346,272	9,344,744	10,001,522	9,217,769	8,344,765	6,698,606	1,785,300	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	2,539,239	5,799,348	7,506,154	9,129,479	10,818,582	14,240,474	17,692,946	19,348,849	19,222,116	17,565,340	15,045,936	8,486,103	
4	Average True-Up Amount (Line 3 x 1/2)	1,269,619	2,899,674	3,753,077	4,564,740	5,409,291	7,120,237	8,846,473	9,674,424	9,611,058	8,782,670	7,522,968	4,243,051	
5	Interest Rate (First Day of Reporting Business Month)	0.005400	0.007900	0.007500	0.005500	0.004000	0.003000	0.003500	0.003500	0.003500	0.003500	0.003500	0.003500	
6	Interest Rate (First Day of Subsequent Business Month)	0.007900	0.007500	0.005500	0.004000	0.003000	0.003500	0.003500	0.003500	0.003500	0.003500	0.003500	0.003500	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.013300	0.015400	0.013000	0.009500	0.007000	0.006500	0.007000	0.007000	0.007000	0.007000	0.007000	0.007000	
8	Average Interest Rate (Line 7 x 1/2)	0.006650	0.007700	0.006500	0.004750	0.003500	0.003250	0.003500	0.003500	0.003500	0.003500	0.003500	0.003500	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.000554	0.000642	0.000542	0.000396	0.000292	0.000271	0.000292	0.000292	0.000292	0.000292	0.000292	0.000292	
10	Interest Provision for the Month (Line 4 x Line 9)	703	1,862	2,034	1,808	1,580	1,930	2,583	2,825	2,806	2,565	2,197	1,239	24,132

Schedule 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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	896,914	964,374	(67,460)	(7.0) %
.3	Title V	117,587	129,352	(11,765)	(9.1) %
.4	Asbestos Fees	3,404	2,500	904	36.2 %
.5	Emission Monitoring	609,314	656,209	(46,895)	(7.1) %
.6	General Water Quality	585,921	556,074	29,847	5.4 %
.7	Groundwater Contamination Investigation	1,548,387	1,631,176	(82,789)	(5.1) %
.8	State NPDES Administration	46,062	42,000	4,062	9.7 %
.9	Lead and Copper Rule	15,989	20,400	(4,411)	(21.6) %
.10	Env Auditing/Assessment	12,226	7,300	4,926	67.5 %
.11	General Solid & Hazardous Waste	481,274	417,471	63,803	15.3 %
.12	Above Ground Storage Tanks	56,237	90,100	(33,863)	(37.6) %
.13	Low Nox	0	0	0	0.0 %
.14	Ash Pond Diversion Curtains	1,003,700	800,000	203,700	25.5 %
.15	Mercury Emissions	0	0	0	0.0 %
.16	Sodium Injection	175,841	313,000	(137,159)	(43.8) %
.17	Gulf Coast Ozone Study	0	0	0	0.0 %
.18	SPCC Substation Project	(27,395)	0	(27,395)	0.0 %
.19	FDEP NOX Reduction Agreement	2,442,072	4,168,665	(1,726,593)	(41.4) %
.20	CAIR/CAMR/CAVR Compliance Program	2,738,176	5,972,528	(3,234,352)	(54.2) %
.21	Mercury Allowances	0	0	0	0.0 %
.22	Annual NOx Allowances	16,976,956	18,635,785	(1,658,829)	(8.9) %
.23	Seasonal NOx Allowances	964,576	2,154,990	(1,190,414)	(55.2) %
.24	SO2 Allowances	5,420,531	5,912,773	(492,242)	(8.3) %
2	Total O & M Activities	34,067,772	42,474,697	(8,406,925)	(19.8) %
3	Recoverable Costs Allocated to Energy	31,345,667	39,707,676	(8,362,009)	(21.1) %
4	Recoverable Costs Allocated to Demand	2,722,105	2,767,020	(44,915)	(1.6) %

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-08-0775-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 2009 - December 2009

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	-	772,540	-	-	-	-	-	-	-	-	124,374	-	896,914	0	896,914
	.3 Title V	8,338	6,559	7,489	10,925	6,205	10,154	17,944	9,190	9,620	9,696	10,885	10,582	117,587	0	117,587
	.4 Asbestos Fees	1,500	-	904	-	-	-	-	-	-	-	-	1,000	3,404	3,404	0
	.5 Emission Monitoring	37,623	44,799	46,766	19,604	72,503	45,319	56,078	57,740	55,535	57,447	52,097	63,803	609,314	0	609,314
	.6 General Water Quality	13,930	18,674	25,203	16,026	12,442	70,228	60,743	70,345	90,695	102,745	68,345	36,545	585,921	585,921	0
	.7 Groundwater Contamination Investigation	59,115	83,125	91,563	43,612	66,587	380,863	94,957	78,733	413,633	78,733	78,733	78,733	1,548,387	1,548,387	0
	.8 State NPDES Administration	-	4,062	-	-	-	-	-	-	-	-	7,500	34,500	46,062	46,062	0
	.9 Lead and Copper Rule	-	36	-	-	3,953	-	-	4,000	-	4,000	-	4,000	15,989	15,989	0
	.10 Env Auditing/Assessment	3	31	6,955	-	4,647	2,401	(3,111)	-	650	-	-	650	12,226	12,226	0
	.11 General Solid & Hazardous Waste	40,996	26,760	53,760	93,690	734	58,426	40,896	32,013	34,744	32,745	32,746	33,764	481,274	481,274	0
	.12 Above Ground Storage Tanks	780	2,236	1,540	4,328	1,528	(1,035)	3,000	1,500	30,860	2,500	7,500	1,500	56,237	56,237	0
	.13 Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	170,200	318,000	159,000	356,500	-	1,003,700	0	1,003,700
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	18,564	9,147	10,987	9,787	17,543	8,563	20,000	12,750	21,500	13,000	20,500	13,500	175,841	0	175,841
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	(27,395)	-	-	-	-	-	-	-	-	-	-	-	(27,395)	(27,395)	0
	.19 FDEP NOX Reduction Agreement	(9,942)	178,291	226,174	67,132	149,524	100,177	186,657	197,884	200,759	669,633	269,191	206,592	2,442,072	0	2,442,072
	.20 CAIR/CAMR/CAVR Compliance Program	33,823	108,098	10,403	25,120	98,959	128,283	164,001	162,593	162,656	164,156	222,656	1,457,428	2,738,176	0	2,738,176
	.21 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.22 Annual NOx Allowances	-	-	574,101	1,035,552	1,370,250	1,335,942	2,167,270	2,367,617	2,192,942	1,868,272	1,963,205	2,101,806	16,976,956	0	16,976,956
	.23 Seasonal NOx Allowances	-	-	-	-	182,048	161,239	212,318	212,318	196,654	-	-	-	964,576	0	964,576
	.24 SO2 Allowances	185,350	105,270	165,326	180,777	326,980	284,560	846,383	853,399	804,290	465,051	504,768	698,377	5,420,531	0	5,420,531
2	Total of O & M Activities	362,685	1,359,628	1,221,171	1,506,553	2,313,902	2,585,120	3,867,136	4,230,282	4,532,538	3,626,978	3,719,000	4,742,780	34,067,772	2,722,105	31,345,667
3	Recoverable Costs Allocated to Energy	273,756	1,224,704	1,041,246	1,348,897	2,224,011	2,074,237	3,670,651	4,043,691	3,961,956	3,406,255	3,524,176	4,552,088	31,345,667		
4	Recoverable Costs Allocated to Demand	88,929	134,924	179,925	157,656	89,891	510,883	196,485	186,591	570,582	220,723	194,824	190,692	2,722,105		
5	Retail Energy Jurisdictional Factor	0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (A)	264,001	1,181,610	1,006,818	1,307,200	2,154,562	2,010,735	3,555,011	3,913,345	3,834,786	3,291,206	3,399,206	4,392,516	30,310,996		
8	Jurisdictional Demand Recoverable Costs (B)	85,747	130,096	173,487	152,014	86,674	492,602	189,454	179,914	550,164	212,825	187,852	183,868	2,624,697		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	349,748	1,311,706	1,180,305	1,459,214	2,241,236	2,503,337	3,744,465	4,093,259	4,384,950	3,504,031	3,587,058	4,576,384	32,935,693		

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 2009 - December 2009

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	42,783	42,783	0	0.0	%
.2	Crist 5, 6 & 7 Precipitator Projects	1,875,933	1,946,449	(70,516)	(3.6)	%
.3	Crist 7 Flue Gas Conditioning	168,416	168,416	0	0.0	%
.4	Low NOx Burners, Crist 6 & 7	2,019,321	2,019,321	0	0.0	%
.5	CEMS - Plants Crist, Scholz, Smith, & Daniel	924,002	873,071	50,931	5.8	%
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	101,917	101,919	(2)	(0.0)	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	27,019	27,017	2	0.0	%
.8	Crist Cooling Tower Cell	59,161	59,161	0	0.0	%
.9	Crist 1-5 Dechlorination	27,271	27,271	0	0.0	%
.10	Crist Diesel Fuel Oil Remediation	6,872	6,872	0	0.0	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	9,076	9,076	0	0.0	%
.12	Crist IWW Sampling System	5,289	5,286	3	0.1	%
.13	Sodium Injection System	48,595	48,595	0	0.0	%
.14	Smith Stormwater Collection System	251,223	251,224	(1)	(0.0)	%
.15	Smith Waste Water Treatment Facility	35,800	35,802	(2)	(0.0)	%
.16	Daniel Ash Management Project	2,101,686	2,079,731	21,955	1.1	%
.17	Smith Water Conservation	16,251	16,253	(2)	(0.0)	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	17,818,659	17,944,006	(125,347)	(0.7)	%
.20	SPCC Compliance	126,250	128,006	(1,756)	(1.4)	%
.21	Crist Common FTIR Monitor	7,899	7,897	2	0.0	%
.22	Precipitator Upgrades for CAM Compliance	4,012,474	4,001,988	10,486	0.3	%
.23	Plant Groundwater Investigation	0	0	0	0.0	%
.24	Crist Water Conservation	59,899	38,538	21,361	55.4	%
.25	Crist Condenser Tubes	799,655	800,840	(1,185)	(0.1)	%
.26	CAIR/CAMR/CAVR Compliance	13,474,791	13,413,321	61,470	0.5	%
.27	General Water Quality	6,604	6,604	0	0.0	%
.28	Mercury Allowances	0	0	0	100.0	%
.29	Annual Nox Allowances	977,343	196,948	780,395	396.2	%
.30	Seasonal Nox Allowances	43,104	121,722	(78,618)	(64.6)	%
.31	SO2 Allowances	1,085,788	936,401	149,387	16.0	%
2	Total Investment Projects - Recoverable Costs	46,133,081	45,314,518	818,563	1.8	%
3	Recoverable Costs Allocated to Energy	42,778,646	3,317,168	39,461,478	1,189.6	%
4	Recoverable Costs Allocated to Demand	3,354,435	41,997,350	(38,642,915)	(92.0)	%

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-08-0775-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 7E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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 Amount	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	3,702	3,676	3,652	3,627	3,603	3,577	3,553	3,528	3,504	3,478	3,454	3,429	42,783	0	42,783
	.2 Crist 5, 6 & 7 Precipitator Projects	158,837	158,363	157,890	157,460	157,042	156,596	156,140	155,667	155,194	154,721	154,248	153,775	1,875,933	0	1,875,933
	.3 Crist 7 Flue Gas Conditioning	14,045	14,044	14,041	14,040	14,037	14,036	14,033	14,032	14,030	14,028	14,026	14,024	168,416	0	168,416
	.4 Low NOx Burners, Crist 6 & 7	169,536	169,307	169,078	168,849	168,620	168,391	168,162	167,934	167,704	167,475	167,247	167,018	2,019,321	0	2,019,321
	.5 CEMS - Plants Crist, Scholz, Smith, & Daniel	72,176	71,950	71,961	75,279	78,366	78,279	78,186	78,163	78,139	79,215	80,775	81,513	924,002	0	924,002
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	8,588	8,571	8,553	8,536	8,519	8,501	8,484	8,468	8,450	8,433	8,415	8,399	101,917	94,077	7,840
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,282	2,276	2,271	2,266	2,261	2,254	2,249	2,244	2,237	2,233	2,226	2,220	27,019	24,940	2,079
	.8 Crist Cooling Tower Cell	4,939	4,937	4,935	4,934	4,932	4,931	4,930	4,927	4,926	4,925	4,923	4,922	59,161	54,609	4,552
	.9 Crist 1-5 Dechlorination	2,315	2,307	2,300	2,292	2,284	2,276	2,269	2,261	2,253	2,246	2,238	2,230	27,271	25,173	2,098
	.10 Crist Diesel Fuel Oil Remediation	582	581	578	577	576	573	572	570	568	567	565	563	6,872	6,344	528
	.11 Crist Bulk Tanker Unload Sec Contain Struc	770	768	765	763	760	758	755	753	750	747	745	742	9,076	8,379	697
	.12 Crist IWW Sampling System	449	448	446	444	443	441	440	439	437	435	434	433	5,289	4,883	406
	.13 Sodium Injection System	4,100	4,091	4,082	4,073	4,063	4,054	4,045	4,036	4,027	4,017	4,008	3,999	48,595	0	48,595
	.14 Smith Stormwater Collection System	21,236	21,182	21,126	21,072	21,017	20,962	20,908	20,853	20,799	20,744	20,689	20,635	251,223	231,899	19,324
	.15 Smith Waste Water Treatment Facility	3,002	2,999	2,996	2,992	2,989	2,985	2,982	2,979	2,974	2,971	2,967	2,964	35,800	33,045	2,755
	.16 Daniel Ash Management Project	170,772	170,341	170,991	172,953	174,618	177,068	178,700	178,221	177,743	177,251	176,760	176,268	2,101,686	1,940,018	161,668
	.17 Smith Water Conservation	1,369	1,366	1,364	1,361	1,358	1,356	1,353	1,350	1,348	1,345	1,342	1,339	16,251	15,001	1,250
	.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	1,499,307	1,497,442	1,496,511	1,493,487	1,490,774	1,488,340	1,484,655	1,480,981	1,477,304	1,473,629	1,469,953	1,466,276	17,818,659	0	17,818,659
	.20 SPCC Compliance	10,553	10,530	10,553	10,576	10,552	10,530	10,517	10,503	10,479	10,456	10,469	10,532	126,250	116,538	9,712
	.21 Crist Common FTIR Monitor	667	665	664	662	661	659	657	656	655	652	651	650	7,899	0	7,899
	.22 Precipitator Upgrades for CAM Compliance	338,031	337,366	336,701	336,036	335,371	334,706	334,040	333,375	332,710	332,045	331,379	330,714	4,012,474	0	4,012,474
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	1,076	1,073	1,070	1,068	1,065	1,063	1,061	1,059	1,056	1,054	1,051	48,203	59,899	55,291	4,608
	.25 Crist Condenser Tubes	67,496	67,347	67,157	67,006	66,856	66,706	66,556	66,407	66,256	66,106	65,956	65,806	799,655	738,142	61,513
	.26 CAIR/CAMR/CAVR Compliance	761,583	760,846	765,411	805,850	848,846	877,137	901,690	904,610	905,601	905,965	910,509	4,126,743	13,474,791	0	13,474,791
	.27 General Water Quality	571	567	563	560	556	552	548	544	541	538	534	530	6,604	6,096	508
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual Nox Allowances	0	33,094	87,077	105,853	104,934	118,813	130,886	119,105	97,593	78,436	60,363	41,189	977,343	0	977,343
	.30 Seasonal Nox Allowances	0	0	4,820	9,688	8,877	7,258	5,496	3,493	1,564	636	636	636	43,104	0	43,104
	.31 SO2 Allowances	63,817	62,445	61,169	59,307	56,682	95,485	131,840	123,821	116,002	110,015	105,440	99,765	1,085,788	0	1,085,788
2	Total Investment Projects - Recoverable Costs	3,381,801	3,408,582	3,468,725	3,531,611	3,570,662	3,648,287	3,715,707	3,690,979	3,654,844	3,624,363	3,602,003	6,835,517	46,133,081	3,354,435	42,778,646
3	Recoverable Costs Allocated to Energy	3,108,572	3,136,005	3,195,798	3,257,087	3,294,860	3,370,480	3,436,639	3,412,598	3,377,169	3,347,394	3,325,714	6,516,330	42,778,646		
4	Recoverable Costs Allocated to Demand	273,229	272,577	272,927	274,524	275,802	277,807	279,068	278,381	277,675	276,969	276,289	319,187	3,354,435		
5	Retail Energy Jurisdictional Factor	0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (B)	2,997,807	3,025,657	3,090,132	3,156,403	3,191,971	3,267,293	3,328,372	3,302,596	3,268,769	3,234,333	3,207,782	6,287,903	41,359,018		
8	Jurisdictional Demand Recoverable Costs (C)	263,452	262,823	263,161	264,700	265,933	267,866	269,082	268,419	267,739	267,058	266,402	307,765	3,234,400		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	3,261,259	3,288,480	3,353,293	3,421,103	3,457,904	3,535,159	3,597,454	3,571,015	3,536,508	3,501,391	3,474,184	6,595,668	44,593,418		

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 2009 - December 2009

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)	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	
3	Less: Accumulated Depreciation (C)	(104,682)	(107,305)	(109,928)	(112,551)	(115,174)	(117,797)	(120,420)	(123,043)	(125,666)	(128,289)	(130,912)	(133,535)	(136,158)	
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)	115,612	112,989	110,366	107,743	105,120	102,497	99,874	97,251	94,628	92,005	89,382	86,759	84,136	
6	Average Net Investment		114,301	111,678	109,055	106,432	103,809	101,186	98,563	95,940	93,317	90,694	88,071	85,448	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		840	820	801	782	763	743	724	705	686	666	647	628	8,805
	b Debt Component (Line 6 x Debt Component x 1/12)		239	233	228	222	217	211	206	200	195	189	184	178	2,502
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	31,476
	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)		3,702	3,676	3,652	3,627	3,603	3,577	3,553	3,528	3,504	3,478	3,454	3,429	42,783
	a Recoverable Costs Allocated to Energy		3,702	3,676	3,652	3,627	3,603	3,577	3,553	3,528	3,504	3,478	3,454	3,429	42,783
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,570	3,547	3,531	3,515	3,490	3,467	3,441	3,414	3,392	3,361	3,332	3,309	41,369
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)		3,570	3,547	3,531	3,515	3,490	3,467	3,441	3,414	3,392	3,361	3,332	3,309	41,369

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 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
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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		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	8,988	2,545	3,452	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)	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	
3	Less: Accumulated Depreciation (C)	(2,984,218)	(3,034,350)	(3,084,482)	(3,134,614)	(3,175,758)	(3,223,345)	(3,270,025)	(3,320,157)	(3,370,289)	(3,420,421)	(3,470,553)	(3,520,685)	(3,570,817)	
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)	11,547,661	11,497,529	11,447,397	11,397,265	11,356,121	11,308,534	11,261,854	11,211,722	11,161,590	11,111,458	11,061,326	11,011,194	10,961,062	
6	Average Net Investment		11,522,595	11,472,463	11,422,331	11,376,693	11,332,328	11,285,194	11,236,788	11,186,656	11,136,524	11,086,392	11,036,260	10,986,128	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		84,657	84,288	83,920	83,585	83,259	82,912	82,557	82,188	81,820	81,452	81,083	80,715	992,436
	b Debt Component (Line 6 x Debt Component x 1/12)		24,048	23,943	23,838	23,743	23,651	23,552	23,451	23,347	23,242	23,137	23,033	22,928	281,913
8	Investment Expenses														
	a Depreciation (E)		38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	465,084
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	136,500
	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)		158,837	158,363	157,890	157,460	157,042	156,596	156,140	155,667	155,194	154,721	154,248	153,775	1,875,933
	a Recoverable Costs Allocated to Energy		158,837	158,363	157,890	157,460	157,042	156,596	156,140	155,667	155,194	154,721	154,248	153,775	1,875,933
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		153,177	152,791	152,670	152,594	152,138	151,802	151,221	150,649	150,213	149,495	148,778	148,384	1,813,912
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)		153,177	152,791	152,670	152,594	152,138	151,802	151,221	150,649	150,213	149,495	148,778	148,384	1,813,912

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	1,467,272	1,467,068	1,466,864	1,466,660	1,466,456	1,466,252	1,466,048	1,465,844	1,465,640	1,465,436	1,465,232	1,465,028	1,464,824	
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)	1,467,272	1,467,068	1,466,864	1,466,660	1,466,456	1,466,252	1,466,048	1,465,844	1,465,640	1,465,436	1,465,232	1,465,028	1,464,824	
6	Average Net Investment		1,467,170	1,466,966	1,466,762	1,466,558	1,466,354	1,466,150	1,465,946	1,465,742	1,465,538	1,465,334	1,465,130	1,464,926	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,779	10,778	10,776	10,775	10,773	10,772	10,770	10,769	10,767	10,766	10,764	10,763	129,252
	b Debt Component (Line 6 x Debt Component x 1/12)		3,062	3,062	3,061	3,061	3,060	3,060	3,059	3,059	3,059	3,058	3,058	3,057	36,716
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		204	204	204	204	204	204	204	204	204	204	204	204	2,448
	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)		14,045	14,044	14,041	14,040	14,037	14,036	14,033	14,032	14,030	14,028	14,026	14,024	168,416
	a Recoverable Costs Allocated to Energy		14,045	14,044	14,041	14,040	14,037	14,036	14,033	14,032	14,030	14,028	14,026	14,024	168,416
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,545	13,550	13,577	13,606	13,599	13,606	13,591	13,580	13,580	13,554	13,529	13,532	162,849
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)		13,545	13,550	13,577	13,606	13,599	13,606	13,591	13,580	13,580	13,554	13,529	13,532	162,849

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	
3	Less: Accumulated Depreciation (C)	6,312,945	6,288,681	6,264,417	6,240,153	6,215,889	6,191,625	6,167,361	6,143,097	6,118,833	6,094,569	6,070,305	6,046,041	6,021,777	
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)	15,410,868	15,386,604	15,362,340	15,338,076	15,313,812	15,289,548	15,265,284	15,241,020	15,216,756	15,192,492	15,168,228	15,143,964	15,119,700	
6	Average Net Investment		15,398,736	15,374,472	15,350,208	15,325,944	15,301,680	15,277,416	15,253,152	15,228,888	15,204,624	15,180,360	15,156,096	15,131,832	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		113,135	112,956	112,778	112,600	112,421	112,243	112,065	111,887	111,708	111,530	111,352	111,174	1,345,849
	b Debt Component (Line 6 x Debt Component x 1/12)		32,137	32,087	32,036	31,985	31,935	31,884	31,833	31,783	31,732	31,681	31,631	31,580	382,304
8	Investment Expenses														
	a Depreciation (E)		24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	291,168
	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)		169,536	169,307	169,078	168,849	168,620	168,391	168,162	167,934	167,704	167,475	167,247	167,018	2,019,321
	a Recoverable Costs Allocated to Energy		169,536	169,307	169,078	168,849	168,620	168,391	168,162	167,934	167,704	167,475	167,247	167,018	2,019,321
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		163,495	163,350	163,488	163,630	163,354	163,236	162,864	162,521	162,321	161,818	161,316	161,163	1,952,556
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)		163,495	163,350	163,488	163,630	163,354	163,236	162,864	162,521	162,321	161,818	161,316	161,163	1,952,556

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1001, 1154, 1164, 1217, 1240, 1245, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 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		360	5,068	62,641	556,604	1,553	6,730	250	18,250	250	252,666	103,404	0	
	b Clearings to Plant		360	5,068	62,641	556,604	1,553	6,730	250	18,250	250	65,000	0	291,070	
	c Retirements		0	125,636	110,727	0	0	0	0	0	0	59,148	0	0	
	d Cost of Removal		0	0	1,008	1	0	(1)	0	0	0	2,000	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	5,047,801	5,048,161	4,927,594	4,879,508	5,436,112	5,437,664	5,444,394	5,444,644	5,462,894	5,463,144	5,468,996	5,468,996	5,760,066	
3	Less: Accumulated Depreciation (C)	1,033,395	1,019,886	1,132,137	1,230,674	1,216,959	1,202,657	1,188,345	1,174,025	1,159,680	1,145,311	1,192,081	1,177,696	1,162,923	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	187,666	291,070	0	
5	Net Investment (Lines 2 + 3 + 4)	6,081,196	6,068,047	6,059,730	6,110,182	6,653,071	6,640,322	6,632,740	6,618,670	6,622,575	6,608,456	6,848,744	6,937,763	6,922,990	
6	Average Net Investment		6,074,622	6,063,889	6,084,956	6,381,626	6,646,696	6,636,531	6,625,705	6,620,622	6,615,515	6,728,600	6,893,253	6,930,376	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		44,630	44,551	44,706	46,886	48,833	48,759	48,679	48,642	48,604	49,435	50,645	50,917	575,287
	b Debt Component (Line 6 x Debt Component x 1/12)		12,678	12,655	12,699	13,318	13,872	13,850	13,828	13,817	13,807	14,043	14,386	14,464	163,417
8	Investment Expenses														
	a Depreciation (E)		13,377	13,253	13,065	13,584	14,170	14,179	14,188	14,213	14,237	14,246	14,253	14,641	167,406
	b Amortization (F)		132	132	132	132	132	132	132	132	132	132	132	132	1,584
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	16,308
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		72,176	71,950	71,961	75,279	78,366	78,279	78,186	78,163	78,139	79,215	80,775	81,513	924,002
	a Recoverable Costs Allocated to Energy		72,176	71,950	71,961	75,279	78,366	78,279	78,186	78,163	78,139	79,215	80,775	81,513	924,002
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		69,604	69,418	69,582	72,952	75,919	75,883	75,723	75,643	75,631	76,539	77,911	78,656	893,461
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)		69,604	69,418	69,582	72,952	75,919	75,883	75,723	75,643	75,631	76,539	77,911	78,656	893,461

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,232,602; Scholz $916,802 Smith $1,317,122; Daniel $581,275. Ending Balances: Crist, $2,521,810; Scholz $916,802; Smith $1,740,179; Daniel $581,275.
(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: 3.2%; Smith 2.5%; Scholz 4.2%; Daniel 3.1% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	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)	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)	(201,338)	(203,174)	(205,010)	(206,846)	(208,682)	(210,518)	(212,354)	(214,190)	(216,026)	(217,862)	(219,698)	(221,534)	(223,370)	
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)	716,686	714,850	713,014	711,178	709,342	707,506	705,670	703,834	701,998	700,162	698,326	696,490	694,654	
6	Average Net Investment		715,769	713,933	712,097	710,261	708,425	706,589	704,753	702,917	701,081	699,245	697,409	695,573	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,259	5,245	5,232	5,218	5,205	5,191	5,178	5,164	5,151	5,137	5,124	5,110	62,214
	b Debt Component (Line 6 x Debt Component x 1/12)		1,494	1,490	1,486	1,482	1,478	1,475	1,471	1,467	1,463	1,459	1,455	1,452	17,672
8	Investment Expenses														
	a Depreciation (E)		1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,835	22,031
	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)		8,588	8,571	8,553	8,536	8,519	8,501	8,484	8,468	8,450	8,433	8,415	8,399	101,917
	a Recoverable Costs Allocated to Energy		661	659	657	656	656	654	653	651	650	649	648	646	7,840
	b Recoverable Costs Allocated to Demand		7,927	7,912	7,896	7,880	7,863	7,847	7,831	7,817	7,800	7,784	7,767	7,753	94,077
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		637	636	635	636	636	634	632	630	629	627	625	623	7,580
13	Retail Demand-Related Recoverable Costs (I)		7,643	7,629	7,613	7,598	7,582	7,566	7,551	7,537	7,521	7,505	7,489	7,476	90,710
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,280	8,265	8,248	8,234	8,218	8,200	8,183	8,167	8,150	8,132	8,114	8,099	98,290

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 2.4% annually, PEs 3400 and 3412 depreciable at 2.4% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	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)	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	
3	Less: Accumulated Depreciation (C)	(63,696)	(64,290)	(64,884)	(65,478)	(66,072)	(66,666)	(67,260)	(67,854)	(68,448)	(69,042)	(69,636)	(70,230)	(70,823)	
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)	179,276	178,682	178,088	177,494	176,900	176,306	175,712	175,118	174,524	173,930	173,336	172,742	172,149	
6	Average Net Investment		178,979	178,385	177,791	177,197	176,603	176,009	175,415	174,821	174,227	173,633	173,039	172,446	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,315	1,310	1,306	1,302	1,298	1,293	1,289	1,285	1,280	1,276	1,271	1,267	15,492
	b Debt Component (Line 6 x Debt Component x 1/12)		373	372	371	370	369	367	366	365	363	363	361	360	4,400
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	594	594	594	594	594	594	594	593	7,127
	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)		2,282	2,276	2,271	2,266	2,261	2,254	2,249	2,244	2,237	2,233	2,226	2,220	27,019
	a Recoverable Costs Allocated to Energy		175	175	175	175	174	173	173	172	172	172	172	171	2,079
	b Recoverable Costs Allocated to Demand		2,107	2,101	2,096	2,091	2,087	2,081	2,076	2,072	2,065	2,061	2,054	2,049	24,940
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		169	169	169	170	169	168	168	166	166	166	166	165	2,011
13	Retail Demand-Related Recoverable Costs (I)		2,032	2,026	2,021	2,016	2,012	2,007	2,002	1,998	1,991	1,987	1,980	1,976	24,048
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,201	2,195	2,190	2,186	2,181	2,175	2,170	2,164	2,157	2,153	2,146	2,141	26,059

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,949; 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 3.2%; Smith 2.5% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	506,368	506,206	506,044	505,882	505,720	505,558	505,396	505,234	505,072	504,910	504,748	504,586	504,424	
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)	506,368	506,206	506,044	505,882	505,720	505,558	505,396	505,234	505,072	504,910	504,748	504,586	504,424	
6	Average Net Investment		506,287	506,125	505,963	505,801	505,639	505,477	505,315	505,153	504,991	504,829	504,667	504,505	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,720	3,719	3,717	3,716	3,715	3,714	3,713	3,711	3,710	3,709	3,708	3,707	44,559
	b Debt Component (Line 6 x Debt Component x 1/12)		1,057	1,056	1,056	1,056	1,055	1,055	1,055	1,054	1,054	1,054	1,053	1,053	12,658
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		162	162	162	162	162	162	162	162	162	162	162	162	1,944
	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)		4,939	4,937	4,935	4,934	4,932	4,931	4,930	4,927	4,926	4,925	4,923	4,922	59,161
	a Recoverable Costs Allocated to Energy		380	380	380	380	379	379	379	379	379	379	379	379	4,552
	b Recoverable Costs Allocated to Demand		4,559	4,557	4,555	4,554	4,553	4,552	4,551	4,548	4,547	4,546	4,544	4,543	54,609
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		366	367	367	368	367	367	367	367	367	366	366	366	4,401
13	Retail Demand-Related Recoverable Costs (I)		4,396	4,394	4,392	4,391	4,390	4,389	4,388	4,385	4,384	4,383	4,381	4,380	52,653
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,762	4,761	4,759	4,759	4,757	4,756	4,755	4,752	4,751	4,749	4,747	4,746	57,054

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 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		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)	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)	(145,859)	(146,673)	(147,487)	(148,301)	(149,115)	(149,929)	(150,743)	(151,557)	(152,371)	(153,185)	(153,999)	(154,813)	(155,627)	
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)	159,464	158,650	157,836	157,022	156,208	155,394	154,580	153,766	152,952	152,138	151,324	150,510	149,696	
6	Average Net Investment		159,057	158,243	157,429	156,615	155,801	154,987	154,173	153,359	152,545	151,731	150,917	150,103	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,169	1,163	1,157	1,151	1,145	1,139	1,133	1,127	1,121	1,115	1,109	1,103	13,632
	b Debt Component (Line 6 x Debt Component x 1/12)		332	330	329	327	325	323	322	320	318	317	315	313	3,871
8	Investment Expenses														
	a Depreciation (E)		814	814	814	814	814	814	814	814	814	814	814	814	9,768
	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)		2,315	2,307	2,300	2,292	2,284	2,276	2,269	2,261	2,253	2,246	2,238	2,230	27,271
	a Recoverable Costs Allocated to Energy		178	177	177	176	176	175	175	174	173	173	172	172	2,098
	b Recoverable Costs Allocated to Demand		2,137	2,130	2,123	2,116	2,108	2,101	2,094	2,087	2,080	2,073	2,066	2,058	25,173
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		172	171	171	171	171	170	169	168	167	167	166	166	2,029
13	Retail Demand-Related Recoverable Costs (I)		2,061	2,054	2,047	2,040	2,033	2,026	2,019	2,012	2,006	1,999	1,992	1,984	24,273
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,233	2,225	2,218	2,211	2,204	2,196	2,188	2,180	2,173	2,166	2,158	2,150	26,302

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	(26,624)	(26,808)	(26,992)	(27,176)	(27,360)	(27,544)	(27,728)	(27,912)	(28,096)	(28,280)	(28,464)	(28,648)	(28,832)	
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)	42,299	42,115	41,931	41,747	41,563	41,379	41,195	41,011	40,827	40,643	40,459	40,275	40,091	
6	Average Net Investment		42,207	42,023	41,839	41,655	41,471	41,287	41,103	40,919	40,735	40,551	40,367	40,183	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		310	309	307	306	305	303	302	301	299	298	297	295	3,632
	b Debt Component (Line 6 x Debt Component x 1/12)		88	88	87	87	87	86	86	85	85	85	84	84	1,032
8	Investment Expenses														
	a Depreciation (E)		184	184	184	184	184	184	184	184	184	184	184	184	2,208
	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)		582	581	578	577	576	573	572	570	568	567	565	563	6,872
	a Recoverable Costs Allocated to Energy		45	45	44	44	44	44	44	44	44	44	43	43	528
	b Recoverable Costs Allocated to Demand		537	536	534	533	532	529	528	526	524	523	522	520	6,344
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		43	43	43	43	43	43	43	43	43	43	41	41	512
13	Retail Demand-Related Recoverable Costs (I)		518	517	515	514	513	510	509	507	505	504	503	501	6,116
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		561	560	558	557	556	553	552	550	548	547	544	542	6,628

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	(48,419)	(48,690)	(48,961)	(49,232)	(49,503)	(49,774)	(50,045)	(50,316)	(50,587)	(50,858)	(51,129)	(51,400)	(51,671)	
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)	53,076	52,805	52,534	52,263	51,992	51,721	51,450	51,179	50,908	50,637	50,366	50,095	49,824	
6	Average Net Investment		52,941	52,670	52,399	52,128	51,857	51,586	51,315	51,044	50,773	50,502	50,231	49,960	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		389	387	385	383	381	379	377	375	373	371	369	367	4,536
	b Debt Component (Line 6 x Debt Component x 1/12)		110	110	109	109	108	108	107	107	106	105	105	104	1,288
8	Investment Expenses														
	a Depreciation (E)		271	271	271	271	271	271	271	271	271	271	271	271	3,252
	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)		770	768	765	763	760	758	755	753	750	747	745	742	9,076
	a Recoverable Costs Allocated to Energy		59	59	59	59	58	58	58	58	58	57	57	57	697
	b Recoverable Costs Allocated to Demand		711	709	706	704	702	700	697	695	692	690	688	685	8,379
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		57	57	57	57	56	56	56	56	56	55	55	55	673
13	Retail Demand-Related Recoverable Costs (I)		686	684	681	679	677	675	672	670	667	665	663	660	8,079
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		743	741	738	736	733	731	728	726	723	720	718	715	8,752

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	(28,724)	(28,883)	(29,042)	(29,201)	(29,360)	(29,519)	(29,678)	(29,837)	(29,996)	(30,155)	(30,314)	(30,473)	(30,632)	
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)	30,819	30,660	30,501	30,342	30,183	30,024	29,865	29,706	29,547	29,388	29,229	29,070	28,911	
6	Average Net Investment		30,740	30,581	30,422	30,263	30,104	29,945	29,786	29,627	29,468	29,309	29,150	28,991	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		226	225	224	222	221	220	219	218	217	215	214	213	2,634
	b Debt Component (Line 6 x Debt Component x 1/12)		64	64	63	63	63	62	62	62	61	61	61	61	747
8	Investment Expenses														
	a Depreciation (E)		159	159	159	159	159	159	159	159	159	159	159	159	1,908
	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)		449	448	446	444	443	441	440	439	437	435	434	433	5,289
	a Recoverable Costs Allocated to Energy		35	34	34	34	34	34	34	34	34	33	33	33	406
	b Recoverable Costs Allocated to Demand		414	414	412	410	409	407	406	405	403	402	401	400	4,883
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		34	33	33	33	33	33	33	33	33	32	32	32	394
13	Retail Demand-Related Recoverable Costs (I)		399	399	397	395	394	392	391	391	389	388	387	386	4,708
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		433	432	430	428	427	425	424	424	422	420	419	418	5,102

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	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)	(59,991)	(60,972)	(61,953)	(62,934)	(63,915)	(64,896)	(65,877)	(66,858)	(67,839)	(68,820)	(69,801)	(70,782)	(71,763)	
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)	331,128	330,147	329,166	328,185	327,204	326,223	325,242	324,261	323,280	322,299	321,318	320,337	319,356	
6	Average Net Investment		330,638	329,657	328,676	327,695	326,714	325,733	324,752	323,771	322,790	321,809	320,828	319,847	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,429	2,422	2,415	2,408	2,400	2,393	2,386	2,379	2,372	2,364	2,357	2,350	28,675
	b Debt Component (Line 6 x Debt Component x 1/12)		690	688	686	684	682	680	678	676	674	672	670	668	8,148
8	Investment Expenses														
	a Depreciation (E)		981	981	981	981	981	981	981	981	981	981	981	981	11,772
	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)		4,100	4,091	4,082	4,073	4,063	4,054	4,045	4,036	4,027	4,017	4,008	3,999	48,595
	a Recoverable Costs Allocated to Energy		4,100	4,091	4,082	4,073	4,063	4,054	4,045	4,036	4,027	4,017	4,008	3,999	48,595
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,954	3,947	3,947	3,947	3,936	3,930	3,918	3,906	3,898	3,881	3,866	3,859	46,989
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)		3,954	3,947	3,947	3,947	3,936	3,930	3,918	3,906	3,898	3,881	3,866	3,859	46,989

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 3.2% annually; Smith 2.5% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	(1,143,071)	(1,148,867)	(1,154,663)	(1,160,459)	(1,166,255)	(1,172,051)	(1,177,847)	(1,183,643)	(1,189,439)	(1,195,235)	(1,201,031)	(1,206,827)	(1,212,623)	
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)	1,639,529	1,633,733	1,627,937	1,622,141	1,616,345	1,610,549	1,604,753	1,598,957	1,593,161	1,587,365	1,581,569	1,575,773	1,569,977	
6	Average Net Investment		1,636,631	1,630,835	1,625,039	1,619,243	1,613,447	1,607,651	1,601,855	1,596,059	1,590,263	1,584,467	1,578,671	1,572,875	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		12,024	11,982	11,939	11,897	11,854	11,811	11,769	11,726	11,684	11,641	11,598	11,556	141,481
	b Debt Component (Line 6 x Debt Component x 1/12)		3,416	3,404	3,391	3,379	3,367	3,355	3,343	3,331	3,319	3,307	3,295	3,283	40,190
8	Investment Expenses														
	a Depreciation (E)		5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	69,552
	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)		21,236	21,182	21,126	21,072	21,017	20,962	20,908	20,853	20,799	20,744	20,689	20,635	251,223
	a Recoverable Costs Allocated to Energy		1,634	1,629	1,625	1,621	1,617	1,612	1,608	1,604	1,600	1,596	1,591	1,587	19,324
	b Recoverable Costs Allocated to Demand		19,602	19,553	19,501	19,451	19,400	19,350	19,300	19,249	19,199	19,148	19,098	19,048	231,899
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,576	1,572	1,571	1,571	1,567	1,563	1,557	1,552	1,549	1,542	1,535	1,531	18,686
13	Retail Demand-Related Recoverable Costs (I)		18,901	18,853	18,803	18,755	18,706	18,658	18,609	18,560	18,512	18,463	18,415	18,366	223,601
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		20,477	20,425	20,374	20,326	20,273	20,221	20,166	20,112	20,061	20,005	19,950	19,897	242,287

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) 2.5% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	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)	100,003	99,630	99,257	98,884	98,511	98,138	97,765	97,392	97,019	96,646	96,273	95,900	95,527	
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)	278,965	278,592	278,219	277,846	277,473	277,100	276,727	276,354	275,981	275,608	275,235	274,862	274,489	
6	Average Net Investment		278,779	278,406	278,033	277,660	277,287	276,914	276,541	276,168	275,795	275,422	275,049	274,676	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,048	2,045	2,043	2,040	2,037	2,034	2,032	2,029	2,026	2,024	2,020	2,018	24,396
	b Debt Component (Line 6 x Debt Component x 1/12)		581	581	580	579	579	578	577	577	575	574	574	573	6,928
8	Investment Expenses														
	a Depreciation (E)		373	373	373	373	373	373	373	373	373	373	373	373	4,476
	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)		3,002	2,999	2,996	2,992	2,989	2,985	2,982	2,979	2,974	2,971	2,967	2,964	35,800
	a Recoverable Costs Allocated to Energy		231	231	230	230	230	230	229	229	229	229	229	228	2,755
	b Recoverable Costs Allocated to Demand		2,771	2,768	2,766	2,762	2,759	2,755	2,753	2,750	2,745	2,742	2,738	2,736	33,045
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		223	223	222	223	223	223	222	222	222	221	221	220	2,665
13	Retail Demand-Related Recoverable Costs (I)		2,672	2,669	2,667	2,663	2,660	2,656	2,654	2,652	2,647	2,644	2,640	2,638	31,862
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,895	2,892	2,889	2,886	2,883	2,879	2,876	2,874	2,869	2,865	2,861	2,858	34,527

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) Smith 2.5% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 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	2,900	(2,900)	0	(2,900)	0	2,900	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	970	11,058	0	0	0	0	0	0	0	
	d Cost of Removal		7,538	5,450	233,811	286,751	176,570	453,091	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)	16,204,251	16,204,251	16,204,251	16,204,251	16,203,281	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	
3	Less: Accumulated Depreciation (C)	(6,500,495)	(6,545,124)	(6,591,841)	(6,410,197)	(6,174,643)	(6,039,166)	(5,638,211)	(5,690,347)	(5,742,483)	(5,794,619)	(5,846,755)	(5,898,891)	(5,951,027)	
4	CWIP - Non Interest Bearing	0	0	0	2,900	0	0	(2,900)	(2,900)	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	9,703,756	9,659,127	9,612,410	9,796,954	10,028,639	10,153,058	10,551,113	10,498,977	10,449,741	10,397,605	10,345,469	10,293,333	10,241,197	
6	Average Net Investment		9,681,441	9,635,768	9,704,682	9,912,796	10,090,848	10,352,085	10,525,045	10,474,359	10,423,673	10,371,537	10,319,401	10,267,265	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		71,130	70,794	71,300	72,829	74,137	76,057	77,328	76,955	76,583	76,200	75,817	75,434	894,564
	b Debt Component (Line 6 x Debt Component x 1/12)		20,205	20,110	20,254	20,688	21,060	21,605	21,966	21,860	21,754	21,645	21,537	21,428	254,112
8	Investment Expenses														
	a Depreciation (E)		41,855	41,855	41,855	41,854	41,839	41,824	41,824	41,824	41,824	41,824	41,824	41,824	502,026
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	123,744
	d Property Taxes		27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	327,240
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		170,772	170,341	170,991	172,953	174,618	177,068	178,700	178,221	177,743	177,251	176,760	176,268	2,101,686
	a Recoverable Costs Allocated to Energy		13,136	13,103	13,153	13,304	13,432	13,621	13,746	13,709	13,673	13,635	13,597	13,559	161,668
	b Recoverable Costs Allocated to Demand		157,636	157,238	157,838	159,649	161,186	163,447	164,954	164,512	164,070	163,616	163,163	162,709	1,940,018
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		12,668	12,642	12,718	12,893	13,013	13,204	13,313	13,267	13,234	13,174	13,115	13,084	156,325
13	Retail Demand-Related Recoverable Costs (I)		151,995	151,611	152,190	153,936	155,418	157,598	159,051	158,625	158,199	157,761	157,324	156,887	1,870,595
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		164,663	164,253	164,908	166,829	168,431	170,802	172,364	171,892	171,433	170,935	170,439	169,971	2,026,920

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) 3.1% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 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)	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	
3	Less: Accumulated Depreciation (C)	(18,567)	(18,847)	(19,127)	(19,407)	(19,687)	(19,967)	(20,247)	(20,527)	(20,807)	(21,087)	(21,367)	(21,647)	(21,927)	
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)	115,566	115,286	115,006	114,726	114,446	114,166	113,886	113,606	113,326	113,046	112,766	112,486	112,206	
6	Average Net Investment		115,426	115,146	114,866	114,586	114,306	114,026	113,746	113,466	113,186	112,906	112,626	112,346	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		848	846	844	842	839	838	836	833	831	830	827	825	10,039
	b Debt Component (Line 6 x Debt Component x 1/12)		241	240	240	239	239	238	237	237	237	235	235	234	2,852
8	Investment Expenses														
	a Depreciation (E)		280	280	280	280	280	280	280	280	280	280	280	280	3,360
	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)		1,369	1,366	1,364	1,361	1,358	1,356	1,353	1,350	1,348	1,345	1,342	1,339	16,251
	a Recoverable Costs Allocated to Energy		106	106	104	104	104	104	104	104	104	104	103	103	1,250
	b Recoverable Costs Allocated to Demand		1,263	1,260	1,260	1,257	1,254	1,252	1,249	1,246	1,244	1,241	1,239	1,236	15,001
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		102	102	101	101	101	101	101	101	101	100	99	99	1,209
13	Retail Demand-Related Recoverable Costs (I)		1,218	1,215	1,215	1,212	1,209	1,207	1,204	1,201	1,199	1,197	1,195	1,192	14,464
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,320	1,317	1,316	1,313	1,310	1,308	1,305	1,302	1,300	1,297	1,294	1,291	15,673

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) 2.5% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	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		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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 Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 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	382,521	198,107	(123,127)	145,955	1,457	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	1,554,232	1,457	(3)	0	0	0	0	0	
	c Retirements		0	0	0	0	1,195,516	123,904	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	61,933	17,537	31,647	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)	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,803,563	134,681,116	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	
3	Less: Accumulated Depreciation (C)	(17,511,485)	(17,900,508)	(18,289,531)	(18,678,554)	(19,005,644)	(18,182,093)	(18,416,359)	(18,806,012)	(19,195,665)	(19,585,318)	(19,974,971)	(20,364,624)	(20,754,277)	
4	CWIP - Non Interest Bearing	950,774	950,774	1,333,295	1,531,402	1,408,275	(3)	(3)	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	117,884,136	117,495,113	117,488,611	117,297,694	116,847,477	116,621,467	116,264,754	115,875,101	115,485,448	115,095,795	114,706,142	114,316,489	113,926,836	
6	Average Net Investment		117,689,624	117,491,862	117,393,153	117,072,586	116,734,472	116,443,111	116,069,927	115,680,274	115,290,621	114,900,968	114,511,315	114,121,662	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		864,666	863,213	862,488	860,133	857,648	855,507	852,765	849,903	847,040	844,177	841,315	838,451	10,237,306
	b Debt Component (Line 6 x Debt Component x 1/12)		245,618	245,206	245,000	244,331	243,624	243,016	242,237	241,425	240,611	239,799	238,985	238,172	2,908,024
8	Investment Expenses														
	a Depreciation (E)		358,051	358,051	358,051	358,051	358,530	358,845	358,681	358,681	358,681	358,681	358,681	358,681	4,301,665
	b Amortization (F)		2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	27,504
	c Dismantlement		28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	344,160
	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)		1,499,307	1,497,442	1,496,511	1,493,487	1,490,774	1,488,340	1,484,655	1,480,981	1,477,304	1,473,629	1,469,953	1,466,276	17,818,659
	a Recoverable Costs Allocated to Energy		1,499,307	1,497,442	1,496,511	1,493,487	1,490,774	1,488,340	1,484,655	1,480,981	1,477,304	1,473,629	1,469,953	1,466,276	17,818,659
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,445,884	1,444,751	1,447,030	1,447,320	1,444,222	1,442,775	1,437,883	1,433,243	1,429,886	1,423,856	1,417,827	1,414,876	17,229,553
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)		1,445,884	1,444,751	1,447,030	1,447,320	1,444,222	1,442,775	1,437,883	1,433,243	1,429,886	1,423,856	1,417,827	1,414,876	17,229,553

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) Crist: 3.2% annually
(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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	9,873	(133)	25	61	0	0	0	0	7,587	7,587	
	b Clearings to Plant		0	0	0	0	0	0	9,826	0	0	0	0	15,174	
	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)	919,836	919,836	919,836	919,836	919,836	919,836	919,836	929,662	929,662	929,662	929,662	929,662	944,836	
3	Less: Accumulated Depreciation (C)	(60,068)	(62,521)	(64,974)	(67,427)	(69,880)	(72,333)	(74,786)	(77,249)	(79,722)	(82,195)	(84,668)	(87,141)	(89,630)	
4	CWIP - Non Interest Bearing	0	0	0	9,873	9,740	9,765	9,826	0	0	0	0	7,587	0	
5	Net Investment (Lines 2 + 3 + 4)	859,768	857,315	854,862	862,282	859,696	857,268	854,876	852,413	849,940	847,467	844,994	850,108	855,206	
6	Average Net Investment		858,542	856,089	858,572	860,989	858,482	856,072	853,644	851,176	848,703	846,230	847,551	852,657	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,308	6,290	6,308	6,326	6,307	6,290	6,272	6,254	6,235	6,217	6,227	6,264	75,298
	b Debt Component (Line 6 x Debt Component x 1/12)		1,792	1,787	1,792	1,797	1,792	1,787	1,782	1,776	1,771	1,766	1,769	1,779	21,390
8	Investment Expenses														
	a Depreciation (E)		2,453	2,453	2,453	2,453	2,453	2,453	2,463	2,473	2,473	2,473	2,473	2,489	29,562
	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)		10,553	10,530	10,553	10,576	10,552	10,530	10,517	10,503	10,479	10,456	10,469	10,532	126,250
	a Recoverable Costs Allocated to Energy		812	810	812	814	812	810	809	808	806	804	805	810	9,712
	b Recoverable Costs Allocated to Demand		9,741	9,720	9,741	9,762	9,740	9,720	9,708	9,695	9,673	9,652	9,664	9,722	116,538
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		783	781	785	789	787	785	784	782	780	777	776	782	9,391
13	Retail Demand-Related Recoverable Costs (I)		9,392	9,372	9,392	9,413	9,391	9,372	9,361	9,348	9,327	9,307	9,318	9,374	112,367
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,175	10,153	10,177	10,202	10,178	10,157	10,145	10,130	10,107	10,084	10,094	10,156	121,758

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $919,836; Smith $0. Ending Balances: Crist, $919,836; Smith $25,000.
(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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	(9,907)	(10,075)	(10,243)	(10,411)	(10,579)	(10,747)	(10,915)	(11,083)	(11,251)	(11,419)	(11,587)	(11,755)	(11,923)	
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)	52,963	52,795	52,627	52,459	52,291	52,123	51,955	51,787	51,619	51,451	51,283	51,115	50,947	
6	Average Net Investment		52,879	52,711	52,543	52,375	52,207	52,039	51,871	51,703	51,535	51,367	51,199	51,031	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		389	387	386	385	384	382	381	380	379	377	376	375	4,581
	b Debt Component (Line 6 x Debt Component x 1/12)		110	110	110	109	109	109	108	108	108	107	107	107	1,302
8	Investment Expenses														
	a Depreciation (E)		168	168	168	168	168	168	168	168	168	168	168	168	2,016
	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)		667	665	664	662	661	659	657	656	655	652	651	650	7,899
	a Recoverable Costs Allocated to Energy		667	665	664	662	661	659	657	656	655	652	651	650	7,899
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		643	642	642	642	640	639	636	635	634	630	628	627	7,638
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)		643	642	642	642	640	639	636	635	634	630	628	627	7,638

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	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)	(1,447,293)	(1,517,803)	(1,588,313)	(1,658,823)	(1,729,333)	(1,799,843)	(1,870,353)	(1,940,863)	(2,011,373)	(2,081,883)	(2,152,393)	(2,222,903)	(2,293,413)	
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)	28,392,385	28,321,875	28,251,365	28,180,855	28,110,345	28,039,835	27,969,325	27,898,815	27,828,305	27,757,795	27,687,285	27,616,775	27,546,265	
6	Average Net Investment		28,357,130	28,286,620	28,216,110	28,145,600	28,075,090	28,004,580	27,934,070	27,863,560	27,793,050	27,722,540	27,652,030	27,581,520	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		208,340	207,822	207,304	206,786	206,268	205,750	205,232	204,714	204,196	203,678	203,159	202,641	2,465,890
	b Debt Component (Line 6 x Debt Component x 1/12)		59,181	59,034	58,887	58,740	58,593	58,446	58,298	58,151	58,004	57,857	57,710	57,563	700,464
8	Investment Expenses														
	a Depreciation (E)		70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	846,120
	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)		338,031	337,366	336,701	336,036	335,371	334,706	334,040	333,375	332,710	332,045	331,379	330,714	4,012,474
	a Recoverable Costs Allocated to Energy		338,031	337,366	336,701	336,036	335,371	334,706	334,040	333,375	332,710	332,045	331,379	330,714	4,012,474
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		325,986	325,495	325,568	325,648	324,898	324,459	323,516	322,629	322,031	320,830	319,628	319,121	3,879,809
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)		325,986	325,495	325,568	325,648	324,898	324,459	323,516	322,629	322,031	320,830	319,628	319,121	3,879,809

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $13,997,697; Smith $15,715,200; Scholz $126,781. Ending Balances: Crist, $13,997,697; Smith $15,715,200; 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 3.2%; Smith 2.5%; Scholz 4.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	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)	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		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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 3.2% annually; Scholz 4.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.'s 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		0	0	0	0	0	0	0	0	0	0	0	7,801,485	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	7,801,485	
	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)	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	7,895,220	
3	Less: Accumulated Depreciation (C)	(6,148)	(6,398)	(6,648)	(6,898)	(7,148)	(7,398)	(7,648)	(7,898)	(8,148)	(8,398)	(8,648)	(8,898)	(19,551)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	87,587	87,337	87,087	86,837	86,587	86,337	86,087	85,837	85,587	85,337	85,087	84,837	7,875,669	
6	Average Net Investment		87,462	87,212	86,962	86,712	86,462	86,212	85,962	85,712	85,462	85,212	84,962	3,980,253	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		643	641	639	637	635	633	632	630	628	626	624	29,243	36,211
	b Debt Component (Line 6 x Debt Component x 1/12)		183	182	181	181	180	180	179	179	178	178	177	8,307	10,285
8	Investment Expenses														
	a Depreciation (E)		250	250	250	250	250	250	250	250	250	250	250	10,653	13,403
	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)		1,076	1,073	1,070	1,068	1,065	1,063	1,061	1,059	1,056	1,054	1,051	48,203	59,899
	a Recoverable Costs Allocated to Energy		83	83	82	82	82	82	82	81	81	81	81	3,708	4,608
	b Recoverable Costs Allocated to Demand		993	990	988	986	983	981	979	978	975	973	970	44,495	55,291
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		80	80	79	79	79	79	79	78	78	78	78	3,578	4,445
13	Retail Demand-Related Recoverable Costs (I)		957	955	953	951	948	946	944	943	940	938	935	42,903	53,313
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,037	1,035	1,032	1,030	1,027	1,025	1,023	1,021	1,018	1,016	1,013	46,481	57,758

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) 3.2% 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
(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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		6,863	(6,609)	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		6,863	(6,609)	0	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)	5,969,022	5,975,885	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	
3	Less: Accumulated Depreciation (C)	(498,352)	(514,280)	(530,208)	(546,128)	(562,048)	(577,968)	(593,888)	(609,808)	(625,728)	(641,648)	(657,568)	(673,488)	(689,408)	
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)	5,470,670	5,461,605	5,439,067	5,423,147	5,407,227	5,391,307	5,375,387	5,359,467	5,343,547	5,327,627	5,311,707	5,295,787	5,279,867	
6	Average Net Investment		5,466,137	5,450,336	5,431,107	5,415,187	5,399,267	5,383,347	5,367,427	5,351,507	5,335,587	5,319,667	5,303,747	5,287,827	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,160	40,044	39,902	39,785	39,668	39,551	39,434	39,318	39,201	39,084	38,967	38,850	473,964
	b Debt Component (Line 6 x Debt Component x 1/12)		11,408	11,375	11,335	11,301	11,268	11,235	11,202	11,169	11,135	11,102	11,069	11,036	134,635
8	Investment Expenses														
	a Depreciation (E)		15,928	15,928	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	191,056
	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)		67,496	67,347	67,157	67,006	66,856	66,706	66,556	66,407	66,256	66,106	65,956	65,806	799,655
	a Recoverable Costs Allocated to Energy		5,192	5,181	5,166	5,154	5,143	5,131	5,120	5,108	5,097	5,085	5,074	5,062	61,513
	b Recoverable Costs Allocated to Demand		62,304	62,166	61,991	61,852	61,713	61,575	61,436	61,299	61,159	61,021	60,882	60,744	738,142
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		5,007	4,999	4,995	4,995	4,982	4,974	4,959	4,943	4,933	4,913	4,894	4,885	59,479
13	Retail Demand-Related Recoverable Costs (I)		60,075	59,941	59,773	59,639	59,505	59,372	59,238	59,105	58,970	58,837	58,703	58,570	711,728
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		65,082	64,940	64,768	64,634	64,487	64,346	64,197	64,048	63,903	63,750	63,597	63,455	771,207

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) 3.2% 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 Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1222, 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		(200,921)	304,752	746,338	6,277,341	651,419	4,143,400	506,611	284,708	181,552	180,786	874,325	531,810,585	
	b Clearings to Plant		(323,013)	509,938	411,583	6,151,203	3,391,482	4,580,167	496,075	274,881	175,599	175,599	865,778	530,616,435	
	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)	60,689,270	60,366,257	60,876,195	61,287,778	67,438,981	70,830,463	75,410,629	75,906,704	76,181,585	76,357,184	76,532,783	77,398,561	608,014,996	
3	Less: Accumulated Depreciation (C)	(1,870,105)	(2,026,578)	(2,183,302)	(2,341,116)	(2,507,769)	(2,686,364)	(2,872,353)	(3,062,736)	(3,254,107)	(3,446,078)	(3,638,517)	(3,832,345)	(4,734,904)	
4	CWIP - Non Interest Bearing	4,529,518	4,651,611	4,446,425	4,781,180	4,907,319	2,167,256	1,730,489	1,741,025	1,750,852	1,756,805	1,761,992	1,770,539	2,964,689	
5	Net Investment (Lines 2 + 3 + 4)	63,348,683	62,991,289	63,139,318	63,727,842	69,838,530	70,311,355	74,268,766	74,584,994	74,678,331	74,667,912	74,656,259	75,336,756	606,244,781	
6	Average Net Investment		63,169,986	63,065,304	63,433,580	66,783,186	70,074,942	72,290,060	74,426,880	74,631,662	74,673,121	74,662,085	74,996,507	340,790,769	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		464,110	463,341	466,047	490,656	514,841	531,115	546,814	548,319	548,623	548,542	550,999	2,503,790	8,177,197
	b Debt Component (Line 6 x Debt Component x 1/12)		131,836	131,617	132,386	139,377	146,246	150,869	155,329	155,756	155,843	155,820	156,518	711,230	2,322,827
8	Investment Expenses														
	a Depreciation (E)		156,015	156,266	157,356	166,195	178,137	185,531	189,925	190,913	191,513	191,981	193,370	902,101	2,859,303
	b Amortization (F)		458	458	458	458	458	458	458	458	458	458	458	458	5,496
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	109,968
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		761,583	760,846	765,411	805,850	848,846	877,137	901,690	904,610	905,601	905,965	910,509	4,126,743	13,474,791
	a Recoverable Costs Allocated to Energy		761,583	760,846	765,411	805,850	848,846	877,137	901,690	904,610	905,601	905,965	910,509	4,126,743	13,474,791
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		734,446	734,074	740,103	780,939	822,339	850,284	873,283	875,451	876,533	875,365	878,222	3,982,082	13,023,121
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)		734,446	734,074	740,103	780,939	822,339	850,284	873,283	875,451	876,533	875,365	878,222	3,982,082	13,023,121

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $49,169,696; Smith $7,698,377; Daniel $3,264,866, Scholz $556,331. Ending Balances: Crist $592,369,378; Smith $11,389,634; Daniel $3,592,561, Scholz $663,423.
(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: 3.2%, Plant Smith Steam 2.5%, Smith CT 0.4%, Daniel 3.1%, Scholz 4.2%. Portion of PE 1222 is transmission 0.1833%, 0.1917%, 0.3417%, 0.2167%.
(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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	
3	Less: Accumulated Depreciation (C)	(4,731)	(5,125)	(5,519)	(5,913)	(6,307)	(6,701)	(7,095)	(7,489)	(7,883)	(8,277)	(8,671)	(9,065)	(9,459)	
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)	18,923	18,529	18,135	17,741	17,347	16,953	16,559	16,165	15,771	15,377	14,983	14,589	14,195	
6	Average Net Investment		18,726	18,332	17,938	17,544	17,150	16,756	16,362	15,968	15,574	15,180	14,786	14,392	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		138	135	132	129	126	123	120	117	114	112	109	106	1,461
	b Debt Component (Line 6 x Debt Component x 1/12)		39	38	37	37	36	35	34	33	33	32	31	30	415
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		394	394	394	394	394	394	394	394	394	394	394	394	4,728
	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)		571	567	563	560	556	552	548	544	541	538	534	530	6,604
	a Recoverable Costs Allocated to Energy		44	44	43	43	43	42	42	42	42	41	41	41	508
	b Recoverable Costs Allocated to Demand		527	523	520	517	513	510	506	502	499	497	493	489	6,096
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		42	42	42	42	42	41	41	41	41	40	40	40	494
13	Retail Demand-Related Recoverable Costs (I)		508	504	501	498	495	492	488	484	481	479	475	472	5,877
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		550	546	543	540	537	533	529	525	522	519	515	512	6,371

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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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 SO2 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		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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. Based on ROE of 12% and weighted income tax rate of 38.575%
(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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	7,016,000	5,002,500	587,500	1,623,500	4,025,000	2,037,500	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	7,016,000	11,444,399	10,996,347	11,249,597	13,938,655	13,808,885	11,441,268	9,248,326	7,380,055	5,416,850	3,315,044	
	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	7,016,000	11,444,399	10,996,347	11,249,597	13,938,655	13,808,885	11,441,268	9,248,326	7,380,055	5,416,850	3,315,044	
4	Average Net Working Capital Balance		0	3,508,000	9,230,199	11,220,373	11,122,972	12,594,126	13,873,770	12,625,077	10,344,797	8,314,191	6,398,452	4,365,947	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	25,773	67,814	82,436	81,720	92,529	101,931	92,756	76,003	61,084	47,009	32,077	761,132
	b Debt Component (Line 4 x Debt Component x 1/12)		0	7,321	19,263	23,417	23,214	26,284	28,955	26,349	21,590	17,352	13,354	9,112	216,211
6	Total Return Component (D)		0	33,094	87,077	105,853	104,934	118,813	130,886	119,105	97,593	78,436	60,363	41,189	977,343
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 SO2 Allowance Expense		0	0	574,101	1,035,552	1,370,250	1,335,942	2,167,270	2,367,617	2,192,942	1,868,272	1,963,205	2,101,806	16,976,956
8	Net Expenses (E)		0	0	574,101	1,035,552	1,370,250	1,335,942	2,167,270	2,367,617	2,192,942	1,868,272	1,963,205	2,101,806	16,976,956
9	Total System Recoverable Expenses (Lines 6 + 8)		0	33,094	661,178	1,141,405	1,475,184	1,454,755	2,298,156	2,486,722	2,290,535	1,946,708	2,023,568	2,142,995	17,954,299
	a Recoverable Costs Allocated to Energy		0	33,094	661,178	1,141,405	1,475,184	1,454,755	2,298,156	2,486,722	2,290,535	1,946,708	2,023,568	2,142,995	17,954,299
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		0	31,930	639,317	1,106,122	1,429,118	1,410,218	2,225,755	2,406,564	2,217,014	1,880,956	1,951,811	2,067,873	17,366,678
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	31,930	639,317	1,106,122	1,429,118	1,410,218	2,225,755	2,406,564	2,217,014	1,880,956	1,951,811	2,067,873	17,366,678

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	1,022,000	10,000	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	1,022,000	1,032,000	849,952	688,713	476,395	264,077	67,424	67,424	67,424	67,424	
	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	1,022,000	1,032,000	849,952	688,713	476,395	264,077	67,424	67,424	67,424	67,424	
4	Average Net Working Capital Balance		0	0	511,000	1,027,000	940,976	769,333	582,554	370,236	165,751	67,424	67,424	67,424	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	3,754	7,545	6,913	5,652	4,280	2,720	1,218	495	495	495	33,567
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	1,066	2,143	1,964	1,606	1,216	773	346	141	141	141	9,537
6	Total Return Component (D)		0	0	4,820	9,688	8,877	7,258	5,496	3,493	1,564	636	636	636	43,104
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 SO2 Allowance Expense		0	0	0	0	182,048	161,239	212,318	212,318	196,654	0	0	0	964,576
8	Net Expenses (E)		0	0	0	0	182,048	161,239	212,318	212,318	196,654	0	0	0	964,576
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	4,820	9,688	190,925	168,497	217,814	215,811	198,218	636	636	636	1,007,680
	a Recoverable Costs Allocated to Energy		0	0	4,820	9,688	190,925	168,497	217,814	215,811	198,218	636	636	636	1,007,680
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		0	0	4,661	9,389	184,963	163,339	210,952	208,854	191,855	615	613	614	975,855
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	4,661	9,389	184,963	163,339	210,952	208,854	191,855	615	613	614	975,855

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(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 Current Period Estimated True-Up Amount
January 2009 - December 2009

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	8,832,000	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	48,693	0	(5,825)	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	7,911,392	7,719,950	7,608,588	7,437,171	7,245,362	6,907,350	15,444,589	14,588,006	13,724,407	12,909,917	12,434,666	11,919,698	11,211,121	
	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	(1,054,181)	(1,048,089)	(1,041,997)	(1,035,905)	(1,073,567)	(1,062,534)	(1,046,509)	(1,036,309)	(1,026,109)	(1,015,909)	(1,005,709)	(995,509)	(985,309)	
3	Total Working Capital Balance	6,857,211	6,671,861	6,566,591	6,401,265	6,171,795	5,844,815	14,398,080	13,551,696	12,698,297	11,894,008	11,428,957	10,924,188	10,225,812	
4	Average Net Working Capital Balance		6,764,536	6,619,226	6,483,928	6,286,530	6,008,305	10,121,447	13,974,888	13,124,997	12,296,152	11,661,482	11,176,572	10,575,000	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		49,699	48,631	47,637	46,187	44,143	74,362	102,674	96,429	90,340	85,677	82,114	77,695	845,588
	b Debt Component (Line 4 x Debt Component x 1/12)		14,118	13,814	13,532	13,120	12,539	21,123	29,166	27,392	25,662	24,338	23,326	22,070	240,200
6	Total Return Component (D)		63,817	62,445	61,169	59,307	56,682	95,485	131,840	123,821	116,002	110,015	105,440	99,765	1,085,788
7	Expenses														
	a Gains		(6,092)	(6,092)	(6,092)	(11,032)	(11,032)	(10,200)	(10,200)	(10,200)	(10,200)	(10,200)	(10,200)	(10,200)	(111,739)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		191,441	111,362	171,418	191,809	338,012	294,760	856,583	863,599	814,490	475,251	514,968	708,577	5,532,271
8	Net Expenses (E)		185,350	105,270	165,326	180,777	326,980	284,560	846,383	853,399	804,290	465,051	504,768	698,377	5,420,531
9	Total System Recoverable Expenses (Lines 6 + 8)		249,167	167,715	226,495	240,084	383,662	380,045	978,223	977,220	920,292	575,066	610,208	798,142	6,506,319
	a Recoverable Costs Allocated to Energy		249,167	167,715	226,495	240,084	383,662	380,045	978,223	977,220	920,292	575,066	610,208	798,142	6,506,319
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		240,288	161,814	219,006	232,662	371,681	368,410	947,406	945,720	890,752	555,643	588,570	770,163	6,292,115
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)		240,288	161,814	219,006	232,662	371,681	368,410	947,406	945,720	890,752	555,643	588,570	770,163	6,292,115

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(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

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 090007-EI

BEFORE me, the undersigned authority, personally appeared Richard W. Dodd, who being first duly sworn, deposes and says that he is the Supervisor of Rates and Regulatory Matters at Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Richard W. Dodd
Supervisor of Rates and Regulatory Matters

Sworn to and subscribed before me
this 31st day of July, 2009.

Linda C. Webb
Notary Public, State of Florida at Large

(SEAL)

LINDA C. WEBB
Notary Public-State of Florida
Comm. Exp. May 31, 2010
Comm. No. DD 541216

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2010 - December 2010

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)	36,127,453	2,705,858	38,833,311
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	112,204,438	4,901,216	117,105,654
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	148,331,891	7,607,074	155,938,965
2	True-Up for Estimated Over/(Under) Recovery for the period January 2009 - December 2009 (Schedule 1E, Line 3)	374,499	30,628	405,127
3	Final True-Up for the period January 2008 - December 2008 (Schedule 1A, Line 3)	1,227,936	153,475	1,381,411
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2010 - December 2010 (Line 1c - Line 2 - Line 3)	146,729,456	7,422,971	154,152,427
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	146,835,101	7,428,316	154,263,417

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.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 34
COMPANY Gulf Power Company (Direct)
WITNESS R. W. Dodd (RWD-3)
DATE 11/02/09

Gulf Power Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2010 - December 2010

Schedule 2P

O & M Activities
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	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	0	0	0	0	0	0	0	0	0	0	0	0
	.2 Air Emission Fees	0	786,000	6,000	0	0	0	0	0	0	0	124,374	0	916,374	0	916,374
	.3 Title V	8,885	8,885	9,820	9,458	9,158	10,858	13,719	12,458	9,908	9,658	9,158	14,469	126,436	0	126,436
	.4 Asbestos Fees	0	0	500	700	300	0	0	300	400	200	0	200	2,600	2,600	0
	.5 Emission Monitoring	58,133	38,133	43,932	39,030	63,030	43,330	48,800	49,030	45,330	39,030	39,030	53,108	559,914	0	559,914
	.6 General Water Quality	23,540	23,740	45,760	36,860	24,534	49,034	34,429	34,034	46,034	30,784	30,534	62,425	441,707	441,707	0
	.7 Groundwater Contamination Investigation	71,928	72,660	76,454	82,841	87,841	414,641	111,957	87,841	408,641	83,841	63,841	67,961	1,630,452	1,630,452	0
	.8 State NPDES Administration	0	7,500	0	0	0	0	0	0	0	0	0	34,500	42,000	42,000	0
	.9 Lead and Copper Rule	5,250	0	0	5,250	0	0	5,250	0	0	5,250	0	0	21,000	21,000	0
	.10 Env Auditing/Assessment	500	0	500	0	5,000	3,000	0	2,000	0	500	500	0	12,000	12,000	0
	.11 General Solid & Hazardous Waste	32,126	33,183	35,974	43,854	45,283	44,846	53,590	53,949	56,513	50,681	44,682	63,453	558,133	558,133	0
	.12 Above Ground Storage Tanks	978	978	10,494	994	1,494	10,494	4,240	4,494	41,494	5,494	4,994	12,240	98,387	98,387	0
	.13 Low Nox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.14 Ash Pond Diversion Curtains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.15 Mercury Emissions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.16 Sodium Injection	24,499	15,999	24,499	15,999	24,499	15,999	24,499	15,999	24,499	15,999	24,499	16,000	242,989	0	242,989
	.17 Gulf Coast Ozone Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.18 SPCC Substation Project	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 FDEP NOX Reduction Agreement	218,089	211,596	224,800	232,122	225,629	225,629	279,030	227,859	219,225	159,955	186,757	236,811	2,647,500	0	2,647,500
	.20 CAIR/CAMR/CAVR Compliance Program	1,691,638	1,739,638	1,692,972	1,692,973	1,708,366	1,708,366	1,753,617	1,694,519	1,695,791	1,695,792	1,796,992	1,858,941	20,729,607	0	20,729,607
	.21 MACT ICR	13,525	13,525	27,050	64,920	81,150	108,200	129,840	75,740	27,050	0	0	0	541,000	0	541,000
	.22 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.23 Annual NOx Allowances	2,200,537	157,270	201,251	299,594	341,674	549,130	824,904	851,254	767,080	782,451	707,061	731,215	8,413,422	0	8,413,422
	.24 Seasonal NOx Allowances	0	0	0	0	13,757	14,944	82,480	167,328	150,913	0	0	0	429,422	0	429,422
	.25 SO_2 Allowances	334,032	215,996	165,504	169,006	194,491	229,254	250,008	260,078	237,223	243,440	228,991	235,559	2,763,581	0	2,763,581
2	Total of O & M Activities	4,683,661	3,325,103	2,565,509	2,693,601	2,826,206	3,427,725	3,616,363	3,536,883	3,730,101	3,123,076	3,261,413	3,386,883	40,176,524	2,806,278	37,370,246
3	Recoverable Costs Allocated to Energy	4,549,338	3,187,042	2,395,827	2,523,102	2,661,754	2,905,710	3,406,897	3,354,266	3,177,019	2,946,326	3,116,862	3,146,103	37,370,246		
4	Recoverable Costs Allocated to Demand	134,322	138,061	169,682	170,499	164,452	522,015	209,467	182,618	553,082	176,750	144,551	240,780	2,806,278		
5	Retail Energy Jurisdictional Factor	0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (A)	4,391,792	3,079,160	2,314,230	2,442,573	2,576,902	2,812,956	3,298,502	3,246,005	3,074,436	2,846,770	3,008,206	3,035,921	36,127,453		
8	Jurisdictional Demand Recoverable Costs (B)	129,516	133,121	163,610	164,398	158,567	503,335	201,971	176,083	533,290	170,425	139,378	232,164	2,705,858		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	4,521,308	3,212,281	2,477,840	2,606,971	2,735,469	3,316,291	3,500,473	3,422,088	3,607,726	3,017,195	3,147,584	3,268,085	38,833,311		

Notes:
(A) Line 3 x Line 5 x 1.0007 line loss multiplier
(B) Line 4 x Line 6

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Schedule 3P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	End of Period Total	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,157	3,133	39,220	0	39,220
	.2 Crist 5, 6 & 7 Precipitator Projects	154,245	155,188	155,657	156,129	156,362	156,363	156,360	156,358	156,160	156,594	157,063	157,770	1,874,449	0	1,874,449
	.3 Crist 7 Flue Gas Conditioning	14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,009	14,006	14,005	14,003	14,001	168,138	0	168,138
	.4 Low NOx Burners, Crist 6 & 7	166,788	166,560	166,332	166,101	165,873	165,643	165,416	165,188	164,956	164,729	164,499	164,272	1,986,357	0	1,986,357
	.5 CEMs- Plants Crist, Scholz, Smith, and Daniel	81,710	79,264	76,831	76,730	76,628	76,536	76,435	76,338	76,235	76,137	76,038	75,938	924,820	0	924,820
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	8,380	8,363	8,346	8,329	8,311	8,294	8,277	8,258	8,242	8,224	8,209	8,190	99,423	91,774	7,649
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,215	2,209	2,204	2,198	2,193	2,187	2,181	2,177	2,170	2,166	2,160	2,154	26,214	24,198	2,016
	.8 Crist Cooling Tower Cell	4,920	4,918	4,917	4,916	4,914	4,912	4,911	4,909	4,908	4,907	4,905	4,903	58,940	54,407	4,533
	.9 Crist 1-5 Dechlorination	2,223	2,215	2,207	2,199	2,192	2,184	2,176	2,169	2,161	2,153	2,146	2,138	26,163	24,151	2,012
	.10 Crist Diesel Fuel Oil Remediation	561	560	558	556	554	553	551	549	547	546	544	542	6,621	6,111	510
	.11 Crist Bulk Tanker Unload Sec Contain Struc	740	737	735	732	729	727	724	722	719	717	714	711	8,707	8,036	671
	.12 Crist FWW Sampling System	431	430	428	426	425	424	422	421	419	417	416	415	5,074	4,684	390
	.13 Sodium Injection System	3,990	3,979	3,971	3,961	3,951	3,944	3,933	3,926	3,915	3,906	3,897	3,887	47,260	0	47,260
	.14 Smith Stormwater Collection System	20,579	20,525	20,470	20,416	20,361	20,306	20,252	20,197	20,143	20,088	20,033	19,978	243,348	224,629	18,719
	.15 Smith Waste Water Treatment Facility	2,961	2,957	2,954	2,951	2,947	2,944	2,938	2,936	2,933	2,928	2,926	2,922	35,297	32,581	2,716
	.16 Daniel Ash Management Project	177,286	176,795	176,303	175,812	175,329	174,827	174,335	173,843	173,352	172,861	172,368	171,876	2,094,978	1,933,825	161,153
	.17 Smith Water Conservation	1,927	3,101	4,274	5,451	6,629	7,803	8,980	10,155	11,332	12,508	13,684	14,865	100,709	92,964	7,745
	.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	1,462,603	1,458,926	1,455,249	1,451,573	1,447,897	1,444,219	1,440,545	1,436,870	1,433,193	1,429,517	1,425,840	1,422,164	17,308,594	0	17,308,594
	.20 SPCC Compliance	10,561	10,538	10,514	10,491	10,466	10,443	10,420	10,396	10,372	10,348	10,325	10,302	125,176	115,547	9,629
	.21 Crist Common FTIR Monitor	648	646	644	643	642	640	638	637	635	634	632	630	7,669	0	7,669
	.22 Precipitator Upgrades for CAM Compliance	330,049	329,384	328,719	328,052	327,388	326,723	326,069	325,392	324,726	324,063	323,397	322,732	3,916,685	0	3,916,685
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	99,088	105,918	110,514	113,654	116,325	158,248	198,924	198,508	198,089	197,672	197,254	196,836	1,891,027	1,745,562	145,465
	.25 Plant NPDES Permit Compliance Projects	65,654	65,506	65,355	65,205	65,054	64,903	64,754	64,603	64,513	64,680	64,449	64,481	778,958	719,039	59,919
	.26 CAIR/CAMR/CAVR Compliance Program	7,356,729	7,366,291	7,368,291	7,364,268	7,353,339	7,346,054	7,337,668	7,322,976	7,307,493	7,292,009	7,276,525	7,261,513	87,953,156	0	87,953,156
	.27 General Water Quality	526	522	519	515	511	507	503	500	497	493	489	485	6,067	5,601	466
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual Nox Allowances	23,229	18,393	27,374	31,733	36,208	49,719	53,449	45,543	37,909	30,600	23,574	16,790	394,521	0	394,521
	.30 Seasonal Nox Allowances	636	636	636	636	531	1,291	2,539	2,233	733	0	0	0	9,869	0	9,869
	.31 SO2 Allowances	94,895	92,300	90,501	88,923	87,208	85,209	82,949	80,543	78,197	75,929	73,701	71,549	1,401,864	0	1,401,864
2	Total Investment Projects - Recoverable Costs	10,060,999	10,094,260	10,101,876	10,099,944	10,090,317	10,132,896	10,163,606	10,133,569	10,101,939	10,071,813	10,042,948	10,015,437	121,139,304	5,083,109	116,056,195
3	Recoverable Costs Allocated to Energy	9,723,565	9,720,142	9,723,141	9,717,930	9,705,460	9,708,961	9,701,745	9,671,714	9,649,031	9,609,805	9,580,837	9,552,864	116,056,195		
4	Recoverable Costs Allocated to Demand	367,434	374,118	378,735	382,014	384,857	423,935	461,861	461,855	461,908	462,008	462,111	462,573	5,083,109		
5	Retail Energy Jurisdictional Factor	0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644042	0.9643030			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (B)	9,386,832	9,391,116	9,391,988	9,407,767	9,396,069	9,399,039	9,393,071	9,359,555	9,338,762	9,283,092	9,246,843	9,218,304	112,204,438		
8	Jurisdictional Demand Recoverable Costs (C)	354,286	360,331	365,182	368,344	371,085	408,765	445,334	445,328	445,379	445,476	445,575	445,731	4,901,216		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	9,741,118	9,751,447	9,757,170	9,776,111	9,767,154	9,807,804	9,838,405	9,804,883	9,774,141	9,730,568	9,692,418	9,664,035	117,105,654		

Notes:

(A) Each project's Total System Recoverable Expenses as shown on Schedule 4P, Line 9. Allowances recoverable costs shown on Schedule 4P, Line 6
(B) Line 3 x Line 5 x 1.0007 line loss multiplier
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010

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	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	End of Period Amount
1	Investments (A)														
	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)	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	
3	Less: Accumulated Depreciation (C)	(136,158)	(138,781)	(141,404)	(144,027)	(146,650)	(149,273)	(151,896)	(154,519)	(157,142)	(159,765)	(162,388)	(165,011)	(167,634)	
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)	84,136	81,513	78,890	76,267	73,644	71,021	68,398	65,775	63,152	60,529	57,906	55,283	52,660	
6	Average Net Investment		82,825	80,202	77,579	74,956	72,333	69,710	67,087	64,464	61,841	59,218	56,595	53,972	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		609	589	570	551	531	512	493	474	454	435	416	397	6,031
	b Debt Component (Line 6 x Debt Component x 1/12)		173	167	162	156	151	145	140	135	129	124	118	113	1,713
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	31,476
	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)		3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,157	3,133	39,220
	a Recoverable Costs Allocated to Energy		3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,157	3,133	39,220
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,287	3,265	3,241	3,224	3,200	3,175	3,152	3,128	3,102	3,074	3,047	3,023	37,918
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		3,287	3,265	3,241	3,224	3,200	3,175	3,152	3,128	3,102	3,074	3,047	3,023	37,918

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 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
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010

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	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		200,000	100,000	100,000	100,000	50,000	50,000	50,000	50,000	50,000	100,000	100,000	150,000	
	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 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)	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	
3	Less: Accumulated Depreciation (C)	(3,570,817)	(3,620,949)	(3,671,081)	(3,721,213)	(3,771,345)	(3,821,477)	(3,871,609)	(3,921,741)	(3,971,873)	(4,022,005)	(4,072,137)	(4,122,269)	(4,172,401)	
4	CWIP - Non Interest Bearing	0	200,000	300,000	400,000	500,000	550,000	600,000	650,000	700,000	750,000	850,000	950,000	1,100,000	
5	Net Investment (Lines 2 + 3 + 4)	10,961,062	11,110,930	11,160,798	11,210,666	11,260,534	11,260,402	11,260,270	11,260,138	11,260,006	11,259,874	11,309,742	11,359,610	11,459,478	
6	Average Net Investment		11,035,996	11,135,864	11,185,732	11,235,600	11,260,468	11,260,336	11,260,204	11,260,072	11,259,940	11,284,808	11,334,676	11,409,544	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		81,081	81,815	82,181	82,548	82,729	82,730	82,728	82,727	82,728	82,910	83,276	83,826	991,279
	b Debt Component (Line 6 x Debt Component x 1/12)		23,032	23,241	23,344	23,449	23,501	23,501	23,500	23,499	23,500	23,552	23,655	23,812	281,586
8	Investment Expenses														
	a Depreciation (E)		38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	465,084
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	136,500
	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)		154,245	155,188	155,657	156,129	156,362	156,363	156,360	156,358	156,360	156,594	157,063	157,770	1,874,449
	a Recoverable Costs Allocated to Energy		154,245	155,188	155,657	156,129	156,362	156,363	156,360	156,358	156,360	156,594	157,063	157,770	1,874,449
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		148,904	149,934	150,355	151,147	151,378	151,373	151,386	151,311	151,311	151,303	151,588	152,245	1,812,235
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		148,904	149,934	150,355	151,147	151,378	151,373	151,386	151,311	151,311	151,303	151,588	152,245	1,812,235

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010

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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	1,464,825	1,464,621	1,464,417	1,464,213	1,464,009	1,463,805	1,463,601	1,463,397	1,463,193	1,462,989	1,462,785	1,462,581	1,462,377	
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)	1,464,825	1,464,621	1,464,417	1,464,213	1,464,009	1,463,805	1,463,601	1,463,397	1,463,193	1,462,989	1,462,785	1,462,581	1,462,377	
6	Average Net Investment		1,464,723	1,464,519	1,464,315	1,464,111	1,463,907	1,463,703	1,463,499	1,463,295	1,463,091	1,462,887	1,462,683	1,462,479	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,761	10,760	10,758	10,757	10,755	10,754	10,752	10,751	10,749	10,748	10,746	10,745	129,036
	b Debt Component (Line 6 x Debt Component x 1/12)		3,057	3,056	3,056	3,056	3,055	3,055	3,054	3,054	3,053	3,053	3,053	3,052	36,654
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		204	204	204	204	204	204	204	204	204	204	204	204	2,448
	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)		14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,009	14,006	14,005	14,003	14,001	168,138
	a Recoverable Costs Allocated to Energy		14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,009	14,006	14,005	14,003	14,001	168,138
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,536	13,545	13,541	13,570	13,567	13,566	13,564	13,557	13,554	13,532	13,515	13,511	162,558
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		13,536	13,545	13,541	13,570	13,567	13,566	13,564	13,557	13,554	13,532	13,515	13,511	162,558

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010
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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	
3	Less: Accumulated Depreciation (C)	6,021,777	5,997,513	5,973,249	5,948,985	5,924,721	5,900,457	5,876,193	5,851,929	5,827,665	5,803,401	5,779,137	5,754,873	5,730,609	
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)	15,119,700	15,095,436	15,071,172	15,046,908	15,022,644	14,998,380	14,974,116	14,949,852	14,925,588	14,901,324	14,877,060	14,852,796	14,828,532	
6	Average Net Investment		15,107,568	15,083,304	15,059,040	15,034,776	15,010,512	14,986,248	14,961,984	14,937,720	14,913,456	14,889,192	14,864,928	14,840,664	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		110,995	110,817	110,639	110,460	110,282	110,104	109,926	109,748	109,568	109,391	109,212	109,035	1,320,177
	b Debt Component (Line 6 x Debt Component x 1/12)		31,529	31,479	31,429	31,377	31,327	31,275	31,226	31,176	31,124	31,074	31,023	30,973	375,012
8	Investment Expenses														
	a Depreciation (E)		24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	291,168
	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)		166,788	166,560	166,332	166,101	165,873	165,643	165,416	165,188	164,956	164,729	164,499	164,272	1,986,357
	a Recoverable Costs Allocated to Energy		166,788	166,560	166,332	166,101	165,873	165,643	165,416	165,188	164,956	164,729	164,499	164,272	1,986,357
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		161,012	160,922	160,667	160,800	160,585	160,355	160,153	159,857	159,629	159,163	158,765	158,519	1,920,427
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		161,012	160,922	160,667	160,800	160,585	160,355	160,153	159,857	159,629	159,163	158,765	158,519	1,920,427

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CEMs- Plants Crist, Scholz, Smith, and Daniel
P.E.s 1001, 1154, 1164, 1217, 1240, 1245, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 1558, 1570, 1658, 1829 & 1830
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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	1,738,270	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)	5,760,066	5,760,066	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	
3	Less: Accumulated Depreciation (C)	1,162,923	1,147,762	2,873,187	2,862,661	2,852,135	2,841,609	2,831,083	2,820,557	2,810,031	2,799,505	2,788,979	2,778,453	2,767,927	
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)	6,922,989	6,907,828	6,894,983	6,884,457	6,873,931	6,863,405	6,852,879	6,842,353	6,831,827	6,821,301	6,810,775	6,800,249	6,789,723	
6	Average Net Investment		6,915,409	6,901,406	6,889,720	6,879,194	6,868,668	6,858,142	6,847,616	6,837,090	6,826,564	6,816,038	6,805,512	6,794,986	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		50,808	50,706	50,617	50,540	50,461	50,387	50,308	50,234	50,154	50,076	50,000	49,922	604,213
	b Debt Component (Line 6 x Debt Component x 1/12)		14,432	14,404	14,379	14,355	14,332	14,314	14,292	14,269	14,246	14,226	14,203	14,181	171,633
8	Investment Expenses														
	a Depreciation (E)		15,029	12,713	10,394	10,394	10,394	10,394	10,394	10,394	10,394	10,394	10,394	10,394	131,682
	b Amortization (F)		132	132	132	132	132	132	132	132	132	132	132	132	1,584
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	15,708
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		81,710	79,264	76,831	76,730	76,628	76,536	76,435	76,338	76,235	76,137	76,038	75,938	924,820
	a Recoverable Costs Allocated to Energy		81,710	79,264	76,831	76,730	76,628	76,536	76,435	76,338	76,235	76,137	76,038	75,938	924,820
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		77,890	75,590	73,225	73,293	73,199	73,105	73,016	72,887	72,788	72,583	72,409	72,300	882,285
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		77,890	75,590	73,225	73,293	73,199	73,105	73,016	72,887	72,788	72,583	72,409	72,300	882,285

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project.
(B) Beginning Balances: Crist, $2,521,809; Scholz $916,802; Smith $1,740,179; Daniel $581,275. Ending Balances: Crist, $783,539; Scholz $916,802; Smith $1,740,179; Daniel $581,275.
(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: 3.2%; Smith 2.5%; Scholz 4.2%; Daniel 3.1% 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 Projected Period Amount
January 2010 - December 2010
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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	(223,370)	(225,206)	(227,042)	(228,878)	(230,714)	(232,550)	(234,386)	(236,222)	(238,058)	(239,894)	(241,730)	(243,566)	(245,402)	
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)	694,654	692,818	690,982	689,146	687,310	685,474	683,638	681,802	679,966	678,130	676,294	674,458	672,622	
6	Average Net Investment		693,736	691,900	690,064	688,228	686,392	684,556	682,720	680,884	679,048	677,212	675,376	673,540	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,097	5,083	5,070	5,056	5,043	5,029	5,016	5,002	4,989	4,975	4,963	4,949	60,272
	b Debt Component (Line 6 x Debt Component x 1/12)		1,447	1,444	1,440	1,437	1,432	1,429	1,425	1,420	1,417	1,413	1,410	1,405	17,119
8	Investment Expenses														
	a Depreciation (E)		1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	22,032
	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)		8,380	8,363	8,346	8,329	8,311	8,294	8,277	8,258	8,242	8,224	8,209	8,190	99,423
	a Recoverable Costs Allocated to Energy		644	643	642	641	640	637	637	636	634	633	632	630	7,649
	b Recoverable Costs Allocated to Demand		7,736	7,720	7,704	7,688	7,671	7,657	7,640	7,622	7,608	7,591	7,577	7,560	91,774
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674348	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		622	622	620	621	620	617	617	616	614	612	610	608	7,399
13	Retail Demand-Related Recoverable Costs (I)		7,459	7,443	7,429	7,413	7,396	7,383	7,367	7,350	7,336	7,319	7,305	7,289	88,489
14	Total Juris. Recoverable Costs (Lines 12 + 13)		8,081	8,065	8,049	8,034	8,016	8,000	7,984	7,966	7,950	7,931	7,915	7,897	95,888

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 2.4% annually. PEs 3400 and 3412 depreciable at 2.4% 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 Projected Period Amount
January 2010 - December 2010

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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	
3	Less: Accumulated Depreciation (C)	(70,824)	(71,418)	(72,012)	(72,606)	(73,200)	(73,794)	(74,388)	(74,982)	(75,576)	(76,170)	(76,764)	(77,358)	(77,952)	
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)	172,148	171,554	170,960	170,366	169,772	169,178	168,584	167,990	167,396	166,802	166,208	165,614	165,020	
6	Average Net Investment		171,851	171,257	170,663	170,069	169,475	168,881	168,287	167,693	167,099	166,505	165,911	165,317	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,262	1,258	1,254	1,249	1,245	1,240	1,236	1,233	1,228	1,224	1,219	1,215	14,863
	b Debt Component (Line 6 x Debt Component x 1/12)		359	357	356	355	354	353	351	350	348	348	347	345	4,223
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	594	594	594	594	594	594	594	594	7,128
	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)		2,215	2,209	2,204	2,198	2,193	2,187	2,181	2,177	2,170	2,166	2,160	2,154	26,214
	a Recoverable Costs Allocated to Energy		170	170	169	169	169	168	168	168	167	166	166	166	2,016
	b Recoverable Costs Allocated to Demand		2,045	2,039	2,035	2,029	2,024	2,019	2,013	2,009	2,003	2,000	1,994	1,988	24,198
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		164	164	163	164	164	163	163	163	162	160	160	160	1,950
13	Retail Demand-Related Recoverable Costs (I)		1,972	1,966	1,962	1,956	1,952	1,947	1,941	1,937	1,931	1,928	1,922	1,916	23,350
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,136	2,130	2,125	2,120	2,116	2,110	2,104	2,100	2,093	2,088	2,082	2,076	25,200

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,949 and 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 3.2%; Smith 2.5% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	504,424	504,262	504,100	503,938	503,776	503,614	503,452	503,290	503,128	502,966	502,804	502,642	502,480	
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)	504,424	504,262	504,100	503,938	503,776	503,614	503,452	503,290	503,128	502,966	502,804	502,642	502,480	
6	Average Net Investment		504,343	504,181	504,019	503,857	503,695	503,533	503,371	503,209	503,047	502,885	502,723	502,561	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,705	3,704	3,703	3,702	3,701	3,699	3,698	3,697	3,696	3,695	3,694	3,692	44,386
	b Debt Component (Line 6 x Debt Component x 1/12)		1,053	1,052	1,052	1,052	1,051	1,051	1,051	1,050	1,050	1,050	1,049	1,049	12,610
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		162	162	162	162	162	162	162	162	162	162	162	162	1,944
	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)		4,920	4,918	4,917	4,916	4,914	4,912	4,911	4,909	4,908	4,907	4,905	4,903	58,940
	a Recoverable Costs Allocated to Energy		378	378	378	378	378	378	378	378	378	377	377	377	4,533
	b Recoverable Costs Allocated to Demand		4,542	4,540	4,539	4,538	4,536	4,534	4,533	4,531	4,530	4,530	4,528	4,526	54,407
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		365	365	365	366	366	366	366	366	366	364	364	364	4,383
13	Retail Demand-Related Recoverable Costs (I)		4,379	4,378	4,377	4,376	4,374	4,372	4,371	4,369	4,368	4,368	4,366	4,364	52,462
14	Total Juris. Recoverable Costs (Lines 12 + 13)		4,744	4,743	4,742	4,742	4,740	4,738	4,737	4,735	4,734	4,732	4,730	4,728	56,845

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	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)	(155,627)	(156,441)	(157,255)	(158,069)	(158,883)	(159,697)	(160,511)	(161,325)	(162,139)	(162,953)	(163,767)	(164,581)	(165,395)	
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)	149,696	148,882	148,068	147,254	146,440	145,626	144,812	143,998	143,184	142,370	141,556	140,742	139,928	
6	Average Net Investment		149,289	148,475	147,661	146,847	146,033	145,219	144,405	143,591	142,777	141,963	141,149	140,335	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,097	1,091	1,085	1,079	1,073	1,067	1,061	1,055	1,049	1,043	1,037	1,031	12,768
	b Debt Component (Line 6 x Debt Component x 1/12)		312	310	308	306	305	303	301	300	298	296	295	293	3,627
8	Investment Expenses														
	a Depreciation (E)		814	814	814	814	814	814	814	814	814	814	814	814	9,768
	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)		2,223	2,215	2,207	2,199	2,192	2,184	2,176	2,169	2,161	2,153	2,146	2,138	26,163
	a Recoverable Costs Allocated to Energy		171	170	170	169	169	168	167	167	166	166	165	164	2,012
	b Recoverable Costs Allocated to Demand		2,052	2,045	2,037	2,030	2,023	2,016	2,009	2,002	1,995	1,987	1,981	1,974	24,151
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		165	164	164	164	164	163	162	162	161	160	159	158	1,946
13	Retail Demand-Related Recoverable Costs (I)		1,979	1,972	1,964	1,957	1,951	1,944	1,937	1,930	1,924	1,916	1,910	1,903	23,287
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,144	2,136	2,128	2,121	2,115	2,107	2,099	2,092	2,085	2,076	2,069	2,061	25,233

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 in 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) 3.2% 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 Projected Period Amount
January 2010 - December 2010

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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	(28,832)	(29,016)	(29,200)	(29,384)	(29,568)	(29,752)	(29,936)	(30,120)	(30,304)	(30,488)	(30,672)	(30,856)	(31,040)	
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)	40,091	39,907	39,723	39,539	39,355	39,171	38,987	38,803	38,619	38,435	38,251	38,067	37,883	
6	Average Net Investment		39,999	39,815	39,631	39,447	39,263	39,079	38,895	38,711	38,527	38,343	38,159	37,975	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		294	293	291	290	288	287	286	284	283	282	280	279	3,437
	b Debt Component (Line 6 x Debt Component x 1/12)		83	83	83	82	82	82	81	81	80	80	80	79	976
8	Investment Expenses														
	a Depreciation (E)		184	184	184	184	184	184	184	184	184	184	184	184	2,208
	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)		561	560	558	556	554	553	551	549	547	546	544	542	6,621
	a Recoverable Costs Allocated to Energy		43	43	43	43	43	43	42	42	42	42	42	42	510
	b Recoverable Costs Allocated to Demand		518	517	515	513	511	510	509	507	505	504	502	500	6,111
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		42	42	42	42	42	42	41	41	41	41	41	41	498
13	Retail Demand-Related Recoverable Costs (I)		499	498	497	495	493	492	491	489	487	486	484	482	5,893
14	Total Juris. Recoverable Costs (Lines 12 + 13)		541	540	539	537	535	534	532	530	528	527	525	523	6,391

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010

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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	(51,671)	(51,942)	(52,213)	(52,484)	(52,755)	(53,026)	(53,297)	(53,568)	(53,839)	(54,110)	(54,381)	(54,652)	(54,923)	
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)	49,824	49,553	49,282	49,011	48,740	48,469	48,198	47,927	47,656	47,385	47,114	46,843	46,572	
6	Average Net Investment		49,689	49,418	49,147	48,876	48,605	48,334	48,063	47,792	47,521	47,250	46,979	46,708	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		365	363	361	359	357	355	353	351	349	347	345	343	4,248
	b Debt Component (Line 6 x Debt Component x 1/12)		104	103	103	102	101	101	100	100	99	99	98	97	1,207
8	Investment Expenses														
	a Depreciation (E)		271	271	271	271	271	271	271	271	271	271	271	271	3,252
	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)		740	737	735	732	729	727	724	722	719	717	714	711	8,707
	a Recoverable Costs Allocated to Energy		57	57	57	56	56	56	56	56	55	55	55	55	671
	b Recoverable Costs Allocated to Demand		683	680	678	676	673	671	668	666	664	662	659	656	8,036
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		55	55	55	54	54	54	54	54	53	53	53	53	647
13	Retail Demand-Related Recoverable Costs (I)		659	656	654	652	649	647	644	642	640	638	635	633	7,749
14	Total Juris. Recoverable Costs (Lines 12 + 13)		714	711	709	706	703	701	698	696	693	691	688	686	8,396

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	(30,632)	(30,791)	(30,950)	(31,109)	(31,268)	(31,427)	(31,586)	(31,745)	(31,904)	(32,063)	(32,222)	(32,381)	(32,540)	
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)	28,911	28,752	28,593	28,434	28,275	28,116	27,957	27,798	27,639	27,480	27,321	27,162	27,003	
6	Average Net Investment		28,832	28,673	28,514	28,355	28,196	28,037	27,878	27,719	27,560	27,401	27,242	27,083	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		212	211	209	208	207	206	205	204	202	201	200	199	2,464
	b Debt Component (Line 6 x Debt Component x 1/12)		60	60	60	59	59	59	58	58	58	57	57	57	702
8	Investment Expenses														
	a Depreciation (E)		159	159	159	159	159	159	159	159	159	159	159	159	1,908
	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)		431	430	428	426	425	424	422	421	419	417	416	415	5,074
	a Recoverable Costs Allocated to Energy		33	33	33	33	33	33	32	32	32	32	32	32	390
	b Recoverable Costs Allocated to Demand		398	397	395	393	392	391	390	389	387	385	384	383	4,684
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		32	32	32	32	32	32	31	31	31	31	31	31	378
13	Retail Demand-Related Recoverable Costs (I)		384	383	381	379	378	377	376	375	373	371	370	369	4,516
14	Total Juris. Recoverable Costs (Lines 12 + 13)		416	415	413	411	410	409	407	406	404	402	401	400	4,894

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 & 1413
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	(71,763)	(72,744)	(73,725)	(74,706)	(75,687)	(76,668)	(77,649)	(78,630)	(79,611)	(80,592)	(81,573)	(82,554)	(83,535)	
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)	319,356	318,375	317,394	316,413	315,432	314,451	313,470	312,489	311,508	310,527	309,546	308,565	307,584	
6	Average Net Investment		318,866	317,885	316,904	315,923	314,942	313,961	312,980	311,999	311,018	310,037	309,056	308,075	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,343	2,335	2,329	2,321	2,313	2,307	2,299	2,293	2,285	2,278	2,271	2,263	27,637
	b Debt Component (Line 6 x Debt Component x 1/12)		666	663	661	659	657	656	653	652	649	647	645	643	7,851
8	Investment Expenses														
	a Depreciation (E)		981	981	981	981	981	981	981	981	981	981	981	981	11,772
	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)		3,990	3,979	3,971	3,961	3,951	3,944	3,933	3,926	3,915	3,906	3,897	3,887	47,260
	a Recoverable Costs Allocated to Energy		3,990	3,979	3,971	3,961	3,951	3,944	3,933	3,926	3,915	3,906	3,897	3,887	47,260
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,851	3,844	3,836	3,834	3,825	3,818	3,808	3,799	3,789	3,774	3,761	3,751	45,690
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		3,851	3,844	3,836	3,834	3,825	3,818	3,808	3,799	3,789	3,774	3,761	3,751	45,690

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 3.2% annually; Smith 2.5% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	(1,212,623)	(1,218,419)	(1,224,215)	(1,230,011)	(1,235,807)	(1,241,603)	(1,247,399)	(1,253,195)	(1,258,991)	(1,264,787)	(1,270,583)	(1,276,379)	(1,282,175)	
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)	1,569,977	1,564,181	1,558,385	1,552,589	1,546,793	1,540,997	1,535,201	1,529,405	1,523,609	1,517,813	1,512,017	1,506,221	1,500,425	
6	Average Net Investment		1,567,079	1,561,283	1,555,487	1,549,691	1,543,895	1,538,099	1,532,303	1,526,507	1,520,711	1,514,915	1,509,119	1,503,323	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		11,513	11,471	11,428	11,386	11,343	11,300	11,258	11,215	11,173	11,130	11,087	11,045	135,349
	b Debt Component (Line 6 x Debt Component x 1/12)		3,270	3,258	3,246	3,234	3,222	3,210	3,198	3,186	3,174	3,162	3,150	3,137	38,447
8	Investment Expenses														
	a Depreciation (E)		5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	69,552
	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)		20,579	20,525	20,470	20,416	20,361	20,306	20,252	20,197	20,143	20,088	20,033	19,978	243,348
	a Recoverable Costs Allocated to Energy		1,583	1,579	1,575	1,570	1,566	1,562	1,558	1,554	1,549	1,545	1,541	1,537	18,719
	b Recoverable Costs Allocated to Demand		18,996	18,946	18,895	18,846	18,795	18,744	18,694	18,643	18,594	18,543	18,492	18,441	224,629
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,528	1,526	1,521	1,520	1,516	1,512	1,508	1,504	1,499	1,493	1,487	1,483	18,097
13	Retail Demand-Related Recoverable Costs (I)		18,316	18,268	18,219	18,172	18,122	18,073	18,025	17,976	17,929	17,879	17,830	17,781	216,590
14	Total Juris. Recoverable Costs (Lines 12 + 13)		19,844	19,794	19,740	19,692	19,638	19,585	19,533	19,480	19,428	19,372	19,317	19,264	234,687

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) 2.5% 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 Projected Period Amount
January 2010 - December 2010

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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	95,527	95,154	94,781	94,408	94,035	93,662	93,289	92,916	92,543	92,170	91,797	91,424	91,051	
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)	274,489	274,116	273,743	273,370	272,997	272,624	272,251	271,878	271,505	271,132	270,759	270,386	270,013	
6	Average Net Investment		274,303	273,930	273,557	273,184	272,811	272,438	272,065	271,692	271,319	270,946	270,573	270,200	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,016	2,012	2,010	2,008	2,004	2,002	1,998	1,996	1,994	1,990	1,988	1,985	24,003
	b ~~Debt Component (Line 6 x Debt Component x 1/12)~~		~~572~~	~~572~~	~~571~~	~~570~~	~~570~~	~~569~~	~~567~~	~~567~~	~~566~~	~~565~~	~~565~~	~~564~~	6,818
8	Investment Expenses														
	a Depreciation (E)		373	373	373	373	373	373	373	373	373	373	373	373	4,476
	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)		2,961	2,957	2,954	2,951	2,947	2,944	2,938	2,936	2,933	2,928	2,926	2,922	35,297
	a Recoverable Costs Allocated to Energy		228	228	228	227	227	227	226	225	225	225	225	225	2,716
	b Recoverable Costs Allocated to Demand		2,733	2,729	2,726	2,724	2,720	2,717	2,712	2,711	2,708	2,703	2,701	2,697	32,581
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		220	220	220	220	220	220	219	218	218	217	217	217	2,626
13	Retail Demand-Related Recoverable Costs (I)		2,635	2,631	2,628	2,626	2,622	2,620	2,615	2,614	2,611	2,606	2,604	2,600	31,412
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,855	2,851	2,848	2,846	2,842	2,840	2,834	2,832	2,829	2,823	2,821	2,817	34,038

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) Smith 2.5% 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 Projected Period Amount
January 2010 - December 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1535, 1555, & 1819
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	
3	Less: Accumulated Depreciation (C)	(5,951,027)	(6,003,163)	(6,055,299)	(6,107,435)	(6,159,571)	(6,211,707)	(6,263,843)	(6,315,979)	(6,368,115)	(6,420,251)	(6,472,387)	(6,524,523)	(6,576,659)	
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)	10,241,197	10,189,061	10,136,925	10,084,789	10,032,653	9,980,517	9,928,381	9,876,245	9,824,109	9,771,973	9,719,837	9,667,701	9,615,565	
6	Average Net Investment		10,215,129	10,162,993	10,110,857	10,058,721	10,006,585	9,954,449	9,902,313	9,850,177	9,798,041	9,745,905	9,693,769	9,641,633	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		75,050	74,667	74,284	73,902	73,519	73,135	72,752	72,369	71,986	71,604	71,220	70,837	875,325
	b Debt Component (Line 6 x Debt Component x 1/12)		21,319	21,211	21,102	20,993	20,884	20,775	20,666	20,557	20,449	20,340	20,231	20,122	248,649
8	Investment Expenses														
	a Depreciation (E)		41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	501,888
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	123,744
	d Property Taxes		28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	345,372
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		177,286	176,795	176,303	175,812	175,320	174,827	174,335	173,843	173,352	172,861	172,368	171,876	2,094,978
	a Recoverable Costs Allocated to Energy		13,638	13,599	13,562	13,524	13,487	13,448	13,410	13,373	13,334	13,297	13,259	13,222	161,153
	b Recoverable Costs Allocated to Demand		163,648	163,196	162,741	162,288	161,833	161,379	160,925	160,470	160,018	159,564	159,109	158,654	1,933,825
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,166	13,139	13,100	13,092	13,057	13,019	12,983	12,942	12,904	12,848	12,796	12,759	155,805
13	Retail Demand-Related Recoverable Costs (I)		157,792	157,356	156,917	156,480	156,042	155,604	155,167	154,728	154,292	153,854	153,415	152,977	1,864,624
14	Total Juris. Recoverable Costs (Lines 12 + 13)		170,958	170,495	170,017	169,572	169,099	168,623	168,150	167,670	167,196	166,702	166,211	165,736	2,020,429

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) 3.1% 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 Projected Period Amount
January 2010 - December 2010

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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		124,950	124,500	124,950	124,950	124,950	124,950	124,950	124,950	124,950	124,950	124,950	126,000	
	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 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)	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	
3	Less: Accumulated Depreciation (C)	(21,927)	(22,207)	(22,487)	(22,767)	(23,047)	(23,327)	(23,607)	(23,887)	(24,167)	(24,447)	(24,727)	(25,007)	(25,287)	
4	CWIP - Non Interest Bearing	0	124,950	249,450	374,400	499,350	624,300	749,250	874,200	999,150	1,124,100	1,249,050	1,374,000	1,500,000	
5	Net Investment (Lines 2 + 3 + 4)	112,206	236,876	361,096	485,766	610,436	735,106	859,776	984,446	1,109,116	1,233,786	1,358,456	1,483,126	1,608,846	
6	Average Net Investment		174,541	298,986	423,431	548,101	672,771	797,441	922,111	1,046,781	1,171,451	1,296,121	1,420,791	1,545,986	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,283	2,196	3,111	4,027	4,944	5,859	6,775	7,691	8,607	9,523	10,439	11,358	75,813
	b Debt Component (Line 6 x Debt Component x 1/12)		364	625	883	1,144	1,405	1,664	1,925	2,184	2,445	2,705	2,965	3,227	21,536
8	Investment Expenses														
	a Depreciation (E)		280	280	280	280	280	280	280	280	280	280	280	280	3,360
	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)		1,927	3,101	4,274	5,451	6,629	7,803	8,980	10,155	11,332	12,508	13,684	14,865	100,709
	a Recoverable Costs Allocated to Energy		148	239	329	419	510	599	690	781	871	962	1,053	1,144	7,745
	b Recoverable Costs Allocated to Demand		1,779	2,862	3,945	5,032	6,119	7,204	8,290	9,374	10,461	11,546	12,631	13,721	92,964
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		143	231	318	406	494	580	668	756	843	930	1,017	1,104	7,490
13	Retail Demand-Related Recoverable Costs (I)		1,716	2,760	3,804	4,852	5,901	6,947	7,994	9,039	10,087	11,133	12,179	13,230	89,642
14	Total Juris. Recoverable Costs (Lines 12 + 13)		1,859	2,991	4,122	5,258	6,395	7,527	8,662	9,795	10,930	12,063	13,196	14,334	97,132

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) 2.5% 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 Projected Period Amount
January 2010 - December 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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	
	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		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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 Juris. 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 Projected Period Amount
January 2010 - December 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 1199, 1250, and 1287
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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) (J)	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	
3	Less: Accumulated Depreciation (C)	(20,754,277)	(21,143,930)	(21,533,583)	(21,923,236)	(22,312,889)	(22,702,542)	(23,092,195)	(23,481,848)	(23,871,501)	(24,261,154)	(24,650,807)	(25,040,460)	(25,430,113)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	113,926,836	113,537,183	113,147,530	112,757,877	112,368,224	111,978,571	111,588,918	111,199,265	110,809,612	110,419,959	110,030,306	109,640,653	109,251,000	
6	Average Net Investment		113,732,009	113,342,356	112,952,703	112,563,050	112,173,397	111,783,744	111,394,091	111,004,438	110,614,785	110,225,132	109,835,479	109,445,826	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		835,589	832,727	829,864	827,001	824,139	821,274	818,412	815,550	812,687	809,824	806,961	804,098	9,838,126
	b Debt Component (Line 6 x Debt Component x 1/12)		237,359	236,546	235,732	234,919	234,105	233,292	232,480	231,667	230,853	230,040	229,226	228,413	2,794,632
8	Investment Expenses														
	a Depreciation (E)		358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	4,304,172
	b Amortization (F)		2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	27,504
	c Dismantlement		28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	344,160
	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)		1,462,601	1,458,926	1,455,249	1,451,573	1,447,897	1,444,219	1,440,545	1,436,870	1,433,193	1,429,517	1,425,840	1,422,164	17,308,594
	a Recoverable Costs Allocated to Energy		1,462,601	1,458,926	1,455,249	1,451,573	1,447,897	1,444,219	1,440,545	1,436,870	1,433,193	1,429,517	1,425,840	1,422,164	17,308,594
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,411,950	1,409,541	1,405,686	1,405,243	1,401,741	1,398,117	1,394,713	1,390,495	1,386,916	1,381,214	1,376,134	1,372,358	16,734,108
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		1,411,950	1,409,541	1,405,686	1,405,243	1,401,741	1,398,117	1,394,713	1,390,495	1,386,916	1,381,214	1,376,134	1,372,358	16,734,108

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) Crist: 3.2% annually
(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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.'s 1272 & 1404
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	
3	Less: Accumulated Depreciation (C)	(89,630)	(92,135)	(94,640)	(97,145)	(99,650)	(102,155)	(104,660)	(107,165)	(109,670)	(112,175)	(114,680)	(117,185)	(119,690)	
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)	855,206	852,701	850,196	847,691	845,186	842,681	840,176	837,671	835,166	832,661	830,156	827,651	825,146	
6	Average Net Investment		853,953	851,448	848,943	846,438	843,933	841,428	838,923	836,418	833,913	831,408	828,903	826,398	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,274	6,256	6,237	6,219	6,200	6,182	6,164	6,145	6,127	6,108	6,090	6,072	74,074
	b Debt Component (Line 6 x Debt Component x 1/12)		1,782	1,777	1,772	1,767	1,761	1,756	1,751	1,746	1,740	1,735	1,730	1,725	21,042
8	Investment Expenses														
	a Depreciation (E)		2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	30,060
	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)		10,561	10,538	10,514	10,491	10,466	10,443	10,420	10,396	10,372	10,348	10,325	10,302	125,176
	a Recoverable Costs Allocated to Energy		812	811	809	807	805	803	802	800	798	796	794	792	9,629
	b Recoverable Costs Allocated to Demand		9,749	9,727	9,705	9,684	9,661	9,640	9,618	9,596	9,574	9,552	9,531	9,510	115,547
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		784	784	781	781	779	777	776	774	772	769	766	764	9,307
13	Retail Demand-Related Recoverable Costs (I)		9,400	9,379	9,358	9,337	9,315	9,295	9,274	9,253	9,231	9,210	9,190	9,170	111,412
14	Total Juris. Recoverable Costs (Lines 12 + 13)		10,184	10,163	10,139	10,118	10,094	10,072	10,050	10,027	10,003	9,979	9,956	9,934	120,719

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $919,836; Smith $25,000. Ending Balances: Crist $919,836; Smith $25,000.
(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 3.2% annually; Smith 2.5% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	(11,923)	(12,091)	(12,259)	(12,427)	(12,595)	(12,763)	(12,931)	(13,099)	(13,267)	(13,435)	(13,603)	(13,771)	(13,939)	
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)	50,947	50,779	50,611	50,443	50,275	50,107	49,939	49,771	49,603	49,435	49,267	49,099	48,931	
6	Average Net Investment		50,863	50,695	50,527	50,359	50,191	50,023	49,855	49,687	49,519	49,351	49,183	49,015	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		374	372	371	370	369	368	366	365	364	363	361	360	4,403
	b Debt Component (Line 6 x Debt Component x 1/12)		106	106	105	105	105	104	104	104	103	103	103	102	1,250
8	Investment Expenses														
	a Depreciation (E)		168	168	168	168	168	168	168	168	168	168	168	168	2,016
	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)		648	646	644	643	642	640	638	637	635	634	632	630	7,669
	a Recoverable Costs Allocated to Energy		648	646	644	643	642	640	638	637	635	634	632	630	7,669
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		626	624	622	622	622	620	618	616	614	613	610	608	7,415
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		626	624	622	622	622	620	618	616	614	613	610	608	7,415

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) 3.2% 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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010

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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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) (J)	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) (J)	(2,293,413)	(2,363,923)	(2,434,433)	(2,504,943)	(2,575,453)	(2,645,963)	(2,716,473)	(2,786,983)	(2,857,493)	(2,928,003)	(2,998,513)	(3,069,023)	(3,139,533)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (J)	27,546,265	27,475,755	27,405,245	27,334,735	27,264,225	27,193,715	27,123,205	27,052,695	26,982,185	26,911,675	26,841,165	26,770,655	26,700,145	
6	Average Net Investment		27,511,010	27,440,500	27,369,990	27,299,480	27,228,970	27,158,460	27,087,950	27,017,440	26,946,930	26,876,420	26,805,910	26,735,400	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		202,123	201,605	201,087	200,568	200,051	199,533	199,017	198,497	197,979	197,461	196,944	196,425	2,391,290
	b Debt Component (Line 6 x Debt Component x 1/12)		57,416	57,269	57,122	56,974	56,827	56,680	56,533	56,385	56,237	56,092	55,943	55,797	679,275
8	Investment Expenses														
	a Depreciation (E)		70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	846,120
	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)		330,049	329,384	328,719	328,052	327,388	326,723	326,060	325,392	324,726	324,063	323,397	322,732	3,916,685
	a Recoverable Costs Allocated to Energy		330,049	329,384	328,719	328,052	327,388	326,723	326,060	325,392	324,726	324,063	323,397	322,732	3,916,685
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		318,619	318,234	317,523	317,582	316,952	316,294	315,686	314,890	314,241	313,113	312,123	311,429	3,786,686
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		318,619	318,234	317,523	317,582	316,952	316,294	315,686	314,890	314,241	313,113	312,123	311,429	3,786,686

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $13,997,697; Smith $15,715,200; Scholz $126,781. Ending Balances: Crist $13,997,697; Smith $15,715,200; 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 3.2%; Smith 2.5%; Scholz 4.2% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E. 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		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	
14	Total Juris. Recoverable Costs (Lines 12 + 13)		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 3.2% annually; Scholz 4.2% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.'s 1227 & 1298
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		633,848	530,343	266,758	290,569	191,322	6,784,914	0	0	0	0	0	0	
	b Clearings to Plant (J)		633,848	530,343	266,758	290,569	191,322	6,784,914	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)	7,895,220	8,529,068	9,059,411	9,326,169	9,616,738	9,808,060	16,592,974	16,592,974	16,592,974	16,592,974	16,592,974	16,592,974	16,592,974	
3	Less: Accumulated Depreciation (C)	(19,551)	(41,453)	(64,907)	(89,424)	(114,684)	(140,587)	(175,793)	(220,046)	(264,299)	(308,552)	(352,805)	(397,058)	(441,311)	
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)	7,875,669	8,487,615	8,994,504	9,236,745	9,502,054	9,667,473	16,417,181	16,372,928	16,328,675	16,284,422	16,240,169	16,195,916	16,151,663	
6	Average Net Investment		8,181,642	8,741,059	9,115,624	9,369,399	9,584,763	13,042,327	16,395,054	16,350,801	16,306,548	16,262,295	16,218,042	16,173,789	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		60,111	64,221	66,973	68,837	70,419	95,822	120,455	120,130	119,804	119,479	119,154	118,828	1,144,233
	b Debt Component (Line 6 x Debt Component x 1/12)		17,075	18,243	19,024	19,554	20,003	27,220	34,216	34,125	34,032	33,940	33,847	33,755	325,034
8	Investment Expenses														
	a Depreciation (E)		21,902	23,454	24,517	25,260	25,903	35,206	44,253	44,253	44,253	44,253	44,253	44,253	421,760
	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	
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		99,088	105,918	110,514	113,651	116,325	158,248	198,924	198,508	198,089	197,672	197,254	196,836	1,891,027
	a Recoverable Costs Allocated to Energy		7,623	8,147	8,501	8,742	8,948	12,173	15,301	15,270	15,238	15,206	15,174	15,142	145,465
	b Recoverable Costs Allocated to Demand		91,465	97,771	102,013	104,909	107,377	146,075	183,623	183,238	182,851	182,466	182,080	181,694	1,745,562
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9679064	0.9670476	0.9670339	0.9655344	0.9644042	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		7,359	7,871	8,211	8,463	8,662	11,784	14,814	14,777	14,746	14,692	14,635	14,611	140,635
13	Retail Demand-Related Recoverable Costs (I)		88,192	94,272	98,363	101,155	103,535	140,848	177,052	176,681	176,308	175,937	175,564	175,192	1,683,099
14	Total Juris. Recoverable Costs (Lines 12 + 13)		95,551	102,143	106,574	109,618	112,197	152,632	191,866	191,458	191,054	190,629	190,209	189,803	1,823,734

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010

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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	12,500	12,500	12,500	12,500	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	50,000	
	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)	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	6,019,275	
3	Less: Accumulated Depreciation (C)	(689,408)	(705,328)	(721,248)	(737,168)	(753,088)	(769,008)	(784,928)	(800,848)	(816,768)	(832,688)	(848,608)	(864,528)	(880,514)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	12,500	25,000	37,500	0	
5	Net Investment (Lines 2 + 3 + 4)	5,279,867	5,263,947	5,248,027	5,232,107	5,216,187	5,200,267	5,184,347	5,168,427	5,152,507	5,149,087	5,145,667	5,142,247	5,138,761	
6	Average Net Investment		5,271,907	5,255,987	5,240,067	5,224,147	5,208,227	5,192,307	5,176,387	5,160,467	5,150,797	5,147,377	5,143,957	5,140,504	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		38,732	38,616	38,499	38,382	38,265	38,147	38,031	37,914	37,843	37,818	37,793	37,767	457,807
	b Debt Component (Line 6 x Debt Component x 1/12)		11,002	10,970	10,936	10,903	10,869	10,836	10,803	10,770	10,750	10,742	10,736	10,728	130,045
8	Investment Expenses														
	a Depreciation (E)		15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,986	191,106
	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)		65,654	65,506	65,355	65,205	65,054	64,903	64,754	64,604	64,513	64,480	64,449	64,481	778,958
	a Recoverable Costs Allocated to Energy		5,050	5,039	5,027	5,016	5,004	4,993	4,981	4,969	4,962	4,960	4,958	4,960	59,919
	b Recoverable Costs Allocated to Demand		60,604	60,467	60,328	60,189	60,050	59,910	59,773	59,635	59,551	59,520	59,491	59,521	719,039
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		4,876	4,869	4,856	4,856	4,845	4,834	4,823	4,809	4,802	4,792	4,785	4,786	57,933
13	Retail Demand-Related Recoverable Costs (I)		58,435	58,303	58,169	58,035	57,902	57,767	57,634	57,501	57,420	57,390	57,362	57,392	693,310
14	Total Juris. Recoverable Costs (Lines 12 + 13)		63,311	63,172	63,025	62,891	62,747	62,601	62,457	62,310	62,222	62,182	62,147	62,178	751,243

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) 3.2% 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance Program
P.E.s 1034, 1035, 1036, 1037, 1095, 1222, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1810, 1824, & 1826
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		2,739,363	1,543,197	1,567,770	517,669	375,543	282,275	131,864	573	423	423	423	423	
	b Clearings to Plant (J)		2,512,374	1,004,536	1,010,500	131,500	56,733	3,834,289	131,864	573	423	423	423	423	
	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	100,000	
2	Plant-in-Service/Depreciation Base (B) (K)	608,014,996	610,527,370	611,531,906	612,542,406	612,673,906	612,728,639	616,562,928	616,694,792	616,695,365	616,695,788	616,696,211	616,696,634	616,697,057	
3	Less: Accumulated Depreciation (C)	(4,734,904)	(6,357,272)	(7,984,330)	(9,614,075)	(11,245,343)	(12,876,859)	(14,513,403)	(16,155,071)	(17,796,910)	(19,438,730)	(21,080,591)	(22,722,434)	(24,264,278)	
4	CWIP - Non Interest Bearing	2,964,689	3,191,678	3,730,339	4,287,609	4,673,778	4,994,588	1,442,574	1,442,574	1,442,574	1,442,574	1,442,574	1,442,574	1,442,574	
5	Net Investment (Lines 2 + 3 + 4)	606,244,781	607,361,776	607,277,915	607,215,940	606,102,341	604,846,368	603,492,099	601,982,295	600,341,029	598,699,632	597,058,194	595,416,774	593,875,353	
6	Average Net Investment		606,803,279	607,319,846	607,246,928	606,659,141	605,474,355	604,169,234	602,737,197	601,161,662	599,520,321	597,878,903	596,237,484	594,646,064	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,458,184	4,461,979	4,461,444	4,457,125	4,448,420	4,438,832	4,428,310	4,416,735	4,404,676	4,392,617	4,380,557	4,368,865	53,117,744
	b Debt Component (Line 6 x Debt Component x 1/12)		1,266,400	1,267,477	1,267,325	1,266,098	1,263,626	1,260,901	1,257,913	1,254,625	1,251,200	1,247,774	1,244,348	1,241,027	15,088,714
8	Investment Expenses														
	a Depreciation (E)		1,613,028	1,617,718	1,620,405	1,621,928	1,622,176	1,627,304	1,632,328	1,632,499	1,632,500	1,632,501	1,632,503	1,632,504	19,517,294
	b Amortization (F)		9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	112,080
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	117,324
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,356,729	7,366,291	7,368,291	7,364,268	7,353,339	7,346,054	7,337,668	7,322,976	7,307,493	7,292,009	7,276,525	7,261,513	87,953,156
	a Recoverable Costs Allocated to Energy		7,356,729	7,366,291	7,368,291	7,364,268	7,353,339	7,346,054	7,337,668	7,322,976	7,307,493	7,292,009	7,276,525	7,261,513	87,953,156
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		7,101,961	7,116,941	7,117,340	7,129,225	7,118,929	7,111,559	7,104,210	7,086,624	7,071,541	7,045,613	7,022,861	7,007,200	85,034,004
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		7,101,961	7,116,941	7,117,340	7,129,225	7,118,929	7,111,559	7,104,210	7,086,624	7,071,541	7,045,613	7,022,861	7,007,200	85,034,004

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $592,369,378; Smith $11,389,634; Daniel $3,932,561, Scholz $663,423. Ending Balances: Crist $597,134,211; Smith $11,389,634, Daniel $7,509,789, Scholz $663,423.
(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: 3.2%, Plant Smith Steam 2.5%, Smith CT 0.4%, Daniel 3.1%, Scholz 4.2%. Portion of PE 1222 is transmission 2.2%, 2.3%, 4.1%, 2.6%.
(F) Portion of PE 1222 has a 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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E. 1280
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	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)	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	
3	Less: Accumulated Depreciation (C)	(9,459)	(9,853)	(10,247)	(10,641)	(11,035)	(11,429)	(11,823)	(12,217)	(12,611)	(13,005)	(13,399)	(13,793)	(14,187)	
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)	14,195	13,801	13,407	13,013	12,619	12,225	11,831	11,437	11,043	10,649	10,255	9,861	9,467	
6	Average Net Investment		13,998	13,604	13,210	12,816	12,422	12,028	11,634	11,240	10,846	10,452	10,058	9,664	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		103	100	97	94	91	88	85	83	80	77	74	71	1,043
	b Debt Component (Line 6 x Debt Component x 1/12)		29	28	28	27	26	25	24	23	23	22	21	20	296
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		394	394	394	394	394	394	394	394	394	394	394	394	4,728
	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)		526	522	519	515	511	507	503	500	497	493	489	485	6,067
	a Recoverable Costs Allocated to Energy		40	40	40	40	39	39	39	38	38	38	38	37	466
	b Recoverable Costs Allocated to Demand		486	482	479	475	472	468	464	462	459	455	451	448	5,601
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		39	39	39	39	38	38	38	37	37	37	37	36	454
13	Retail Demand-Related Recoverable Costs (I)		469	465	462	458	455	451	447	445	443	439	435	432	5,401
14	Total Juris. Recoverable Costs (Lines 12 + 13)		508	504	501	497	493	489	485	482	480	476	472	468	5,855

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 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 Projected Period Amount
January 2010 - December 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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 Balance		0	0	0	0	0	0	0	0	0	0	0	0	
	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		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		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	
14	Total Juris. Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Based on ROE of 12% and weighted income tax rate of 38.575%
(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 3P
(E) Line 8 is reported on Schedule 2P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Annual NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments														
	a Purchases/Transfers		495,000	837,500	1,425,000	0	1,590,000	2,165,000	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 Balance		0	0	0	0	0	0	0	0	0	0	0	0	
	a FERC 158.1 Allowance Inventory	3,315,044	1,609,508	2,289,738	3,513,487	3,213,893	4,462,218	6,078,088	5,253,184	4,401,929	3,634,849	2,852,398	2,145,337	1,414,122	
	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	3,315,044	1,609,508	2,289,738	3,513,487	3,213,893	4,462,218	6,078,088	5,253,184	4,401,929	3,634,849	2,852,398	2,145,337	1,414,122	
4	Average Net Working Capital Balance		2,462,276	1,949,623	2,901,612	3,363,690	3,838,056	5,270,153	5,665,636	4,827,557	4,018,389	3,243,623	2,498,867	1,779,729	
5	Return on Average Net Working Capital Balance														
	~~a Equity Component (Line 4 x Equity Component x 1/12)(A)~~	~~18,090~~	~~14,324~~	~~21,318~~	~~24,713~~	~~28,198~~	~~38,720~~	~~41,625~~	~~35,468~~	~~29,523~~	~~23,831~~	~~18,359~~	~~13,076~~	~~307,245~~	
	b Debt Component (Line 4 x Debt Component x 1/12)	5,139	4,069	6,056	7,020	8,010	10,999	11,824	10,075	8,386	6,769	5,215	3,714	87,276	
6	Total Return Component (D)	23,229	18,393	27,374	31,733	36,208	49,719	53,449	45,543	37,909	30,600	23,574	16,790	394,521	
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	2,200,537	157,270	201,251	299,594	341,674	549,130	824,904	851,254	767,080	782,451	707,061	731,215	8,413,422	
8	Net Expenses (E)	2,200,537	157,270	201,251	299,594	341,674	549,130	824,904	851,254	767,080	782,451	707,061	731,215	8,413,422	
9	Total System Recoverable Expenses (Lines 6 + 8)	2,223,766	175,663	228,625	331,327	377,882	598,849	878,353	896,797	804,989	813,051	730,635	748,005	8,807,943	
	a Recoverable Costs Allocated to Energy	2,223,766	175,663	228,625	331,327	377,882	598,849	878,353	896,797	804,989	813,051	730,635	748,005	8,807,943	
	b Recoverable Costs Allocated to Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)	2,146,755	169,716	220,839	320,752	365,836	579,733	850,407	867,853	778,997	785,579	705,164	721,808	8,513,439	
13	Retail Demand-Related Recoverable Costs (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
14	Total Juris. Recoverable Costs (Lines 12 + 13)	2,146,755	169,716	220,839	320,752	365,836	579,733	850,407	867,853	778,997	785,579	705,164	721,808	8,513,439	

Notes:
(A) Based on ROE of 12% and weighted income tax rate of 38.575%
(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 3P
(E) Line 8 is reported on Schedule 2P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Seasonal NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	181,272	180,726	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 Balance		0	0	0	0	0	0	0	0	0	0	0	0	
	a FERC 158.1 Allowance Inventory	67,424	67,424	67,424	67,424	67,424	53,667	219,994	318,241	150,913	(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	67,424	67,424	67,424	67,424	67,424	53,667	219,994	318,241	150,913	(0)	(0)	(0)	(0)	
4	Average Net Working Capital Balance		67,424	67,424	67,424	67,424	60,545	136,831	269,118	234,577	75,456	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12)(A)		495	495	495	495	445	1,005	1,977	1,723	554	0	0	0	7,684
	b Debt Component (Line 4 x Debt Component x 1/12)		141	141	141	141	126	286	562	490	157	0	0	0	2,185
6	Total Return Component (D)		636	636	636	636	571	1,291	2,539	2,213	711	0	0	0	9,869
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	13,757	14,944	82,480	167,328	150,913	0	0	0	429,422
8	Net Expenses (E)		0	0	0	0	13,757	14,944	82,480	167,328	150,913	0	0	0	429,422
9	Total System Recoverable Expenses (Lines 6 + 8)		636	636	636	636	14,328	16,235	85,019	169,541	151,624	0	0	0	439,291
	a Recoverable Costs Allocated to Energy		636	636	636	636	14,328	16,235	85,019	169,541	151,624	0	0	0	439,291
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		614	614	614	616	13,871	15,717	82,314	164,069	146,728	0	0	0	425,157
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		614	614	614	616	13,871	15,717	82,314	164,069	146,728	0	0	0	425,157

Notes:
(A) Based on ROE of 12% and weighted income tax rate of 38.575%
(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 3P
(E) Line 8 is reported on Schedule 2P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010
Return on Capital Investments, Depreciation and Taxes
For Project: SO_2 Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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 Balance		0	0	0	0	0	0	0	0	0	0	0	0	
	a FERC 158.1 Allowance Inventory	11,211,121	10,870,694	10,648,304	10,476,406	10,301,005	10,100,120	9,864,471	9,608,069	9,341,597	9,097,980	8,848,146	8,612,760	8,370,807	
	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	(985,309)	(978,915)	(972,521)	(966,126)	(959,732)	(953,337)	(946,943)	(940,549)	(934,154)	(927,760)	(921,366)	(914,971)	(908,577)	
3	Total Working Capital Balance	10,225,812	9,891,779	9,675,783	9,510,280	9,341,273	9,146,782	8,917,528	8,667,521	8,407,443	8,170,220	7,926,780	7,697,789	7,462,230	
4	Average Net Working Capital Balance		10,058,795	9,783,781	9,593,031	9,425,777	9,244,028	9,032,155	8,792,525	8,537,482	8,288,831	8,048,500	7,812,285	7,580,010	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12)(A)		73,902	71,881	70,480	69,251	67,916	66,359	64,599	62,725	60,898	59,132	57,397	55,690	780,230
	b Debt Component (Line 4 x Debt Component x 1/12)		20,993	20,419	20,021	19,672	19,292	18,850	18,350	17,818	17,299	16,797	16,304	15,819	221,634
6	Total Return Component (D)		94,895	92,300	90,501	88,923	87,208	85,209	82,949	80,543	78,197	75,929	73,701	71,509	1,001,864
7	Expenses:														
	a Gains		(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(76,733)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		340,427	222,390	171,898	175,401	200,886	235,648	256,402	266,472	243,617	249,834	235,385	241,953	2,840,314
8	Net Expenses (E)		334,032	215,996	165,504	169,006	194,491	229,254	250,008	260,078	237,223	243,440	228,991	235,559	2,763,581
9	Total System Recoverable Expenses (Lines 6 + 8)		428,927	308,296	256,005	257,929	281,699	314,463	332,957	340,621	315,420	319,369	302,692	307,068	3,765,445
	a Recoverable Costs Allocated to Energy		428,927	308,296	256,005	257,929	281,699	314,463	332,957	340,621	315,420	319,369	302,692	307,068	3,765,445
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		414,073	297,860	247,285	249,697	272,719	304,425	322,363	329,627	305,235	308,578	292,140	296,314	3,640,316
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Juris. Recoverable Costs (Lines 12 + 13)		414,073	297,860	247,285	249,697	272,719	304,425	322,363	329,627	305,235	308,578	292,140	296,314	3,640,316

Notes:
(A) Based on ROE of 12% and weighted income tax rate of 38.5756%
(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 3P
(E) Line 8 is reported on Schedule 2P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 and the trailer was replaced in 2005. 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 $220,294 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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

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 $14,531,879 projected at December 2010.

Progress Summary: In-Service

Projections: During the 2010 recovery period, Plant Crist plans to begin incurring preliminary engineering and design costs to rebuild portions of the Crist Unit 6 precipitator. Recent inspections of the Plant Crist Unit 6 precipitator have indicated that the internals will need to be replaced by 2013. The 2010 projected expenditures for the Plant Crist Unit 6 precipitator project are $1.1 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010-December 2010

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 in the combustion process. This equipment was installed to meet the requirements of the 1990 Clean Air Act Amendments.

Accomplishments:
The Low NO_x burner system has proven effective in reducing NO_x emissions. The low NO_x burners on Crist Unit 7 were replaced during 2003-2004 time frame and the Crist Unit 6 burners were replaced during December 2005.

Project-to-Date: Plant-in-service of $9,097,923 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CEMs – Plant Crist, Scholz, Smith, and Daniel
PEs 1001, 1154, 1164, 1217, 1240, 1245, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 1558, 1570, 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 $4,021,796 projected at December 2010.

Progress Summary:
Crist 4, 5, 6 and 7 CEMS equipment replacements (gas analyzers, opacity monitors, and common CEMS equipment), Scholz 1 & 2 CEMS analyzer replacements, and Smith 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 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 2009, the CEMs project includes the replacement of opacity monitors at Plant Crist on Units 4 and 5 and the installation of CEMs equipment for the new Plant Crist scrubber stack. CEMs equipment will be installed in the scrubber stack to monitor SO_2, NOx, CO_2 and flow pursuant to the CAAA. The 2009 scrubber CEMs expenditures include a new CEMs shelter as well as the monitoring equipment.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Substation Contamination Mobile Groundwater Treatment System
PEs 1007, 3400, and 3412

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 $918,024 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 $242,972 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 1-5 Dechlorination
PE 1248

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
State and Federal Pollution Discharge Elimination System permits require significant reductions in chlorine discharge from the plant. The Crist Units 1-5 dechlorination system injects sodium bisulfite into the cooling water canal to chemically eliminate the residual chlorine present in the plant discharge effluent.

Accomplishments:
The system has been effective in maintaining chlorine discharge limits.

Project-to-Date: Plant-in-service of $305,323 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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:
Monitoring wells were installed 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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 address deficiencies identified during the August 1992 Plant Crist Environmental Audit and 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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 waste water 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 includes aeration and chlorination of the waste water prior to discharge in the Plant Smith ash pond.

Accomplishments: Plant Smith has maintained compliance with the NPDES industrial wastewater permit domestic wastewater treatment requirements.

Project-to-Date: Plant-in-service of $178,962 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Daniel Ash Management Project
PEs 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: No reportable exceedances have occurred since system installation. Construction of the new on-site ash storage facility was completed in 2006.

Project-to-Date: Plant-in-service of $16,192,224 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Water Conservation
PEs 1601, 1620, and 1638

FPSC Approval: Order No. PSC-01-1788-FOF-EI

Description:
This project is a water conservation and consumptive use efficiency program to reduce the demand for groundwater and the potential for saltwater intrusion. Plant Smith's individual water use permit issued by the Northwest Florida Water Management District includes a specific condition requesting a 25% reduction in the use of groundwater. 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.

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 $134,133 projected at December 2010.

Progress Summary: In-Service

Projections: Gulf is currently investigating the feasibility of utilizing reclaimed water at Plant Smith for the Unit 3 cooling tower which would reduce surface water consumption by 5 to 6 million gallons per day. The project expenses have been and will continue to be booked to a preliminary investigation account until Gulf determines whether or not it is able to move forward with the project. If it is feasible to move forward with the project, approximately $1.5 million is projected to be incurred for engineering and design of the infrastructure required to re-use this beneficial water source.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist FDEP Agreement for Ozone Attainment
PEs 1031, 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.

Project-to-Date: Plant-in-service of $134,681,113 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SPCC Compliance
PEs 1272 & 1401

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The SPCC Compliance projects were required as the result of a more stringent July 17, 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 recent 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: Construction on the Plant Crist switchyard sump was completed during 2006. The sump was designed to route stormwater from the switchyard drains to a new oil skimming sump where any potential spill(s) would be captured, preventing the oil from reaching surface water. During 2009, Plant Smith installed secondary containment for a small fuel tank and a padmount transformer.

Project-to-Date: Plant-in-service of $944,836 projected at December 2010.

Progress Summary: In-service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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. The purchase of this instrument enabled Gulf Power to measure ammonia slip emissions as required by the Crist Unit 7 Selective Catalytic Reduction (SCR) air construction permit.

Accomplishments: The FTIR is fully operational.

Project-to-Date: Plant-in-service of $62,870 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Precipitator Upgrades for Compliance Assurance Monitoring
PEs 1175, 1191, 1305, 1461, and 1462

FPSC Approval: Order No. PSC-04-1187-FOF-EI

Description: Compliance Assurance Monitoring (CAM) Precipitator Upgrades are required to comply with the 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 2010.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 Scholz project has been delayed until Gulf receives FDEP's formal response to the Plant Scholz groundwater study. The Plant Crist project has been canceled because Gulf has been released from any remedial action at this site.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Crist Water Conservation Project
PEs 1227 & 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 (NWFWMD) 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. Gulf Power has entered into an agreement with the Emerald Coast Utilities Authority (ECUA) to begin utilizing reclaimed water from ECUA's proposed wastewater treatment to reduce the demand for groundwater and surface water withdrawals. The NWFWMD 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.

Project-to-Date: Plant-in-service of $16,592,974 projected at December 2010.

Progress Summary: See Accomplishments

Projections: Gulf expects $7.9 million of equipment to be placed in-service during December of 2009 to connect the Plant Crist scrubber project to the ECUA potable water system. Expenditures totaling $8.7 million are projected to be incurred for portions of the Plant Crist Water Conservation project that will be placed-in-service during 2010.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant 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 also installed a chemical treatment system to reduce iron and copper concentrations in the ash pond discharge.

Project-to-Date: Plant-in-service of $6,019,275 projected at December 2010.

Progress Summary: In-Service

Projections: Gulf expects to incur approximately $50,000 of expenditures during 2010 to install an aeration system to reduce copper concentrations in the ash pond discharge.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CAIR / CAMR/CAVR Compliance Program
PEs 1034, 1035, 1036, 1037, 1095, 1222, 1362, 1468, 1469, 1512, 1513, 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 the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and 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 $616,697,057 projected at December 2010.

Progress Summary: See Accomplishments

Projections:
For the purpose of the 2010 projection of ECRC revenue requirements, $8.7 million is projected to be cleared to plant-in-service for the CAIR/CAMR/CAVR Compliance Program. This placed-in-service amount includes expenditures that will be made during 2010 as well as previous years. The two capital projects included in the Compliance Program that will impact the 2010 ECRC revenue requirements are the Plant Crist Units 4 through 7 scrubber ($4.8 million) and the Plant Daniel Unit 1 Low NOx burners ($3.9 million).

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 have new conditions which require 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 $23,654 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 Plan.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 / CAMR 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 and CAVR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:

Gulf began surrendering annual NOx allowances during 2009.

Projections:

Gulf currently has forward contracts in place to purchase $6.5 million of annual NOx allowances during 2010.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 CAMR 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 and CAVR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:

Gulf began surrendering seasonal NOx allowances during 2009.

Projections: Gulf is currently projecting the need to purchase approximately $362,000 seasonal NOx allowances during 2010.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 has 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 purchased SO_2 allowances during the 2006, 2007 and 2009.

Project-to-Date: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010-December 2010

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 IV of the 1990 Clean Air Act Amendments.

Accomplishments:
Fees have been paid by due dates.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $916,374

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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).

Accomplishments:
Title V permits for Plants Crist, Smith, and Scholz were issued by FDEP in 1999. The Title V permit for the Pea Ridge generating facility was issued in July, 2000. In May 2009, the Title V renewal applications were submitted for Plant Crist, Smith, Scholz and Pea Ridge. New Title V air operating permits for all of Gulf's generating facilities are expected in December, 2009.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $126,436

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $2,600

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $559,914

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 and the Impaired Waters Rule.

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: $441,707

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 for 50 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,630,452

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $42,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $21,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $12,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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) compliance plan.

Accomplishments:
Gulf has complied with all hazardous and solid waste regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $558,133

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $98,387

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010-December 2010

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 additional 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. Plant Crist plans to replace the existing ash curtains and dredge the pond during 2009.

Accomplishments:
Ash pond diversion curtains have been installed at Plant Crist.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 project refers to the sodium injection systems at Plant Smith and Plant Crist. The activity involves sodium injection to the coal supply to enhance precipitator efficiencies when burning low sulfur coal.

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: $242,989

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 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 2010-December 2010

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:
On July 17, 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 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 2010-December 2010

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 7 Selective Catalytic Reduction (SCR) and Crist Units 4, 5, and 6 Selective 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, and general operation and maintenance expenses are included in this line item.

Accomplishments: The Crist Unit 7 SCR and the Crist Units 4, 5, and 6 SNCRs are fully operational.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $2,647,500

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.20

Title: CAIR/CAMR/CAVR Compliance Plan

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, and 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:
Gulf began incurring O&M expenses associated with the Crist Units 4 through 7 scrubber, Smith Units 1 and 2 SNCRs, and Scholz mercury monitoring system during 2009.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $20,729,607

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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)

Description: EPA recently proposed an extensive Information Collection Request (ICR) in the Federal Register 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). EPA is currently accepting comments on this proposal and is expected to finalize the ICR in January 2010. The ICR will require 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 25 MW. The proposed ICR also requires each of Gulf's facilities to conduct a broad range of emissions testing.

Accomplishments: N/A

Fiscal Expenditures: N/A

Progress Summary: N/A

Projections: $541,000.

Schedule 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2010 - December 2010

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Jan - Dec. 2010 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	58.020395%	5,571,241,000	1,096,142.86	1.0048648	1.0053010	5,600,773,981	1,101,475.33	49.79563%	58.83889%
GS	63.781436%	313,549,000	56,118.62	1.0048589	1.0052978	315,210,104	56,391.29	2.80248%	3.01232%
GSD, GSDT, GSTOU	75.860452%	2,435,322,000	366,468.68	1.0047057	1.0051660	2,447,902,971	368,193.15	21.76393%	19.66823%
LP, LPT	86.886296%	1,885,643,000	247,744.54	0.9842260	0.9891199	1,865,126,997	243,836.61	16.58256%	13.02532%
PX, PXT, RTP, SBS	104.683592%	883,147,000	96,305.32	0.9744382	0.9805725	865,989,688	93,843.58	7.69938%	5.01296%
OS-I/II	321.885641%	115,537,000	4,097.47	1.0046893	1.0052949	116,148,751	4,116.68	1.03266%	0.21991%
OS-III	99.718369%	36,179,000	4,141.69	1.0051151	1.0052683	36,369,601	4,162.88	0.32336%	0.22237%
TOTAL		11,240,618,000	1,871,019.18			11,247,522,093	1,872,019.52	100.00000%	100.00000%

Notes:
(1) Average 12 CP load factor based on actual 2006 load research data
(2) Projected KWH sales for the period January 2010 - December 2010
(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. 010949-EI
(5) Based on energy losses identified in Docket No. 010949-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 2010 - December 2010

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	49.79563%	58.83889%	73,117,464	4,370,738	77,488,202	5,571,241,000	1.391
GS	2.80248%	3.01232%	4,115,024	223,765	4,338,789	313,549,000	1.384
GSD, GSDT, GSTOU	21.76393%	19.66823%	31,957,089	1,461,018	33,418,107	2,435,322,000	1.372
LP, LPT	16.58256%	13.02532%	24,349,019	967,562	25,316,581	1,885,643,000	1.343
PX, PXT, RTP, SBS	7.69938%	5.01296%	11,305,392	372,379	11,677,771	883,147,000	1.322
OS-I, OS-II	1.03266%	0.21991%	1,516,307	16,336	1,532,643	115,537,000	1.327
OS-III	0.32336%	0.22237%	474,806	16,518	491,324	36,179,000	1.358
TOTAL	100.00000%	100.00000%	$146,835,101	$7,428,316	$154,263,417	11,240,618,000	1.372

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 2010 - December 2010
(7) Col 5 / Col 6 x 100