BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080007-EI

In the Matter of

ENVIRONMENTAL COST RECOVERY CLAUSE.

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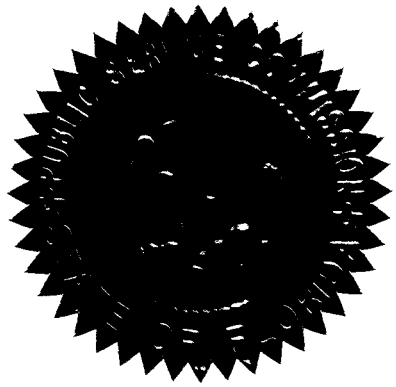

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN MATTHEW M. CARTER, II COMMISSIONER LISA POLAK EDGAR COMMISSIONER KATRINA J. McMURRIAN COMMISSIONER NANCY ARGENZIANO COMMISSIONER NATHAN A. SKOP
DATE:	Tuesday, November 4, 2008
TIME:	Commenced at 9:30 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

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APPEARANCES:

LEE L. WILLIS, ESQUIRE and JAMES D. BEASLEY, ESQUIRE, Ausley Law Firm, Post Office Box 391, Tallahassee, 32302, appearing on behalf of Tampa Electric Company.

JEFFREY STONE, ESQUIRE, RUSSELL BADDERS, ESQUIRE, and STEVEN GRIFFIN, ESQUIRE, Beggs & Lane Law Firm, Post Office Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

JOHN W. MCWHIRTER, JR., ESQUIRE, c/o McWhirter Law Firm, Post Office Box 3350, Tampa, Florida 33601-3350, appearing on behalf of Florida Industrial Power Users Group.

JOHN T. BUTLER, ESQUIRE, and WADE LITCHFIELD, ESQUIRE, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

GARY V. PERKO, ESQUIRE, Hopping Law Firm, Post Office Box 6526, Tallahassee, Florida 32314, appearing on behalf of Progress Energy Florida, Inc.

PATRICIA CHRISTENSEN, ESQUIRE, and STEPHEN BURGESS, ESQUIRE, and JOE MCGLOTHLIN, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison St., #812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of Florida.

APPEARANCES (continued):

JOHN T. BURNETT, Progress Energy Service Co., LLC, Post Office Box 14042, St. Petersburg, Florida 33733-4042, appearing on behalf of Progress Energy Florida, Inc.

KAREN S. WHITE, ESQUIRE, and CAPTAIN SHAYLA L. McNEILL, ESQUIRE, AFCESA/ULT, 139 Barnes Drive, Suite 1, Tyndall Air Force Base, Florida 32403, appearing on behalf of the Federal Executive Agencies.

MARTHA BROWN, ESQUIRE, and ERIK L. SAYLER, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

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P R O C E E D I N G S

CHAIRMAN CARTER: I will give one second now for staff to make a little adjustment here.

Next, Commissioners, we will be on Docket Number 080007-EI. Docket Number 080007-EI.

Staff, you're recognized.

MS. BROWN: Mr. Chairman, there are proposed stipulations on all issues in this docket and all witnesses have been excused. Parties do not intend to make any opening statements. We ask that the prefiled testimony of all witnesses identified in Section VI of the prehearing order be inserted into the record as though read. Cross examination has been waived.

CHAIRMAN CARTER: The prefiled testimony of the witnesses will be entered into the record as though read.

MS. BROWN: Staff has prepared a Comprehensive Exhibit List, and we ask that you mark and move the stipulated exhibit list into the record as numbered 1 through 27 on the list.

CHAIRMAN CARTER: Any objections? Without objection, show it done.

(Exhibit Numbers 1 through 27 marked for identification and admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 080007-EI

APRIL 2, 2008

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as the Senior Manager of Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in the predecessors to this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the Environmental Cost Recovery (ECR) Clause true-up costs associated with FPL Environmental Compliance activities for the period January through December 2007.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. My Exhibit KMD-1 consists of eight forms.

- Form 42-1A reflects the final true-up for the period January through December 2007.
- Form 42-2A consists of the final true-up calculation for the period.
- Form 42-3A consists of the calculation of the interest provision for the period.
- Form 42-4A reflects the calculation of variances between actual and estimated/actual costs for O&M Activities.
- Form 42-5A presents a summary of actual monthly costs for the period for O&M Activities.
- Form 42-6A reflects the calculation of variances between actual and estimated/actual costs for Capital Investment Projects.
- Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects.
- Form 42-8A consists of the calculation of depreciation expense and return on capital investment. Form 42-8A, Pages 41 through 43 provide the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each Capital Investment Project.

Q. What is the source of the actuals data which you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actuals data are taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, and with the provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Please explain the calculation of the Net True-up Amount.

A. Form 42-1A, entitled "Calculation of the Final True-up" shows the calculation of the Net True-Up for the period January 2007 through December 2007, an over-recovery of $3,174,379, which I am requesting to be included in the calculation of the ECR factors for the January through December 2009 period.

The actual End-of-Period over-recovery for the period January through December 2007 of $2,588,553 (shown on Form 42-1A, line 3) adjusted for the estimated/actual End-of-Period under-recovery for the same period of $585,826 (shown on Form 42-1A, line 6) results in the Net True-Up over-recovery for the period January through December 2007 (shown on Form 42-1A, line 7) of $3,174,379.

Q. Have you provided a schedule showing the calculation of the End-of-Period true-up?

A. Yes. Form 42-2A, entitled "Calculation of Final True-up Amount", shows the calculation of the Environmental End of Period true-up for the period January through December 2007. The End of Period true-up shown on page 2 of 2, Lines 5 plus 6 is an over-recovery of $2,588,553. Additionally, Form 42-3A shows the calculation of the Interest Provision of $638,465 which is applicable to end of period true-up over-recovery of $2,588,553.

Q. Is the true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by the Commission as set forth on Commission Schedule A-2 "Calculation of the True-Up and Interest Provisions" for the Fuel Cost Recovery Clause.

Q. Are all costs listed in Forms 42-4A through 42-8A attributable to Environmental Compliance Projects approved by the Commission?

A. Yes, they are.

Q. How did actual expenditures for January through December 2007 compare with FPL's estimated/actual projections as presented in previous testimony and exhibits?

A. Form 42-4A shows that total O&M project costs were $2,899,662, or 16.0% lower than projected and Form 42-6A shows that total capital investment project costs were $410,405 or 1.7% lower than projected. Following are explanations for those O&M Projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4A and 42-6A. Return on Capital Investment, Depreciation and Taxes for each project for the actual period January through December 2007 are provided on Form 42-8A.

Q. Please explain the reasons for these variances.

A. The variances in FPL's 2007 O&M expenses and capital expenditures for primarily relate to the following projects:

1. Maintenance of Stationary Above Ground Fuel Storage Tanks - O & M (Project 5a)

Project expenditures were $336,834, or 15.0% higher than anticipated. The variance is primarily due to work on the Turkey Point Unit 2 metering tank. During the disposal of water in the tank, mercury was discovered and required offsite disposal. Additionally, bids received for the painting work on the Martin tank were higher than the original estimates.

2. Disposal of Non-containerized Liquid Waste – O & M (Project 17a)

Project expenditures were $33,813, or 11.6% lower than anticipated. Use of the ash press at Turkey Point that was scheduled for late 2007 was pushed back to the first quarter 2008 due a Resource Conservation and Recovery Act (RCRA) Facility Evaluation that occurred in November 2007. Additionally, Manatee and Martin plant ash basins had decreased levels of ash due to the lower burn of fuel oil, and therefore the basins did not require ash pressing.

3. Substation Pollutant Discharge Prevention & Removal – Distribution - O&M (Project 19a)

Project expenditures were $177,313, or 15.4% lower than anticipated. Planned project encapsulation related work activities were reduced due to equipment replacement and/or removal. In addition, a portion of the distribution encapsulation work activity was deferred to 2008 due to difficulties in acquiring clearances. Finally, a portion of planned soil and groundwater remediation work activities were deferred to 2008 pending agency approval.

4. Substation Pollutant Discharge Prevention & Removal - Transmission - O&M (Project 19b)

Project expenditures were $71,337, or 38.3% lower than anticipated. Planned work was postponed due to an internal review of transformer

isolation and testing procedures.

5. Pipeline Integrity Management (PIM) – O&M (Project 22)

Project expenditures were $284,981, or 65.0% higher than anticipated. The variance is primarily due to an increase in the quality of materials specified for the Manatee Terminal pipe coating job. This higher specification will extend the life of the paint used to coat the pipe, resulting in less maintenance and repair cost.

6. Spill Prevention, Control & Countermeasures - SPCC – O&M (Project 23)

Project expenditures were $79,171, or 25.2% lower than anticipated. On May 10, 2007 the United States Environmental Protection Agency (EPA) extended the compliance date for amending SPCC plans and implementing modifications to July 1, 2009. Planned physical modifications were put on hold due to management review of regulatory requirements in relation to current situations with facilities in the field.

7. Manatee Reburn – O&M (Project 24)

Project expenditures were $64,319, or 14.0% lower than anticipated. Reburn burner maintenance inspections at the Manatee plant revealed less damage than anticipated. Reburn equipment is relatively new, and failure rates remain lower than expected.

8. Port Everglades Electrostatic Precipitator (ESP) – O & M (Project 25)

Project expenditures were $169,615, or 13.8% lower than anticipated. Due to the relative cost to FPL of oil and gas, less oil and more gas was burned than originally expected at the plant and, as a result, less O&M activities were needed for the ESPs. This decreased usage of oil also contributed to less ash being produced. Finally, the failure rates of ESP equipment have proven to be lower than originally expected (more reliable), thus requiring less maintenance.

9. Lowest Quality Water Source (LQWS) – O&M (Project 27)

Project expenditures were $114,980, or 31.2% lower than anticipated. Based upon the results of an internal feasibility study and pilot project to assess the feasibility of using reclaimed water at the Cape Canaveral plant, and due to several issues including reclaimed water quality, water treatment system costs and current operations conditions, a determination was made that the use of reclaimed water at the this facility was not economically, environmentally or technologically feasible. Additionally, the Pre-Treatment System at the Sanford plant was not utilized due to maintenance issues. During this time, 100% ground water was used, which requires no treatment.

10. Clean Air Interstate Rule (CAIR) Compliance – O & M (Project 31)

Project expenditures were $351,334, or 93.4% higher than expected. The variance is primarily due to the accelerated completion of test ports and probe supports for the CAIR Continuous Emissions Monitoring Systems (CEMS) project at Lauderdale and Ft Myers plants, which included fabrication and installation. Due to the requirement that 12 months of CEMS data be available by January 2009, the installation of equipment was necessary before 2008.

11. Best Available Retrofit Technology (BART) – O & M (Project 32)

Project expenditures were $13,440, or 395.6% higher than expected. The original estimate did not include $13,440 for contractor hours supporting the development of inputs and methodology for the BART evaluation, which was required as a result of a request from the Department of Environmental Protection (DEP) for modeling at the Turkey Point plant that was received after FPL filed its projections.

12. St. Lucie Cooling Water System Inspection & Maintenance – O&M (Project 34)

Project expenditures were $3,152,666, or 39.0% lower than expected primarily due to extensive weather condition delays. The project is scheduled to continue in 2008.

13. Clean Air Interstate Rule (CAIR) Compliance – Capital (Project 31)

Project depreciation and return on investment were $143,538, or 9.3% lower than anticipated. This under-run is associated with the re-forecasting of engineering activities associated with the installation of Selective Catalytic Reduction Systems (SCRs) and Flue Gas Desulfurization Scrubbers (FGDs) at Plant Scherer Unit 4 with scheduled in service dates of 2012.

14. Clean Air Mercury Rule (CAMR) Compliance – Capital (Project 33)

Project depreciation and return on investment were $128,903, or 37.9% lower than anticipated. This under-run is associated with the re-forecasting of engineering and procurement activities associated with the installation of the baghouse on Scherer 4 scheduled for completion in 2010.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 080007-EI

August 4, 2008

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as Senior Manager of Purchased Power in the Resource Assessment and Planning Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present for Commission review and approval the Estimated/Actual True-up associated with FPL Environmental Compliance activities for the period January 2008 through December 2008.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. My exhibit KMD-2 consists of eight forms, PSC Forms 42-1E through 42-8E, included in Appendix I. Form 42-1E provides a summary of the Estimated/Actual True-up amount for the period January 2008 through December 2008. Forms 42-2E and 42-3E reflect the calculation of the Estimated/Actual True-up amount for the period. Forms 42-4E and 42-6E reflect the Estimated/Actual O&M and Capital cost variances as compared to original projections for the period. Forms 42-5E and 42-7E reflect jurisdictional recoverable O&M and Capital project costs for the period. Form 42-8E (pages 1 through 53) reflects return on capital investments, depreciation, and taxes by project.

Q. Please explain the calculation of the ECRC Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Forms 42-2E and 42-3E show the calculation of the ECRC Estimated/Actual True-up amount. The calculation for the Estimated/Actual True-up amount for the period January 2008 through December 2008 is an under-recovery, including interest, of $5,728,576 (Appendix I, Page 4, line 5 plus line 6). This Estimated/Actual True-up under-recovery of $5,728,576 consists of January through June 2008 actuals and revised estimates for July through December 2008, compared to original projections for the same period.

Q. Are all costs listed in Forms 42-1E through 42-8E attributable to Environmental Compliance projects previously approved by the Commission?

A. Yes, with the exception of FPL's three Next Generation Solar Energy Projects, which are discussed and supported in the testimony of Eric Silagy.

Q. Have you included the 2008 costs associated with FPL's Next Generation Solar Energy Projects in the calculation of FPL's 2008 Estimated/Actual True-Up amount?

A. Yes. As described in the testimony of Eric Silagy, we have included the costs associated with FPL's three Solar Projects in the calculation of the 2008 Estimated/Actual True-Up amount. Specifically, these costs are included in KMD-2 and detailed on the following capital schedules:

- Solar – DeSoto (Project No. 37), Form 42-8E, pages 43-44 of 53.
- Solar – Space Coast (Project No. 38), Form 42-8E, pages 45-46 of 53.
- Solar – Martin (Project No. 39), Form 42-8E, pages 47-48 of 53.

FPL has included the 2008 return on construction work in progress related to these projects in the calculation of the 2008 Estimated/Actual True-Up amount.

Q. How do the Estimated/Actual project expenditures for January 2008 through December 2008 period compare with original projections?

A. Form 42-4E (Appendix I, Page 7) shows that total O&M project costs were $4,049,318 (32.8%) higher than projected and Form 42-6E (Appendix I, Page 10) shows that total capital investment project costs were $801,650 (2.4%) lower than projected. Below are variance explanations for those O&M Projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided as Form 42-8E (Appendix I, Pages 13 through 65).

O&M Project Variances

1. Air Operating Permit Fees (Project No. 1) - O&M

Project expenditures are estimated to be $324,282 (16.5%) lower than originally projected. This variance is primarily due to higher usage of natural gas as a fuel across the FPL fleet due to the higher costs of residual oil. Permit fees are based on emissions, which are proportionate to the type of fuel used at each Florida facility. Utilizing natural gas in lieu of residual oil significantly reduces SO2, Particulate Matter (PM) and NOx emissions.

2. Continuous Emissions Monitoring Systems (Project No. 3a) - O&M

Project expenditures are estimated to be $205,903 (27.4%) higher than originally projected. The increased estimate was due largely to the additional cost of the CEMS software upgrade. This upgrade was needed to meet the EPA's mandate of reporting in XML format starting 1/1/2009. Additionally the higher cost of replacement parts for the new model analyzers installed at the end of 2007 and in the first half of 2008 is reflected.

3. Maintenance of Stationary Above Ground Fuel Storage Tanks (Project No. 5a) - O&M

Project expenditures are estimated to be $836,100 (123.5%) higher than originally projected. The following project activities were identified after the filing of the original estimates for 2008:

1) Turkey Point Unit 1 Metering Tank Roof Replacement and Bottom Plate Projection Repairs project. The cross-tie valve between the two units' metering tanks was not functional and replacement and repairs took longer than expected to complete.

2) External coating of Port Everglades Terminal above grade piping. The scope of this activity was increased due to additional piping and the move from epoxy coating to silicon coating which has a longer life.

3) Performing API 570 inspections on bulk light oil piping at Ft. Lauderdale and Port Everglades power plants.

4) Martin Plant Units 1 &2 Metering Tanks painting.

5) Port Everglades Terminal Tank 805 API out-of- service inspection.

6) Painting of Fort Myers Plant Units 1&2 Tanks. The initial plan was to paint entire roof of tank No.1 and touchup the roof of Tank No. 2. The entire roofs of both tanks were painted.

7) Fort Myers Plant Tank No. 2 visual and settlement survey. Due to a leak discovered on one of the leak detection ports, a visual and settlement survey was implemented on the tank.

4. RCRA Corrective Action (Project No. 13) - O&M

Project expenditures are estimated to be $57,022 (46.7%) lower than originally projected. Estimates were included in 2008 for further action that might be required by FDEP at Turkey Point or Manatee Plant after 2007. However, FPL completed all work associated with RCRA at the Manatee and Turkey Point Fossil sites in 2007. The FDEP has granted final "No Further Action" for the Manatee Plant. The FDEP is finalizing the draft report approved by FPL for the Turkey Point Plant. This draft report recommended No Further Action for the site.

5. NPDES Permit Fees (Project No. 14) - O&M

Project expenditures are estimated to be $30,505 (19.7%) lower than originally projected. This reflects inadvertently budgeting the permit renewal application fees as ECRC expenditures. Permit renewal application fees are not classified as ECRC recoverable and thus have been removed from the ECRC true-up calculation.

6. Disposal of Noncontainerized Liquid Waste (Project No. 17a) - O&M

Project expenditures are estimated to be $32,803 (11.0%) higher than originally projected. The variance is primarily due to greater than anticipated ash accumulation in the storage basins at the Turkey Point site. As a result of the increase in ash material to be handled for removal, the site incurred extra expenses due to the use of additional moving equipment to support the job. Also, the time associated with the contractor completing the job contributed to the increases in manpower hours.

7. Substation Pollutant Discharge Prevention & Removal – Distribution (Project No. 19a) - O&M

Project expenditures are estimated to be $665,806 (68.8%) higher than originally projected. Three vendors are being used to conduct equipment leak repairs, as opposed to the previous use of only one vendor; therefore, significantly more repairs are expected to be completed this year.

8. St. Lucie Turtle Net (Project No. 21) – O&M

Project expenditures are estimated to be $0, compared to a projection of $10,000. The original estimate was related to the cost to re-coat the net once removed. When the net was being removed, a significant amount of sea grass was found to be tangled in the net which needed to be removed and required the net to be cut. The cost to repair the net as well as re-

coat it is greater than the cost to purchase a new net; therefore a new net will be purchased. The cost of the new net is considered a capital expenditure, whereas the re-coating would have been an O&M expense.

9. Pipeline Integrity Management – Distribution (Project No. 22) - O&M

Project expenditures are estimated to be $154,465 (59.4%) higher than originally projected. The following additional project activities were identified after the original 2008 projections were filed:

1) An area with insufficient cover was identified along the Martin Terminal 30" pipeline with the length of 270 feet, which needs to be addressed to stay in compliance with DOT regulations.

2) One dig was performed on January 31, 2008 on the Martin Terminal 30" pipeline and another dig is scheduled for later this year after the peak season.

3) Corroded pipe-shoes on the Martin Terminal 30" above grade DOT piping were replaced. Thirty pipe-shoes were ordered to install, saddle and replace bad pipe-shoes.

4) The 2" supply and return lines to the Martin Terminal boilers were corroded badly and multiple holes were identified. Since the boilers are running with mineral oil and not with bunker C, a decision was made to remove the lines instead of replacing / repairing them.

10. Spill Prevention, Control, and Countermeasures - SPCC

(Project No. 23) - O&M

Project expenditures are estimated to be $367,325 (94.9%) higher than originally projected, primarily due to expenditures for additional required facility upgrades that were identified during development of the SPCC plans. The additional upgrades include nitrogen blanketing systems for corrosion protection of double wall piping at Cape Canaveral, Putnam and Lauderdale Plants. These upgrades were not anticipated at the time FPL filed its original projections for 2008. In addition, work for new secondary containment for a transformer at Port Everglades was switched from Capital to O&M.

11. Port Everglades Electrostatic Precipitator – ESP (Project No. 25) - O&M

Project expenditures are estimated to be $360,685 (15.3%) lower than originally projected. Fuel economics to date have dictated that the units at the Port Everglades Plant be run on gas due to fuel oil's rising costs. Consequently, fuel oil chemical additives usage has decreased and the ESPs have not had to be operated as much as was originally projected for 2008, which reduced the equipment deterioration and generated significantly less ash for disposal.

12. Lowest Quality Water Source - LQWS (Project No. 27) – O&M

Project expenditures are estimated to be $54,797 (18.2%) lower than projected. Unplanned maintenance and repairs were performed, which

required having the system out of service.

13. CWA 316(b) Phase II Rule (Project No. 28) – O&M

Project expenditures are estimated to be $1,048,591 (73.1%) lower than projected. This variance is primarily due to economies of scale achieved through developing the database and report formats for one plant and using them across all plants. Additional economies of scale were achieved by combining meetings. The remanding of the 316(b) Phase II Rule by the Second Circuit Court also resulted in the development of more streamlined reports and significantly reduced the meeting requirements projected in 2008. Finally, per Order No. PSC-04-0987-PAA-EI issued on October 11, 2004, $129,000 of 2007 expenses were credited to the 316(b) project for the netting of environmentally-related study costs assumed to be in base rates. This amount could not be determined until actual expenses for 2007 were available in early 2008.

14. Selective Catalytic Reduction (SCR) Consumables (Project No. 29) – O&M

Project expenditures are estimated to be $493,270 (57.7%) lower than projected. Estimates related to ammonia consumption by the SCRs at SJRPP related to CAIR compliance were inadvertently included in the original estimates for this project.

15. Hydrobiological Monitoring Plan (HBMP) (Project No. 30) –

O&M

Project expenditures are estimated to be $20,401 (50.5%) lower than projected. The variance is primarily due to lower than projected costs for monitoring and reporting requirements.

16. CAIR Compliance Project (Project No. 31) – O&M

Project expenditures are estimated to be $552,892 (30.8%) lower than projected. Installation of the Boiler and Main Steam Drains at the Martin and Manatee Plants associated with the 800 MW Unit Cycling Project was listed as an O&M expense in the original projections and was subsequently re-classified as a Capital expenditure.

17. Best Available Retrofit Technology (BART) Project (Project No. 32) – O&M

Project expenditures are estimated to be $1,355, whereas FPL did not anticipate any 2008 expenditures for this project originally. During negotiations with the Florida DEP regarding FPL's proposed compliance plan for BART at the Turkey Point Fossil plant in the first quarter of 2008, the Department requested additional information and analyses. To provide the requested information FPL needed to engage an air modeling consultant to analyze the visibility improvements related to FPL's plan.

18. St. Lucie Cooling Water System Inspection & Maintenance Project (Project No. 33) – O&M

Project expenditures are estimated to be $4,554,865, or 1030.5% higher than originally projected. This variance is primarily due to weather delays, whereby some scope of work has been carried over into 2008 instead of substantially completed in 2007 as originally projected. In addition, the level of effort required to remove concrete debris was greater than anticipated.

19. Martin Plant Drinking Water System Inspection & Maintenance Project (Project No. 35) – O&M

Project expenditures are estimated to be $17,000 or 100.0% lower than projected. The Florida DEP requested a meeting to discuss the proposed design and implementation plan, which has delayed the work schedule. Preliminary approval was given based on the proposed concept of treatment. Construction applications and fees have been submitted to the FDEP. Permit issuance is expected in July 2008.

20. Low Level Radioactive Waste Project (Project No. 36) – O&M

Project expenditures are estimated to be $120,271, whereas FPL did not anticipate any 2008 expenditures for this project originally. The original estimate assumed all costs were capital. The $120,271 represents estimated costs for compressing waste to smaller volume.

Capital Project Variances

21. SO2 Allowances – Negative Return on Investment – Capital

The variance of $74,235, or 36.2% higher than projected is due to higher than anticipated gains on sales of emission allowances. The higher balance in the "Other Regulatory Liability" produces a higher return on investment.

22. Pipeline Integrity Management (Project No. 22) - Capital

The variance in depreciation and return is estimated to be $14,717, or 100% lower than projected. The installation of leak detection devices at the Martin 30" pipeline has been postponed. Further analysis is being conducted on other technology options.

23. Clean Air Interstate Rule (CAIR) Compliance (Project No. 31) - Capital

The variance in the return on CWIP is estimated to be $2,200,113 or 37.3% higher than projected. The variance is primarily due to higher than projected material costs for structural steel and higher than projected labor costs for the SCR installation on Units 1 and 2 at SJRPP.

24. Clean Air Mercury Rule (CAMR) Compliance (Project No. 33) - Capital

The variance in the return on CWIP is estimated to be $2,524,933 or 61.7% lower than projected. The variance is primarily a result of changes in project schedule for the baghouse and sorbent injection installation on Scherer Unit 4, which delayed equipment procurement and certain

construction activities to future years.

25. Martin Plant Drinking Water System Inspection & Maintenance Project (Project No. 35) - Capital

The variance in depreciation and return is $4,574 or 31.5% lower than projected. The Florida DEP requested a meeting to discuss the proposed design and implementation plan, which has delayed the work schedule. Preliminary approval was given based on the proposed concept of treatment. Construction applications and fees have been submitted to the FDEP. Permit issuance is expected in July 2008.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 080007-EI

AUGUST 29, 2008

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as Senior Manager of Purchased Power in the Resource Assessment and Planning Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present for Commission review FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2009 through December 2009 period.

Q. Is this filing by FPL in compliance with Order No. PSC-93-1580-FOF-EI, issued in Docket No. 930661-EI?

A. Yes. The costs being submitted for the projected period are consistent with that order.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes. KMD-3 consists of seven documents, PSC Forms 42-1P through 42-7P provided in Appendix I. Form 42-1P summarizes the costs being presented at this time. Form 42-2P reflects the total jurisdictional costs for O&M activities. Form 42-3P reflects the total jurisdictional costs for capital investment projects. Form 42-4P consists of the calculation of depreciation expense and return on capital investment for each project. Form 42-5P gives the description and progress of environmental compliance activities and projects for the projected period. Form 42-6P reflects the calculation of the energy and demand allocation percentages by rate class. Form 42-7P reflects the calculation of the ECRC factors.

Q. Please describe Form 42-1P.

A. Form 42-1P (Appendix I, Page 2) provides a summary of projected environmental costs being presented for the period January 2009 through December 2009. Total environmental costs, adjusted for revenue taxes, amount to $93,698,955 (Appendix I, Page 2, Line 5) and include $91,077,343 of environmental project costs (Appendix I, Page 2, Line 1c) increased by the revised estimated/actual true-up under-recovery of $5,728,576 for the January 2008 - December 2008 period (Appendix I,

Page 2, Line 2), and decreased by the final true-up over-recovery of $3,174,379 for the January 2007 – December 2007 period (Appendix I, Page 2, Line 3).

Q. Please describe Forms 42-2P and 42-3P.

A. Form 42-2P (Appendix I, Pages 3 and 4) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. Form 42-3P (Appendix I, Pages 5 and 6) presents the environmental project capital investment costs for the projected period. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand.

The method of classifying costs presented in Forms 42-2P and 42-3P is consistent with Order No. PSC-94-0393-FOF-EI for all projects.

Q. Please describe Form 42-4P.

A. Form 42-4P (Appendix I, Pages 7 through 60) presents the calculation of depreciation expense and return on capital investment for each project for the projected period.

Q. Please describe Form 42-5P.

A. Form 42-5P (Appendix I, Pages 61 through 107) provides the description and progress of environmental projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 108) calculates the allocation factors for

demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please describe Form 42-7P.

A. Form 42-7P (Appendix I, Page 109) presents the calculation of the proposed ECRC factors by rate class.

Q. Are all costs listed in Forms 42-1P through 42-7P attributable to Environmental Compliance projects previously approved by the Commission?

A. Yes, with the exception of the Electric Utility Greenhouse Gas Reduction Program, which is discussed and supported in the testimony of Randall R. LaBauve.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 080007-EI

August 4, 2008

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Environmental Services.

Q. Have you previously testified in predecessors to this docket?

A. Yes, I have.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an update on FPL's approved Clean Air Interstate Rule (CAIR) Compliance, Clean Air Mercury Rule (CAMR) Compliance and BART (CAVR) Projects, and to discuss the impact of the Court's decision to vacate CAIR on these projects. I also describe an additional activity that will be required under FPL's approved St. Lucie Cooling Water System Inspection and Maintenance Project.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibit RRL-1, which contains FPL's Supplemental

CAIR/CAMR/CAVR Filing, filed with the Commission on April 2, 2008. Exhibit RRL-1 is included in Appendix II.

Q. Please provide a brief summary of the Court's decision to vacate CAIR.

A. Various legal challenges to CAIR, including FPL's, were presented in oral argument before the DC Circuit Court of Appeals on March 25, 2008. On July 11, 2008 the Court issued a *per curiam opinion* vacating CAIR in its entirety and remanding it to the Environmental Protection Agency (EPA) to promulgate a rule that is consistent with the court's opinion. Parties to the appeal may seek rehearing before the same three-justice panel or rehearing *en banc* by filing a petition with the Court within 45 days – August 25, 2008. Parties may also petition the US Supreme Court for a writ of certiorari within 90 days after the opinion was issued or within 90 days after the Court resolves any petition(s) for rehearing. This deadline would be October 9, 2008 if no one seeks rehearing.

The Court's opinion agreed with some of FPL's challenges to CAIR, including EPA's inappropriate use of fuel factors for the allocation of NOx allowances. However, the Court rejected the arguments advanced by FPL and the Florida Association of Electric Utilities that all or part of Florida should have been excluded from the CAIR region, deferring to EPA's technical expertise.

If the Court's decision becomes final, the Florida Department of

Environmental Protection (DEP) will be obligated to initiate rulemaking to remove those sections of its rules that adopted the CAIR program. Affected sources within Florida would return to the existing Acid Rain SO2 allowance program and would no longer be subject to annual or Ozone Season NOx allowance programs.

Q. What is the current status of FPL's CAIR Compliance Project?

A. FPL's CAIR Compliance Project currently consists of the installation of Selective Catalytic Reduction (SCR) controls and Flue Gas Desulfurization (FGD) on Plant Scherer Unit 4, SCR controls on St. John's River Power Park (SJRPP) Units 1 and 2, the 800 MW Cycling Project for the Manatee and Martin 800 MW units, and the installation of Continuous Emission Monitor Systems (CEMS) at FPL's Gas Turbine Peaking Units.

Scherer SCR and FGD - Construction has begun on the common plant components for the Scherer CAIR Projects. Current total capital cost estimates for FPL's ownership share of the installation of Wet FGD Scrubber and SCRs with Ammonia Injection System on Scherer Unit 4 remains at $392.6 million (76.36% ownership of Unit 4). Georgia Power Company has provided preliminary O&M estimates for the SCR and FGD operation with an annual total fixed and variable O&M of $4.5 million for FPL's share beginning in 2012. O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment. O&M activities for the FGD include limestone consumption, limestone and by-product

handling operation, FGD operations, FGD tower and auxiliary equipment maintenance. Completion of the Scherer Unit 4 controls is scheduled for first quarter of 2012.

SJRPP SCR and Ammonia Injection Systems - The SCR CAIR Project at SJRPP is approximately 80 % complete and is scheduled to be completed in the first quarter of 2009. FPL's share of the projected total cost for installation of SCRs and Ammonia Injection Systems on SJRPP Units 1 and 2 remains $45.5 million. Estimated annual O&M expenses beginning 2012 are $1.2 million (FPL 20% ownership).

800 MW Unit Cycling Project - The Martin and Manatee projects are underway and are scheduled to be complete with the last unit, Martin Unit 2, in December of 2010. FPL plans to complete the project work at the Manatee and Martin plants in 2010 with an estimated total project cost of $104.8 million in Capital costs and $5.3 million in O&M expenses.

CEMS Plan for GTs - The peaking GT CEMS installations are planned to be completed in 2008.

Q. How does FPL plan to address the vacature of CAIR as it relates to its CAIR Compliance Project?

A. In view of the tight deadlines under CAIR, FPL believes that it is prudent and necessary to continue towards completion of its CAIR Compliance Project unless and until the DC Circuit's opinion vacating CAIR becomes

final.

If and when the DC Circuit opinion becomes final, FPL will re-evaluate the impact of the vacature on its air emission control obligations taking into account the various other environmental compliance requirements to which FPL's generating facilities are subject as well as available information on EPA's plans to respond to the Court's direction that it initiate new rulemaking consistent with the opinion. In the short run, vacature would have a clear-cut impact on compliance costs, because FPL would not be required to purchase NOx allowances for compliance with CAIR. However, FPL would not be relieved of its obligation to comply with environmental compliance requirements other than CAIR, and those other requirements could dictate the installation and operation of the same emissions controls that FPL would use to comply with CAIR.

For example, the controls being installed on Scherer Unit 4 to comply with CAIR are also mandated under the Georgia Multi-Pollutant Rule. Thus, installation of the FGD and SCR controls at Plant Scherer will remain cost effective and must be completed to allow FPL to continue operation of Unit 4, regardless of CAIR's fate. Similarly, the installation of the SCR at SJRPP Units 1 and 2 has been completed on one unit with significant work having been completed on the remaining unit. FPL has reviewed the status of the revised 8-Hour Ozone National Ambient Air Quality Standard for Duval County and believes that reductions in NOx emissions being

provided by the installation of SCR on the SJRPP units are likely to be required under a State Implementation Plan addressing the county attainment status. FPL has also reviewed the 800 MW Cycling Project and has determined that, if the CAIR vacature becomes final, the substantial reduction in NOx emissions at these plants would still be useful for addressing local ozone non-attainment issues that are likely to arise under the revised Ozone Standard. By allowing FPL to cycle less efficient units off-line when they are not needed, the project would also provide substantial fuel savings to our customers that exceed the project's revenue requirements.

Q. What is the current status of FPL's CAMR Compliance Project?

A. FPL's CAMR Compliance Project includes the installation of Baghouse and Sorbent Injection system with Mercury CEMS on Plant Scherer Unit 4, and the installation of Mercury CEMS at Units 1 and 2 of SJRPP. Installation of the Scherer Mercury controls has begun and is scheduled to be in-service January 2010. FPL's projected capital cost for its share of the Mercury control and CEMS installation at Plant Scherer remains at $99.6 Million. The installation of the Mercury CEMS at SJRPP Units 1 and 2 has been completed.

As discussed in FPL's April 2, 2008 Supplemental CAIR/CAMR/CAVR filing (my Exhibit RRL-1), on February 8, 2008 the US District Court of Appeals ruled that EPA's Delisting rule for Mercury emissions from coal-fired Electric Generating Units (EGUs) utility boilers and the Clean Air

Mercury Rule were unlawful, and the Court vacated both rules. EPA did not seek further review of the Court's decision, and is now required by the Clean Air Act to promulgate a new rule for reduction of Mercury emissions consistent with the decision of the Court.

With the Court's vacature of the Delisting rule, EPA is now likely to proceed with evaluation and implementation of the existing rule requiring Maximum Available Control Technology (MACT) for Mercury emissions from coal-fired EGUs. Prior to the implementation of the Delisting and CAMR rules the MACT analyses had determined that the use of Sorbant Injection systems were effective in the removal of Mercury and established the CAMR Phase I and II Mercury budgets based on the implementation of the technology on coal-fired EGUs by 2018. The Georgia Multi-Pollutant Rule requires that each of the four units at Plant Scherer implement a Sorbant Injection system with a baghouse collection device for removal of Mercury. Therefore, installation of the Mercury controls that would have been needed to comply with the CAMR requirements remains necessary to comply with the requirements of the Georgia Multi-Pollutant Rule, so the vacature of CAMR does not change the compliance obligations at Plant Scherer, including FPL's share of Unit 4. Installation of the Mercury Continuous Emissions Monitoring System (HgCEMS) that was planned to comply with CAMR likewise will be needed to comply with the monitoring and reporting requirements of the Multi-Pollutant Rule and ultimately to demonstrate compliance with

monitoring of the final MACT rule.

For the SJRPP units FPL, and majority owner JEA, had planned to comply with Phase I of the CAMR through the co-benefits removal of Mercury by the SCR and Scrubber for units burning bituminous coals. The planned addition of the SCR on both SJRPP units to comply with CAIR would achieve the co-benefit reductions as both units were constructed with Scrubbers installed. As I discussed earlier in my testimony, CAIR has recently been vacated as well, although that decision is still open to review on rehearing and/or by petition for certiorari to the U.S. Supreme Court. In any event, FPL believes that the reductions in NOx emissions resulting from the installation of SCR on the SJRPP units is likely to be required under a State Implementation Plan addressing attainment of the revised 8-Hour Ozone National Ambient Air Quality Standard for Duval County.

The Supplemental CAIR/CAMR/CAVR filing indicated that FPL intends to revise its CAMR Compliance Project to reflect the different environmental compliance requirements that now dictate the emission controls that are being undertaken pursuant to the Project. This remains FPL's intent, but due to the current flux in the status of CAIR as well as the relevant state-level environmental compliance requirements, FPL has concluded that it would be more productive to defer its revision filing until there is greater clarity on those issues. FPL presently expects to file for revision of the

CAMR Compliance Project by the end of 2008.

Q. What is the current status of FPL's Clean Air Visibility Rule (CAVR) / Best Available Retrofit Technology (BART) Project?

A. Following the vacature of CAIR, the Florida DEP has begun evaluating the impacts on implementation of CAVR/BART within Florida. However, FPL does not yet have enough information on to assess how the Florida DEP's changes to its CAVR/BART requirements will affect FPL's compliance obligations under this project.

St. Lucie Cooling Water System Inspection and Maintenance Project Update

Q. Please briefly describe FPL's currently approved St. Lucie Cooling Water System Inspection and Maintenance Project.

A. The purpose of the St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system at FPL's St. Lucie nuclear plant (the "Cooling System") such that it minimizes injuries and/or deaths of endangered species as required for FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") Compliance with the ESA is a condition to the operation of the St. Lucie Plant. In accordance with ESA Section 7 requirements, consultations and resulting Biological Opinion currently in draft and expected by the end of August 2008, corrective actions have been

identified that minimize injuries to protected species. These corrective actions are based on trends in sea turtles injuries, and detailed inspections of the Cooling System.

Q. What activities have been undertaken related to the Project?

A. Because of an upward trend in sea turtle injuries exceeding FPL's allowable "take" of sea turtles in 2006, during April/May of 2007 the St. Lucie Plant completed preparations and inspections of the two 12 ft and one 16 ft diameter ocean intake pipes to identify potential causes of sea turtle injuries. Based on these inspections, cleaning of the pipes was started in October of 2007 to remove concrete debris and Marine growth contributing to turtle injuries. The installation of devices to block off a dead end section of the piping was completed in November of 2007. Because of weather delays some of the scope of work is now being performed in 2008.

Q. What activities related to the Project are currently in progress?

A. The following activities are currently in progress:

- Cleaning of intake pipes to remove protruding structural impediment or biofouling and debris accumulation that extends into the flow path.
- Submittal of monthly reports of causal injuries. Biological Opinion to require implementation of corrective actions as required based on increasing turtle injuries documented by monthly reports.
- Removal of vegetation on the canal banks so that turtle crawls would be more visible.

- Flow sensors to facilitate accurate calculation of flow rates for extended windows for cleaning of the pipes and identification of potential buildup of debris that may cause blockage of the pipes and injury to marine life.

Q. Has FPL identified additional work that it must undertake pursuant to the Project?

A. Yes. In my affidavit filed with the Commission on January 8, 2007 in support of FPL's request to recover costs through the ECRC associated with the Project, I stated that additional work may have to be performed on the Cooling System in the future in order to satisfy "take" limitations imposed under the ESA and/or to address plant operational impacts resulting from work done to satisfy those limitations.

As part of the Section 7 Consultations, and resulting Biological Opinion (which is currently in draft and is expected in final form by the end of August 2008), FPL will be required to install exclusion devices at the velocity caps to prevent large marine organisms, such as adult sea turtles and smalltooth sawfish, from entering the intake pipes. The exclusion devices consist of a support structure installed in the opening of the velocity caps, which will support panels containing a mesh with a 20" opening installed at approximately 45 degrees. The structure design minimizes the potential of trapping marine life yet has only a negligible impact on the cooling water flow into the velocity cap. A conceptual design has been submitted to the NRC for review.

Q. When does FPL expect to incur costs for the exclusion devices required for the Project?

A. FPL currently expects to begin incurring costs associated with design and project planning in the last quarter of 2008, with installation costs incurred in 2009.

Q. What is FPL's estimated cost for the design, project planning and installation of the exclusion devices?

A. FPL currently estimates that the total cost for the exclusion devices will be approximately $3.75 million.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 080007-EI

AUGUST 29, 2008

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Environmental Services.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present for Commission review and approval a new environmental project - the Greenhouse Gas (GHG) Reduction Program. Additionally, my testimony discusses the current status of FPL's approved CAIR/CAMR/CAVR projects resulting in light of the vacatur of the United States Environmental Protection Agency's (EPA's) CAIR and CAMR rules.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control, any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibit RRL-2 – Executive Order 07-127 and Exhibit RRL-3 – HB 7135: The Florida Climate Protection Act.

GHG REDUCTION PROGRAM

Q. Please describe the law or regulation requiring the Greenhouse Gas Reduction Program.

A. On July 13, 2007 Florida Governor Charlie Crist signed Executive Order 07-127 establishing immediate actions to reduce GHG emissions within Florida. The Governor's order requires the Florida Department of Environmental Protection (FDEP) to establish maximum allowable GHG emissions for electric utilities within the state. HB 7135 provides for a regulatory and legislative process to implement the Governor's Executive Order 07-127. The FDEP has begun rulemaking under Chapter 403 of the Florida Statutes, as amended by HB 7135, to implement the reductions in GHG emissions from electric utilities needed to achieve those GHG limits. EPA has also received appropriations to begin rulemaking for the mandatory reporting of GHG emissions from sources. A proposed rule is anticipated from EPA by September of 2008 with a final rule promulgated by June of 2009.

Q. Does HB 7135 have any other impacts on FPL?

A. Yes. HB 7135 requires major emitters, including electric utilities, to report GHG emissions to the nonprofit partnership "The Climate Registry"

providing historical and current GHG emission data to establish the baseline emissions and targets for the required compliance reductions to meet the 2017, 2025 and 2050 goals established in Executive Order 07-127. Reporting GHG emissions to the registry requires an annual membership fee, use of specific reporting protocols for the calculation and reporting of GHG emissions in an electronic reporting system, and third party verification of reported emissions to provide accreditation for the reporting entity's emissions.

As I mentioned earlier, HB 7135 also requires that FDEP initiate rulemaking to establish a Florida GHG cap-and-trade program no earlier than January 1, 2010 and submit the rule to the legislature for ratification. Details of that program have not yet been established and it is unknown at this time whether allowances will be allocated to sources in whole or in part, or will be available only at auction. Regardless of whether the allowances are allocated or auctioned, however, the need for CO2 allowances will become part of the fossil generation costs. FPL has included CO2 emission allowance market price projections in its evaluation of proposed generation expansion projects including its proposed Nuclear Uprate projects, Turkey Point Nuclear Unit 6 & 7 expansion, West County Energy Center Unit 3 and the proposed Conversion Projects at Riviera and Cape Canaveral Plants. Future CO2 allowance and program management costs would be included in FPL's Greenhouse Gas Reduction Program.

Q. Please describe the activities FPL will initiate as a result of this project.

A. FPL plans to comply with Florida reporting requirements for its GHG emissions through participation in The Climate Registry reporting program. FPL will begin GHG reporting activities in 2009 during its initial implementation of the FPL Greenhouse Gas Reduction Program. FPL is proposing to recover the costs associated with joining the registry, the preparation of the initial GHG report, and the electronic data reporting required by the registry.

Q. What are the compliance dates for this project?

A. The FDEP has indicated that it will complete its rulemaking by June of 2009 requiring mandatory GHG reporting to The Climate Registry by all electric utilities within the state. FPL anticipates that FDEP will complete additional rulemaking to adopt a GHG cap-and-trade program within Florida by January 2010 to address those requirements of HB 7135 for the electric utility sector.

Q. Has FPL estimated the cost of its Greenhouse Gas Reduction Program?

A. The ultimate cost of the Project will depend on the rules developed by the FDEP to implement Executive Order 07-127 and HB 7135. To comply with the reporting requirements FPL will initiate required activities in 2009 to join The Climate Registry and report baseline data. Subsequent to the data reporting in 2009, FPL is required to engage the services of a Registry-approved Third Party Verification consultant. Costs for

verification of reported GHG emissions are dependant on the protocol used in reporting data and the complexity of the GHG emissions reported. FPL has not included a projection of these costs at this time and anticipates verification to occur in 2010. FPL will provide estimates of these costs once the appropriate reporting protocol has been identified for FPL.

FPL's nuclear, renewable and conversion generation projects along with our energy efficiency program will further reduce greenhouse GHG, which will help to achieve compliance with the Cap and Trade rule being developed by FDEP. To achieve the future reduction goals established by Executive Order 07-127, which will be included in FDEP's Cap and Trade rule, FPL anticipates that additional reductions in its GHG emissions will be required beyond the currently planned projects. The additional reductions will likely require a combination of the implementation of carbon sequestration and storage technology, further implementation of cost-effective zero and low GHG emitting renewable generation, expansion of Demand Side Management (DSM) and Energy Efficiency (EE) programs, and the use of verified carbon offset projects. Costs associated with the implementation of controls and storage technologies for GHG emission reductions, and prudently incurred costs for required offsets for mitigation of GHG emissions to comply with regulations would also be included in FPL's Greenhouse Gas Reduction Program. Costs associated with the expansion of DSM and EE programs would not be

recovered as an FPL ECRC project, although FPL likely will seek recovery of those costs through the Energy Conservation Cost Recovery (ECCR) Clause.

FPL believes that it is premature to identify specific reduction strategies beyond the Non-GHG emitting and Low-GHG emitting generation expansion projects needed to meet future capacity needs that will provide substantial reductions in FPL System GHG emissions. GHG emission controls for fossil fuel fired Electric Generating Units (EGUs) are not yet commercially available nor have they yet been demonstrated as cost-effective technology. Similarly Carbon Capture and Storage is still under development and has not yet been demonstrated as commercially available for fossil fuel-fired EGUs nor has risks associated with the transportation and storage of CO2 been mitigated. FPL does anticipate that further advances in these technologies are likely to occur over the coming years prior to the 2025 and 2050 deadlines established in the Governor's order.

Q. Has FPL estimated how much will be spent on the Project in 2009?

A. Yes, FPL expects to begin incurring such costs following publication of registry guidance and rulemaking by the FDEP, which is anticipated to occur prior to the June 2009 date for the final federal mandatory GHG emissions reporting rule. FPL's preliminary estimate of $50,000 in 2009 O&M expenses for the project includes the projected registration and consultant fees for the first year of Climate Registry participation.

Specifically, FPL anticipates the following required activities in 2009 for The Climate Registry:

1. Annual Membership Fee for joining The Climate Registry: $15,000 (annual fee is $10,000 and includes additional one-time fee of $5,000 for reporting prior year baseline emissions)
2. Preparation of GHG Baseline Emission Inventory for FPL: $20,000 (includes contractor labor costs for identification of emission source data, selection and application of registry approved methods, and quantification of baseline GHG emission data)
3. Preparation, formatting, and data entry of FPL emissions data for submittal to the Climate Registry Information System (CRIS): $15,000 (includes contractor labor costs associated with data entry for: a) creation of corporate/entity profile inputs; b) creation of facility accounts with location specific information; c) populating entities with baseline GHG emission inventory data into on-line reporting system).

Q. How will FPL ensure that the costs incurred are prudent and reasonable?

A. Consistent with our standard practice for all contractor services procurements, FPL will competitively bid the contractor selection for the GHG reporting activities. FPL has a working knowledge of the appropriate costs that should be incurred for this task. We will ensure that the contractor utilizes practices adopted by The Climate Registry for completing the inventory and reporting activities of the project and

provides a reasonable cost estimate before initiating the project.

Q. **Is FPL recovering through any other mechanism the costs for the Greenhouse Gas Reduction Program for which it is seeking ECRC recovery?**

A. No.

CAIR/CAMR/CAVR STATUS UPDATE

Q. **What is the current status of CAIR?**

A. The CAIR vacatur is not yet final. EPA has received a 30 day extension of the deadline for seeking rehearing of the vacatur order before the D.C. Circuit, with the deadline now being September 24, 2008. Until rehearing is complete and there either is resolution of further appeals to the US Supreme Court or the time for such appeals has expired, there is no way of knowing whether CAIR ultimately will be vacated, or will remain in effect either in its current or modified form. Furthermore, assuming the Court's order vacating CAIR is ultimately finalized, that order directed EPA to adopt a replacement rule consistent with the Court's decision. While the Court agreed with some of the arguments FPL made in its challenge to CAIR, it rejected the argument by FPL and other Florida utilities that Florida should be excluded from the CAIR region. And the Court also criticized EPA for spreading out the CAIR emission reductions over two phases (2009/2010 and 2015), holding that EPA needed to impose the full requirements by 2010. Therefore, if CAIR is vacated, EPA will be under pressure to devise alternative emission reduction rules in a very short

time period to address the Ozone and PM2.5 National Ambient Air Quality Standards (NAAQS) impacts of upwind sources on downwind non-attainment areas. It is reasonable to expect that those rules will apply to utilities in Florida.

Q. Should FPL continue its CAIR Compliance Projects?

A. Yes. FPL believes that continuing with construction of its CAIR Compliance projects that are currently underway is clearly in the best interests of our customers. FPL has considered several factors in support of the decision to continue with the projects at this time, including the following:

1. Until the vacatur of CAIR has been finalized through court action by the D.C. Circuit and/or the Supreme Court, we must continue to comply with CAIR.
2. Should CAIR be vacated, the EPA will have to act quickly, consistent with the Court's ruling, to ensure that non-attainment areas for ozone and PM2.5 are addressed in further rulemaking by 2010.
3. States with non-attainment areas retain the ability under Section 126 of the Clean Air Act to require EPA to consider contributions from upwind sources (which had been identified in part through CAIR modeling that resulted in Florida being included in CAIR for Ozone and PM2.5 impacts).
4. The Scherer CAIR Project controls must be installed and operated in order to comply with the Georgia Multi-Pollutant Rule.
5. The SCR controls at SJRPP are nearing completion, with the SCR

construction having been completed for Unit 2 and approximately 60% complete for Unit 1. If CAIR is vacated, FPL fully expects that SCRs will be required at SJRPP in the near future in order to comply with EPA's and/or FDEP's replacement for CAIR, in response to Clean Air Act Section 126 petitions objecting to SJRPP's contribution to downwind non-attainment (its location in extreme north Florida makes it vulnerable to such petitions), or to comply with other environmental requirements. For example, while SJRPP is upwind of existing Ozone and PM2.5 designated non-attainment areas in Florida, the SJRPP Units are likely to be required to reduce emissions of NOx to address designation of Duval County as non-attainment of the 2007 revised Ozone NAAQS which was set to 75 ppb.

SJRPP has estimated significant capital costs associated with delay of construction of one year or longer through demobilization and remobilization of equipment and labor, and through materials cost increases in addition to anticipated delays in catalyst availability through forfeiture of contract. If construction of the Unit 1 SCR were delayed, by even one year, it would result in a cost increase of $7.6 million to complete construction and would impose an 18 month delay in completion of the SCR because we would lose our spot in the queue for acquiring the catalyst necessary to operate the SCR. FPL's share of the additional cost for the delay by only one year

would be in excess of $1.5 million. FPL does not believe it would be consistent with the best interests of its customers to put those SJRPP SCR project on hold with the high likelihood that the SCRs will be required in the near future even without CAIR and the substantial additional costs that would result if the project were put on hold.

6. The 800 MW Cycling project for Manatee Units 1 and 2, and Martin Units 1 and 2 ,in addition to providing annual and ozone season reductions in NOx emissions, also provide substantial fuel savings by allowing these large units to cycle off-line more frequently when not needed for system load. Projected fuel savings associated with the 800 MW Cycling Project are $2.9 billion over the life of the project.

Q. Should FPL continue to recover Capital and O&M costs associated with its CAIR Compliance Projects?

A. Yes. FPL must continue with the construction of these projects to meet CAIR requirements that remain in effect until there is a final decision, in the case of the Scherer project, in order to meet the requirements of the Georgia Multi-Pollutant rule. Moreover, as discussed above, it would not be in the economic interests of our customers to defer or discontinue either the SJRPP SCR project or the 800 MW Cycling Project FPL also plans to recover O&M costs associated with the operation of the controls required for CAIR compliance, or compliance with other requirements including the Georgia Multi-Pollutant rule. Should regulatory requirements

change and operation of the controls not be required on an annual or seasonal basis, FPL will make appropriate adjustments through the ECRC True-Up process to ensure savings are returned to customers.

I would like to point out that increases in steel costs and labor during 2008 have increased the project cost for the SJRPP SCRs from the original projection of $227 million to a revised total cost of $239 million for the total project with FPL's share of the total cost now at $47.8 million.

Q. What is the status of FPL's CAMR Compliance Project in light of the vacatur of CAMR?

A. The CAMR was vacated by the US Court of Appeals on February 8, 2008 and remanded back to the EPA for reconsideration with the court immediately issuing its mandate finalizing the fate of CAMR. I should point out that the vacatur of CAMR was coupled with rejection of EPA's delisting of coal fired EGUs from the list of emission sources that are subject to regulation under section 112 of the Clean Air Act. Therefore, EPA must begin rulemaking to define Maximum Available Control Technology (MACT) for control of mercury (Hg) emission on coal fired EGUs. In 2005, prior to CAMR, EPA had established several MACT categories for coal fired EGUs requiring specific Hg emission standards.

FPL's installation of Hg Controls on Unit 4 at Plant Scherer must continue as planned, in spite of the vacatur of CAMR, in order to comply with the Georgia Multi-Pollutant rule. FPL also believes that the Hg controls being

installed at Plant Scherer represent Maximum Available Control Technology for Hg emissions and will meet any subsequent MACT standard developed by EPA to address coal fired EGU Hg emissions. FPL and JEA intended to comply with CAMR by achieving co-benefits from the operation of the SCRs that are being installed to comply with CAIR, so there are no separate Hg controls at SJRPP that would be affected by the CAMR vacatur. CAMR did impose distinct monitoring requirements, however, and FPL has planned to comply with those monitoring requirements at SJRPP by installing Hg Continuous Emission Monitoring System (HgCEMS). The system had already been procured and was being installed prior to the vacatur of CAMR. Installation of monitors has already been completed on SJRPP Units 1 and 2. The remand of the Hg monitoring rules under CAMR temporarily removes the requirement for the HgCEMS to complete certification requirements and begin continuous operation. Until required by regulation or rule, FPL does not intend to operate the HgCEMS and has not included HgCEMS O&M in the ECRC for the CAMR Project.

Q. What is the status of FPL's BART Project as it relates to the vacatur of CAIR?

A. Should the vacatur of CAIR become final, the "BART equals CAIR" exemption adopted by the Clean Air Visibility Rule (CAVR) would also be nullified, thus requiring the FDEP to address BART at all applicable units within the state. FPL had begun negotiations with FDEP concerning Turkey Point Fossil Units 1 & 2 having made substantial progress until the

vacatur of CAIR. While FDEP was seeking guidance from EPA regarding the affect of the CAIR vacatur on BART and CAVR, until the fate of CAIR is known FPL believes that the CAIR exemption remains.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ERIC SILAGY

DOCKET NO. 080007-EI

August 4, 2008

Q. Please state your name and business address.

A. My name is Eric Silagy. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By who are you employed and what position do you hold?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Vice President and Chief Development Officer.

Q. Please describe your duties and responsibilities in that position.

A. I lead FPL's efforts to develop new electric generation, including the development of clean, zero greenhouse gas emitting renewable electric generation.

Q. Please describe your professional experience and education.

A. Prior to being appointed Chief Development Officer for FPL, I was employed by FPL Energy as Vice President/General Manager for the Texas region. In this capacity, I was responsible for managing all business activities related to FPL Energy's generation assets in the region, including 1,600 megawatts ("MW") of wind power. Prior to undertaking those duties in Texas, I served as Vice President, Business Development with responsibility for managing and

supporting FPL Energy and FPL Group merger and acquisition activities, including all nuclear power plant acquisitions.

Prior to joining FPL Energy, from 1999 to 2003, I served as Vice President, Mergers, Acquisitions & Divestitures at Entergy Wholesale Operations. In that position, I led the successful sale and purchase of numerous energy related assets and companies in the U.S. and overseas. Prior to joining Entergy, I held the position of Vice President, Development, Southeast Asia for The Wing Group, a subsidiary of Western Resources. In this capacity, I was responsible for managing power generation development activities and offices in Thailand, Indonesia, the Philippines and Singapore.

From 1987 to 1996, I served on the staff of United States Senator J. Bennett Johnston. During this time, my work included service in a variety of roles including Professional Staff member of the U.S. Senate Energy and Natural Resources Committee, Legislative Assistant and Chief of Staff. I hold a B.A. in Economics from the University of Texas at Austin and a J.D. from the Georgetown University Law Center.

PURPOSE AND SUMMARY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present for Commission review and

approval under the Environmental Cost Recovery Clause ("ECRC"), the recoverable costs for three new projects: Martin Next Generation Solar Energy Center ("Martin Solar"), DeSoto Next Generation Solar Energy Center ("DeSoto Solar") and the Space Coast Next Generation Solar Energy Center ("Space Coast Solar").

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibits ES-1 through ES-3, which are included in Appendix III.

ES-1 Martin Solar Project Milestones

ES-2 DeSoto Solar Project Milestones

ES-3 Space Coast Solar Project Milestones

Q. Would you please summarize your testimony?

A. In Docket Number 080281-EI, the Commission found at the July 15, 2008 Agenda Conference that the Martin Solar, DeSoto Solar and Space Coast Solar projects are eligible for recovery through the ECRC pursuant to House Bill 7135, hereafter referred to as the 2008 Energy Bill ("Energy Bill"). The actual and estimated 2008 costs for these three projects are reasonable in amount and have been spent appropriately. Therefore, such costs should be recovered through the ECRC.

BACKGROUND

Q. Would you please provide an overview of the recently passed 2008 Energy Bill?

A. Florida's Legislature recently passed the Energy Bill, which facilitates the development of clean, zero greenhouse gas emitting renewable generation in Florida. Governor Crist signed this legislation into law on June 25, 2008 at the 2008 Serve to Preserve Florida Summit on Global Climate Change. The law became effective July 1, 2008. Consistent with the Energy Bill's emphasis on demonstrating the feasibility and viability of clean, zero greenhouse gas emitting energy systems in Florida, FPL plans to construct and operate three separate solar energy projects totaling 110 MW with different characteristics, at diverse locations. These projects will not only generate clean, renewable energy, but will also provide significant information and experience regarding key aspects of siting, constructing and operating different solar technologies at various locations in Florida.

Q. Please describe the portions of the 2008 Energy Bill that apply to zero greenhouse gas emitting renewable generation in Florida.

A. Section 366.92, Florida Statutes, expresses the Florida Legislature's support for renewable energy. Part of the Energy Bill extends this support by amending Section 366.92 to promote development of up to 110 MW of zero greenhouse gas emitting renewable generation, by permitting full cost recovery for qualifying projects through the ECRC.

Q. Please quote the specific portion of the 2008 Energy Bill to which you are referring.

A. The Energy Bill provides in relevant part that:

> In order to demonstrate the feasibility and viability of clean energy systems, the commission shall provide for full cost recovery under the environmental cost-recovery clause of all reasonable and prudent costs incurred by a provider for renewable energy projects that are zero greenhouse gas emitting at the point of generation, up to a total of 110 megawatts statewide, and for which the provider has secured necessary land, zoning permits, and transmission rights within the state. Such costs shall be deemed reasonable and prudent for purposes of cost recovery so long as the provider has used reasonable and customary industry practices in the design, procurement, and construction of the project in a cost-effective manner appropriate to the location of the facility. The provider shall report to the commission as part of the cost-recovery proceedings the construction costs, in-service costs, operating and maintenance costs, hourly energy production of the renewable energy project and any other information deemed relevant by the commission. Any provider constructing a clean energy facility pursuant to this section shall file for cost

recovery no later than July 1, 2009.

Q. How does the 2008 Energy Bill facilitate the development of new renewable energy resources in Florida?

A. The Energy Bill promotes the development of new renewable resources in Florida by giving the Commission specific authority to approve for cost recovery new renewable energy resources that are "zero greenhouse gas emitting at the point of generation."

The Energy Bill facilitates new renewable development by investor owned electric utilities by providing for full cost recovery under the ECRC of all reasonable and prudent costs incurred for renewable energy projects that are zero greenhouse gas emitting at the point of generation, up to a total of 110 MW statewide, and for which the provider has secured necessary land, zoning permits and transmission rights within the state.

In Docket Number 080281-EI, the Commission found at the July 15, 2008 Agenda Conference that FPL's three proposed solar energy center projects are eligible for recovery through the ECRC pursuant to the Energy Bill.

FPL'S PROPOSED MARTIN NEXT GENERATION SOLAR ENERGY CENTER ("MARTIN SOLAR")

Q. Please provide an overview of FPL's proposed Martin Solar project.

A. FPL proposes to construct an approximately 75 MW solar thermal steam generating facility which will be integrated into an existing combined cycle power plant at the existing Martin Power Plant site in Martin County, Florida, thereby creating the world's first hybrid energy center. Martin Solar will be the second largest solar generating facility in the world. This generation plant will be constructed on an approximately 600-acre site (comprised of 500 acres for the solar field and 100 acres for related construction, operation and maintenance activities), which is fully contained within FPL's existing 11,300-acre Martin Plant site and will be the first of its kind to integrate solar technology with a combined cycle natural gas plant.

Q. Please describe the solar energy technology that will be used for the project.

A. The Martin Solar project will involve the installation of solar thermal technology that will be integrated into the existing steam cycle for the Martin Power Plant Unit 8 natural gas-fired combined cycle plant. The steam to be supplied by Martin Solar will be used to supplement the steam currently generated by the heat recovery steam generators. The project will involve the installation of parabolic trough solar

collectors that concentrate solar radiation. The collectors will track the sun to maintain the optimum angle to collect solar radiation. The collectors will concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce the steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Q. What are the major project milestones for Martin Solar?

A. The major project milestones for Martin Solar are included in Exhibit ES-1. In order to achieve the currently targeted final in-service date by the end of 2010, numerous engineering, permitting and procurement activities are underway in 2008.

The permitting process commenced with the initial submittal of an Application for Site Certification Modification to the Florida Department of Environmental Protection ("FDEP") on May 1, 2008. The application was deemed complete on June 2, 2008. On July 7, 2008 the FDEP issued a Notice of Intent to Modify Conditions of Certification. The final modification order, along with the issuance of an Army Corp of Engineers ("ACOE") Fill Permit Modification, is expected in September, 2008. With the necessary permits,

construction is expected to commence by early 2009.

Initial engineering commenced during July 2008 in order to support the specification and procurement of major equipment such as mirrors, heat collection elements, solar collection assemblies and heat exchangers. The selection and procurement of mirror and heat collection element suppliers is expected to be complete by the end of the November, 2008. The selection and procurement of the solar collection assemblies and heat exchanger suppliers is expected to be complete by the end of 2008. Contracts for the construction of both the solar fields and the tie-in into the existing Martin Unit 8 plant are expected to be complete by the end of 2008 to support the start of construction.

Q. What costs for the Martin Solar project do you expect to incur in 2008 for which you are requesting recovery for under ECRC?

A. The expected costs for 2008 are $17,710,000.

Q. What costs have been incurred to date?

A. The costs incurred through the end of June, 2008 for the Martin Solar project are $766,731. Included in this amount is approximately $68,300 which was incurred in late 2007 as part of the initial site zoning amendment effort.

Q. Please describe the activities for which costs have been incurred to date.

A. The majority of costs incurred to date consisted of payroll and

contracted services for the initial development of the project's site certification modification, zoning amendment and the associated conceptual engineering to support the development of these applications.

Q. What costs are projected for the remainder of 2008?

A. The current projected costs for July, 2008 to the end of December, 2008 are $16,943,269.

Q. Please describe the activities for which costs are projected during the remainder of 2008.

A. A majority of the projected costs, about $10.6 million, are for initially securing the necessary mirrors and heat collection elements for the project. These orders are expected to be placed by the end of November, 2008 in order to support the current project schedule. Costs for engineering, procurement of solar collection assemblies and heat exchangers, and development of the construction packages during the remainder of 2008 make up the balance of these costs.

Q. What is the current projected total capital cost for the Martin Solar project?

A. The current projected total capital cost for the Martin Solar Project is $476.3 million.

Q. What steps is FPL taking to ensure that the costs for this project are prudent and reasonable?

A. FPL is using trained and qualified employees with extensive experience in designing, procuring, and constructing utility facilities in

Florida to develop the Martin Solar project. Through the leveraging of shared resources, FPL is also calling on the experience and expertise of its sister company, FPL Energy, which owns and operates the world's largest solar thermal facility, the 310 MW Solar Electric Generating System ("SEGS") in California that has produced reliable renewable solar power for about 20 years. FPL Energy has performed a global assessment of solar equipment providers for upgrade work performed at SEGS and for ongoing development efforts for other large solar thermal plants in California and internationally. These assessments have revealed that globally there are a limited number of solar equipment suppliers and all have manufacturing capacity constraints. Additionally, there are a limited number of companies with recent experience in the engineering and construction, including on-site assembly and erection, of solar thermal fields. As a result competitive bidding of all aspects for the Martin project may not be feasible or necessary, however, FPL expects to achieve design, procurement, and construction efficiencies for the benefit of its customers by having its own highly qualified employees leverage the expertise, international relationships and experience gained by its sister company FPL Energy.

FPL'S PROPOSED DESOTO NEXT GENERATION SOLAR ENERGY CENTER ("DESOTO SOLAR")

Q. Please provide an overview of FPL's proposed DeSoto Solar project.

A. The DeSoto Solar project will be built utilizing solar photovoltaic ("PV") technology. The project is planned to be 25 MW of capacity and is projected to produce an average of 51,000 MWh of electricity annually. Construction of the plant is planned to begin during the first quarter of 2009 with an in-service date during the fourth quarter of 2009.

Q. Please describe the solar energy technology that will be used for the DeSoto Solar project.

A. DeSoto Solar will utilize solar PV technology that converts sunlight directly into electric power. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility will utilize cutting edge solar panel technology.

Q. What are the major project milestones for DeSoto Solar?

A. The major project milestones for DeSoto Solar are included in Exhibit ES-2. In order to achieve the currently targeted final in-service date of the end of 2009, numerous engineering, permitting and procurement activities are underway in 2008. Such activities include layout and design of the solar fields, procurement of the PV solar panels and associated electrical equipment, and interaction with the FDEP for the

Environmental Resource Permit.

Q. What costs for the DeSoto Solar project do you expect to incur in 2008 for which you are requesting recovery for under ECRC?

A. The expected costs for 2008 are $6,296,363.

Q. What costs have been incurred to date?

A. The costs incurred through the end of June, 2008 for the DeSoto Solar project are $257,539.

Q. Please describe the activities for which costs have been incurred to date.

A. The majority of costs incurred to date consisted of payroll and contracted services for the development of the project's local land use approvals, environmental studies, and conceptual engineering to support the preparation of the storm water management system design. Additionally, engineering effort was expended for the preparation of specifications used in the competitive bid packages for solicitation of qualified Engineering Procurement Construction ("EPC") contractors.

Q. What costs are projected for the remainder of 2008?

A. The current projected costs for July 2008 to the end of December 2008 are $6,038,824.

Q. Please describe the activities for which costs are projected during the remainder of 2008.

A. A majority of the projected costs, about $4 million, for the remainder of 2008 are for progress payments to the turnkey EPC contractor. Costs

for administration of the contract, permitting and internal engineering, legal and project management make up the balance of the costs.

Q. What is the current projected total capital cost for the DeSoto Solar project?

A. The current projected total capital cost for the DeSoto Solar project is $173.5 million.

Q. What steps is FPL taking to ensure that these costs are prudent and reasonable?

A. FPL has entered into a turnkey EPC contract with a qualified supplier and contractor experienced in utility-scale projects. As part of the process, FPL followed a well-defined request for information ("RFI") process which was initially conducted in 2007 with responses from approximately 26 international and domestic companies involved in the development, manufacturing, and construction of utility-scale PV systems and projects. In February of 2008 a request for proposal ("RFP") was issued which resulted in responses from 8 companies of which 4 provided conforming proposals to the RFP. The 4 responses were short listed down to 2 proposals after obtaining bid clarifications and conducting an initial screening evaluation. A detailed bid evaluation along with initial negotiations with the 2 companies was conducted which resulted in a final selection.

The contract for the engineering, procurement and construction of the DeSoto Solar project is with SunPower of San Jose, California. In

addition to other large scale PV projects, SunPower built the largest-operating solar PV power plant in North America, a 14-megawatt installation located at Nellis Air Force Base in Nevada.

FPL'S PROPOSED SPACE COAST NEXT GENERATION SOLAR ENERGY CENTER ("SPACE COAST SOLAR")

Q. Please provide an overview of FPL's Space Coast Solar project.

A. Space Coast Solar will utilize solar PV technology and will be located at NASA's Kennedy Space Center, Florida. The project is planned for 10 MW of installed capacity that is projected to produce approximately 17,000 MWh of electricity annually. Construction of the project is expected to begin as early as the third quarter of 2009 with an in-service date during the third quarter of 2010.

Q. Please describe the solar energy technology that will be used for the Space Coast Solar project.

A. Space Coast Solar project uses the solar PV, which I previously described with respect to the DeSoto Solar project. However, the Space Coast Solar project will deploy this technology differently in that we will utilize a fixed array oriented to capture the maximum amount of electricity from the sun over the entire year.

Q. What are the major project milestones for Space Coast Solar?

A. The major project milestones for Space Coast Solar are included in Exhibit ES-3. In order to achieve the currently targeted final in-service

date during the third quarter of 2010, numerous engineering, permitting and procurement activities are underway in 2008. Such activities include layout and design of the PV solar fields and obtaining the Environmental Resource Permit from FDEP.

Q. What costs for the Space Coast Solar project do you expect to incur in 2008 for which you are requesting recovery for under ECRC?

A. The expected costs for 2008 are $1,012,286.

Q. What costs have been incurred to date?

A. The costs incurred through the end of June 2008 for the Space Coast Solar project are $269,960. Included in this amount was approximately $37,000 which was incurred in late 2007 which included the initial development efforts for acquiring the site.

Q. Please describe the activities for which costs have been incurred to date.

A. The majority of costs incurred to date consisted of payroll and contracted services for the initial development of the project's site long term land lease, conceptual engineering to support the preparation of boundary and topographic surveys, conceptual surface water management system design, and completion of an environmental assessment. Additionally, engineering effort was expended for the preparation of specifications used in the competitive bid packages for solicitation of qualified EPC contractors.

Q. What costs are projected for the remainder of 2008?

A. The current projected costs for July 2008 to the end of December 2008 are $742,326.

Q. Please describe those activities for which costs are projected during the remainder of 2008.

A. The projected costs for the remainder of 2008 are for administration of the contract, permitting and internal engineering, legal and project management.

Q. What is the current projected total capital cost for the Space Coast Solar project?

A. The current projected total capital cost for the Space Coast Solar project is $80 million, which includes the net present value of the land lease for the property.

Q. What steps is FPL taking to ensure that these costs are prudent and reasonable?

A. FPL has entered into a turnkey EPC contract with a qualified supplier and contractor experienced in utility-scale projects. As part of the process, FPL followed a well-defined request for information ("RFI") process which was initially conducted in 2007 with responses from approximately 26 international and domestic companies involved in the development, manufacturing, and construction of utility-scale PV systems and projects. In February of 2008 a request for proposal ("RFP") was issued which resulted in responses from 8 companies of which 4 provided conforming proposals to the RFP. The 4 responses

were short listed down to 2 proposals after obtaining bid clarifications and conducting an initial screening evaluation. A detailed bid evaluation along with initial negotiations with the 2 companies was conducted which resulted in a final selection.

The contract for the engineering, procurement and construction of the Space Coast Solar project is with SunPower of San Jose, California. As previously mentioned, in addition to other large scale PV facilities, SunPower built the largest-operating solar PV power plant in North America, a 14-megawatt installation located at Nellis Air Force Base in Nevada.

MANAGEMENT OF PROJECT COSTS

Q. Will FPL report to the Commission as part of ongoing ECRC cost-recovery proceedings the construction costs, in-service costs, operating and maintenance costs, hourly energy production and any other information required by the Commission?

A. Yes. This information will be provided as part of FPL's ongoing ECRC filings.

Q. Is FPL recovering through any other mechanism the costs for the Martin Solar, DeSoto Solar or Space Coast Solar projects for which it is petitioning for ECRC recovery?

A. No. FPL will apply ECRC incremental cost principles to its cost

recovery requests for the solar projects. This will ensure that only the correct incremental costs of the solar projects are included for ECRC recovery.

Q. How much in total does FPL project these projects to cost?

A. Based upon the information available at the time of this filing, FPL estimates that the total capital cost of the projects is about $729.8 million, not including interest during construction. This is within the range of costs described in FPL's petition and my testimony in Docket Number 080281-EI, where the Commission approved these projects as eligible for ECRC recovery. However, the projected annual average output for the two PV projects has increased from approximately 58,000 MWh to 68,000 MWh which is a result of the specific technology and supplier selected. Therefore, the levelized installed cost on a dollar per megawatt hour ($/MWh) basis is in line with estimates previously provided in my testimony.

Q. Are there uncertainties with respect to the costs of the projects, and what is FPL doing to mitigate those uncertainties?

A. There are unavoidable uncertainties associated with these projects. FPL is providing the best available information with respect to the costs of the projects at this stage of development. However, all the projects are subject to pricing changes, to the benefit or otherwise, due to the global volatility of key commodities such as steel, copper, concrete and silicone. Additionally, fluctuations in the value of the U.S. dollar could impact, either positively or negatively, final project

pricing since many key components are currently manufactured overseas.

With respect to DeSoto Solar and Space Coast Solar, final agreements have been negotiated and executed for solar PV panels and their installation. Cost uncertainties associated with these two projects have been greatly reduced.

Martin Solar does not yet have completed procurement and installation contracts. In addition, important aspects of the Martin Solar project are novel in the industry. Designing and implementing new technology is less certain than designing and implementing well-established technology, such as gas-fired combined cycle plants.

FPL is taking advantage of solar thermal lessons learned from FPL Energy's SEGS plant and its current efforts on a 250 MW project in California. FPL also intends to fully leverage its buying power due to the large economies of scale of these projects to reduce costs. Access to such existing expertise and buying power with respect to solar steam generation is invaluable. However, the integration proposed for Martin Solar -- namely, to provide the solar generated steam into an existing combined cycle plant as a substitute for steam generated from combusting natural gas -- has not previously been done. This gives rise to cost and technical uncertainties that have not

been resolved at this stage of the project. FPL will use thorough due diligence, careful contract negotiation and other appropriate measures to manage such risks.

Q. Are there any additional project cost exposures in the event that the projects not proceed for any reason?

A. Yes, we are estimating an additional $3.3 million in termination fees with various suppliers in the event the projects are terminated in 2008.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ERIC SILAGY

DOCKET NO. 080007-EI

August 29, 2008

Q. Please state your name and business address.

A. My name is Eric Silagy. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By who are you employed and what position do you hold?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Vice President and Chief Development Officer.

Q. Please describe your duties and responsibilities in that position.

A. I lead FPL's efforts to develop new electric generation, including the development of clean, zero greenhouse gas emitting renewable electric generation.

Q. Have you previously testified in this proceeding?

A. Yes I have.

PURPOSE AND SUMMARY

Q. What is the purpose of this testimony?

A. The purpose of my testimony is to present for Commission review and approval under the projected 2009 Environmental Cost Recovery

Clause ("ECRC") recoverable costs for the Martin Next Generation Solar Energy Center ("Martin Solar"), DeSoto Next Generation Solar Energy Center ("DeSoto Solar") and the Space Coast Next Generation Solar Energy Center ("Space Coast Solar").

Q. Would you please summarize your testimony?

A. In Order Number PSC-08-0491-PAA-EI, issued in Docket Number 080281-EI on August 4, 2008, the Commission found that the Martin Solar, DeSoto Solar and Space Coast Solar projects are eligible for recovery through the ECRC pursuant to House Bill 7135 (the "Energy Bill"). On August 4, 2008, I filed testimony in this proceeding that provided overviews of the Energy Bill and each of these three projects, as well as presenting the reasonable actual and estimated costs for each project through the end of 2008. In this testimony, I discuss the activities planned for each project in 2009 and present FPL's projection of the reasonable costs to be incurred in 2009. Those costs should be recovered through the ECRC.

MARTIN SOLAR PROJECT

Q. What are the 2009 major project milestones for Martin Solar?

A. The major project milestone in 2009 for Martin Solar is the commencement of construction in the first quarter of 2009, with the possible commissioning of a portion of the solar field in December 2009. The Martin Solar project is currently in the process of design

and optimization of the layout and configuration. Once completed later this year, then an estimate of the amount of generation that could be placed into service by the end of 2009 can be established.

Q. What costs for the Martin Solar project do you expect to incur in 2009 for which you are requesting recovery under ECRC?

A. FPL expects to incur capital costs for 2009 of $210,005,000.

Q. Please describe the activities for which these costs are projected to be incurred in 2009.

A. The projected 2009 costs are primarily split between material and equipment costs of approximately $90 million and construction costs of approximately $120 million. Included in the equipment and material category are costs related to solar mirrors, heat collection tubes, support structures, heat transfer fluid, and the solar field heat exchanger/steam generator. Included in the construction category are costs related to site clearing and grading, stormwater system installation, transmission line relocation, solar field construction, balance of plant construction, and owner project management costs.

Q. What is the current projected total capital cost for the Martin Solar project?

A. The current projected total capital cost for the Martin Solar Project is $476.3 million.

Q. What steps is FPL taking to ensure that the 2009 costs for this project are prudent and reasonable?

A. As discussed in the testimony I filed on August 4, 2008, FPL is using trained and qualified employees with extensive experience in designing, procuring, and constructing utility facilities in Florida to develop the Martin Solar project. Through the leveraging of shared resources, FPL is also calling on the experience and expertise of its sister company, FPL Energy, which owns and operates the world's largest solar thermal facility, the 310 MW Solar Electric Generating System ("SEGS") in California that has produced reliable renewable solar power for about 20 years. FPL Energy has performed a global assessment of solar equipment providers for upgrade work performed at SEGS and for ongoing development efforts for other large solar thermal plants in California and internationally. These assessments have revealed that globally there are a limited number of solar equipment suppliers and all have manufacturing capacity constraints. Additionally, there are a limited number of companies with recent experience in the engineering and construction, including on-site assembly and erection, of solar thermal fields. As a result, competitive bidding of all aspects for the Martin project may not be feasible or necessary, however, FPL expects to achieve design, procurement, and construction efficiencies for the benefit of its customers by having its own highly qualified employees leverage the expertise, international

relationships and experience gained by its sister company FPL Energy.

DESOTO SOLAR PROJECT

Q. What are the major 2009 project milestones for DeSoto Solar?

A. The major project milestones in 2009 for DeSoto Solar are the commencement of construction in the first quarter of 2009, with project completion expected in December. The solar field is expected to be commissioned in 5 MW stages beginning in July and continuing until the end of December, at which time FPL expects the entire 25 MW to be in service.

Q. What costs for the DeSoto Solar project do you expect to incur in 2009 for which you are requesting recovery under ECRC?

A. The expected costs for 2009 are $166,429,700. Of this total, $467,475 is for operation and maintenance ("O&M") expenses with the remainder being capital costs.

Q. Please describe the activities for which these costs are projected to be incurred in 2009.

A. The capital costs will be associated with site grading and preparation, civil, mechanical and electrical construction of the PV solar field and equipment, testing, start-up and commissioning, and electrical interconnection, all of which FPL expects will be completed in 2009. In parallel, FPL will incur O&M expenses as phased turnover and

commissioning of sections of the PV solar field commence, beginning in the third quarter of the year.

Q. What is the current projected total capital cost for the DeSoto Solar project?

A. The current projected total capital cost for the DeSoto Solar project is $173.5 million.

Q. What steps is FPL taking to ensure that these costs are prudent and reasonable?

A. As discussed in the testimony I filed on August 4, 2008, FPL has entered into a turnkey EPC contract with a highly qualified supplier and contractor experienced in utility-scale projects. As part of the process, FPL followed a well-defined request for information ("RFI") process which was initially conducted in 2007 with responses from 26 international and domestic companies involved in the development, manufacturing, and construction of utility-scale PV systems and projects. In February of 2008 a request for proposal ("RFP") was issued which resulted in responses from eight companies of which four provided conforming proposals to the RFP. The four responses were short listed down to two proposals after obtaining bid clarifications and conducting an initial screening evaluation. A detailed bid evaluation along with initial negotiations with the two companies was conducted which resulted in a final selection.

The contract for the engineering, procurement and construction of the

DeSoto Solar project is with SunPower of San Jose California. In addition to other large scale PV projects, SunPower built the largest-operating solar PV power plant in North America, a 14 MW installation located at Nellis Air Force Base in Nevada.

SPACE COAST SOLAR PROJECT

Q. What are the major 2009 project milestones for Space Coast Solar?

A. The major project milestones in 2009 for Space Coast Solar are the receipt of all necessary permits and approvals during the first quarter of 2009 in order to support the commencement of construction in September, 2009. The solar field is expected to be commissioned in 2 MW stages beginning in May, 2010 and continuing until the end of July, 2010, at which time FPL expects the entire 10 MW to be in service.

Q. What costs for the Space Coast Solar project do you expect to incur in 2009 for which you are requesting recovery under ECRC?

A. The expected costs for 2009 are $27,030,686. Of this total $20,000 is for O&M expenses associated with the property lease from the federal government.

Q. Please describe the activities for which these costs are projected to incur in 2009.

A. Costs for 2009 will be inclusive of site engineering, design,

procurement of key components, extensive ground preparation and site work, civil construction activities and transmission interconnect work. Additionally there will be O&M costs associated with the property lease from the federal government.

Q. What is the current projected total capital cost for the Space Coast Solar project?

A. The current projected total capital cost for the Space Coast Solar project is $78.9 million, which includes the net present value of the land lease for the property. This projected total capital cost has been reduced by $1.1 million from the cost provided in the testimony I filed on August 4, 2008. The reduction is a result of cost savings recently identified due to more defined scope.

Q. What steps is FPL taking to ensure that these costs are prudent and reasonable?

A. The Space Coast Solar project is being handled as a turnkey EPC contract with SunPower, in the same manner as the DeSoto Solar project. My previous comments on the steps FPL is taking to ensure that the costs for the DeSoto Solar project are reasonable and prudent apply equally here.

TOTAL PROJECT COSTS

Q. Is FPL recovering through any other mechanism the 2009 projected costs for the Martin Solar, DeSoto Solar or Space Coast

Solar projects for which it is seeking ECRC recovery?

A. No. FPL will apply ECRC incremental cost principles to its cost recovery requests for the solar projects. This will ensure that only the correct incremental costs of the solar projects are included for ECRC recovery.

Q. In your August 4, 2008 testimony, you stated that FPL estimates the total costs of the three projects to be about $729.8 million. Has FPL's estimate of the total project costs changed?

A. Yes, for reason discussed in my testimony for the Space Coast Solar project, the total costs of the three projects have been reduced to $728.7 million.

Q. Your August 4, 2008 testimony discussed the uncertainties with respect to project costs and what FPL is doing to mitigate those uncertainties. Has your assessment of the uncertainties or FPL's response to the uncertainties changed?

A. No.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

WILL GARRETT

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

April 2, 2008

Q. Please state your name and business address.

A. My name is Will Garrett. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC as Controller of Progress Energy Florida.

Q. What are your responsibilities in that position?

A. As legal entity Controller for Progress Energy Florida (PEF), I am responsible for all accounting matters that impact the reported financial results of this Progress Energy Corporation entity. I have direct management and oversight of the employees involved in PEF Regulatory Accounting, Property Plant and Materials Accounting, and PEF Financial Reporting and General Accounting.

Q. Please describe your educational background and professional experience.

A. I joined the company as Controller of PEF on November 7, 2005. My direct relevant experience includes 2 ½ years as the Corporate Controller for DPL, Inc. and its major subsidiary, Dayton Power and Light, headquartered in Dayton, Ohio. Prior to this position, I held a number of finance and accounting positions for 8 years at Niagara Mohawk Power Corporation, Inc. (NMPC) in Syracuse, New York, including Executive Director of Financial Operations, Director of Finance and Assistant Controller. As the Director of Finance and Assistant Controller, my responsibilities included regulatory proceedings, rates, and financial planning, providing testimony on a variety of matters before the New York Public Service Commission. Prior to joining NMPC, I was a Senior Audit Manager at Price Waterhouse (PW) in upstate New York, with 10 years of direct experience with investor owned utilities and publicly traded companies. I am a graduate of the State University of New York in Binghamton, with a Bachelor of Science in Accounting and I am a Certified Public Accountant in the State of New York.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause (ECRC)?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval, Progress Energy Florida's Actual True-up costs associated with Environmental Compliance activities for the period January 2007 through December 2007.

Q. Are you sponsoring any exhibits in support of your testimony?

A. Yes. I am sponsoring Exhibit No. WG-1, which consists of eight forms and Exhibit No. WG-2, which provides details of four capital projects by site.

Exhibit No. WG-1 consists of the following:

- Form 42-1A reflects the final true-up for the period January 2007 through December 2007.
- Form 42-2A reflects the final true-up calculation for the period.
- Form 42-3A reflects the calculation of the Interest Provision for the period.
- Form 42-4A reflects the calculation of variances between actual and estimated/actual costs for O&M activities.
- Form 42-5A presents a summary of actual monthly costs for the period of O&M activities.
- Form 42-6A reflects the calculation of variances between actual and estimated/actual costs for Capital Investment Projects.
- Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects.

- Form 42-8A, pages 1 through 13, consist of the calculation of depreciation expense, property tax expense, and return on capital investment for each project that is being recovered through the ECRC.

Exhibit No. WG-2 consists of detailed support for the following capital projects:

- Above Ground Storage Tank Secondary Containment (CPD, pages 2 through 6)
- CAIR/CAMR (CPD, pages 7 through 8)
- CAIR CTs (CPD, pages 9 through 12)
- Underground Storage Tanks (CPD, page 13).

Q. What is the source of the data that you will present by way of testimony or exhibits in this proceeding?

A. The actual data is taken from the books and records of PEF. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by Federal Energy Regulatory Commission (FERC) and any accounting rules and orders established by this Commission.

Q. What is the final true-up amount for which PEF is requesting for the period January 2007 through December 2007?

A. PEF is requesting approval of an over-recovery amount of $2,219,585 for the calendar period ending December 31, 2007. This amount is shown on Form 42-1A, Line 1.

Q. What is the net true-up amount PEF is requesting for the January 2007 through December 2007 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/recovered in the next projection period?

A. PEF has calculated and is requesting approval of an over-recovery amount of $5,553,115 reflected on Line 3 of Form 42-1A, as the adjusted net true-up amount for the January 2007 through December 2007 period. This amount is the difference between the actual over-recovery amount of $2,219,585 and the actual/estimated under-recovery of $3,333,530, as approved in Order PSC-07-0922-FOF-EI, for the period of January 2007 through December 2007.

Q. Are all costs listed in Forms 42-1A through 42-8A attributable to environmental compliance projects approved by the Commission?

A. Yes, they are.

Q. How did actual O&M expenditures for January 2007 through December 2007 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?

A. Form 42-4A shows that total O&M project costs were $6,212,976 or 16.6% lower than projected. Following are variance explanations for those O&M projects with significant variances. Individual project variances are provided on Form 42-4A.

O&M Project Variances

1. **Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project No. 2)**: Project expenditures were $934,169 or 5.5% lower than projected. This variance is primarily attributable to the inability to complete the number of remediations projected for the last quarter of 2007. This project is further discussed in Donald R. Ennis's testimony.

2. **Pipeline Integrity Management Program (Project No. 3a)**: The Pipeline Integrity Management (PIM) O&M project expenditures were $338,637 or 43.0% lower than projected. The majority of the variance is being driven by delays on several projects due to design modifications and unavailability of contractors. This project is further discussed in Patricia Q. West's testimony.

3. **SO2 Emissions Allowances Program (Project No. 5)**: The SO2 Emissions Allowances O&M project expenditures were $4,804,794 or 53.1% lower than projected. The majority of the variance is being driven by an adjustment of $4,885,084 related to the SO2 Allowance Auction Proceeds liability. Since

2000, the liability was adjusted downward based on information that the allowances were vintage years of seven years in the future. During the third quarter of 2007, a detailed investigation into allowance auctions determined that these proceeds related to allowances that had current year vintages and seven year vintages. Thus, an adjustment was needed to reduce the liability for allowances with vintage years that had already passed and to properly accelerate the benefit to the ratepayers through a reduction in expenses. In the Estimated/Actual filing, the liability was reduced, but the corresponding offset to SO2 expenses was not recorded due to oversight. Upon the approval of the Estimated/Actual filing by the Commission, an adjustment was recorded in December 2007 to flow the benefits through recoverable ECRC expenses. The recognition of the adjustment at the end of the year benefited ratepayers through a decreased return on capital.

4. **Sea Turtle – Coastal Street Lighting (Project No. 9)**: Project expenditures were $97,400 or 79.5% lower than expected. This variance is attributable to delays with the lighting research that was planned and not fully completing compliance activities in certain areas. This project is further discussed in Donald R. Ennis's testimony.

Q. How did actual Capital recoverable expenditures for January 2007 through December 2007 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?

A. Form 42-6A shows that total Capital Investment project recoverable costs were $377,653 or 17.8% higher than projected. Actual costs and variance by individual project are provided on Form 42-6A. Return on Capital Investment, Depreciation, and Taxes for each project for the period are provided on Form 42-8A, pages 1 through 13. The variance explanations for those Capital projects with significant variances are as follows:

Capital Investment Project Variances:

1. **SO2/NOX Emissions Allowances (Project No. 5):** Recoverable costs were $359,084 or 54.7% higher than projected. At the time of the Estimated/Actual filing, prices for NOX allowances were highly volatile and unpredictable because the market for these allowances was a new compliance market. As a result, there was a high degree of uncertainty related to the timing and amount of NOX allowance purchases in the future. PEF applied a conservative approach for projected NOX allowance purchases, where by rates would only include a return on capital for purchases certain to occur during the second half of 2007. NOX allowance purchases were only projected in inventory balances if there was an executed contract with a transaction that was expected to settle during the year. The variance is primarily attributable to the return on incremental NOX allowances purchases that did not have executed contracts at the time of the Estimated/Actual filing and transactions that settled in 2007 that were projected to settle in 2008.

Q. How did actual Crystal River CAIR/CAMR - Base (Project No. 7.4) capital expenditures for January 2007 through December 2007 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?

A. These capital expenditures qualify for AFUDC and therefore will not be included in the capital recoverable costs until the associated pollution controls are placed in service. PEF projected total capital expenditures to be $281,068,748 in 2007 as part of the Estimated/Actual filing. Actual expenditures in 2007 were $15,345,702 or 5.5% higher than projected. The variance is primarily attributable to having only an estimated cash flow of expenses for the main contractor at the time of the Estimated/Actual filing. This project is further discussed in Patricia Q. West's testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DONALD R. ENNIS

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

April 2, 2008

Q. Please state your name and business address,

A. My name is Donald R. Ennis. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolina as Manager, Environmental Permitting & Compliance.

Q. What is the scope of your duties?

A. Currently, my responsibilities include managing environmental permitting and compliance activities for the Energy Delivery Florida and Energy Delivery Carolinas organizations.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in Biology from Campbell University. In addition, I am a Registered Environmental Manager with the National

Registry of Environmental Professionals. Currently I hold the position of Manager, Environmental Permitting & Compliance. Prior to my current assignment, I held several environmental management positions with Progress Energy Carolina and Progress Energy Service Company, LLC.

Q. What is the purpose of your testimony?

A. My testimony provides Progress Energy Florida's Actual True-Up costs associated with the following environmental compliance activities for the period January 2007 through December 2007: Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project No.2) and Sea Turtle – Coastal Street Lighting (Project No.9).

Q. How did actual O&M expenditures for January 2007 through December 2007 compare with PEF's estimated / actual projections as presented in previous testimony and exhibits?

A. Details regarding each of the identified projects are provided below:

O&M Project Variances:

1. **Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project No.2):** Actual O&M expenditures were $934,169 or 5.5% less than projected. This variance is primarily due to a lower number of sites being remediated than re-projected for the 2007 work plan caused by resource and scheduling issues during the fourth quarter. Remediation work planned, but not completed in 2007, is included in the

2008 work plan. Progress Energy Florida implemented further changes to our work process to better optimize resource planning and scheduling.

2. **Sea Turtle – Coastal Street Lighting (Project No.9):** Actual O&M expenditures were $97,400 or 79.5% lower than projected. This variance is attributable to a delay in conducting lighting research that was planned and not fully completing street light fixture modifications in the Mexico Beach area. Progress Energy Florida has partnered with the University of Florida to conduct research on identifying lighting characteristics that are not adverse to sea turtle hatchlings. This research is intended to be used to develop new lighting technology that will add to the limited compliance options that currently exist. The research was delayed until 2008 to allow time to better develop the research components. Progress Energy Florida and the University of Florida finalized the research plan in late 2007 and research activities began in early 2008. Progress Energy Florida modified 123 street light fixtures at Mexico Beach in 2007. Additional street light fixture modifications were planned for Mexico Beach but were not completed because of resource and scheduling issues. These modifications are expected to occur in 2008.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DONALD R. ENNIS

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 4, 2008

Q. Please state your name and business address.

A. My name is Donald R. Ennis. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas as Manager, Environmental Permitting & Compliance.

Q. What are your responsibilities in that position?

A. Currently, my responsibilities include managing environmental permitting and compliance activities for the Energy Delivery Florida and Energy Delivery Carolinas organizations.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in Biology from Campbell University. In addition, I am a Registered Environmental Manager with the National

Registry of Environmental Professionals. Currently I hold the position of Manager, Environmental Permitting & Compliance. Prior to my current assignment, I held several environmental management positions with Progress Energy Carolina and Progress Energy Service Company, LLC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the Estimated/Actual project expenditures versus the original cost projections for environmental compliance costs associated with Progress Energy Florida (PEF)'s Substation Environmental Investigation, Remediation, and Pollution Prevention Program, Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program, and the Sea Turtle Coastal Street Lighting Program for the period January 2008 through December 2008.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Substation System Program for the period January 2008 to December 2008.

A. O&M project expenditures for the Substation System Program are estimated to be $2,736,930 or 125% higher than originally projected. This increase is primarily attributable to higher amounts of subsurface contamination encountered during remediation of substations that was not evident during the original visual environmental inspections.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Distribution System Program for the period January 2008 to December 2008.

A. O&M project expenditures for the Distribution System Program are estimated to be $427,507 or 3% higher than originally projected. The increase is driven by a higher unit cost than forecasted and the carryover of uncompleted work from the 2007 work plan. The higher unit costs are associated with remediation sites that took longer than one day (as originally projected) to complete because of soil conditions or extent of the contamination.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Sea Turtle Program for the period January 2008 to December 2008.

A. O&M project expenditures for the Sea Turtle Program are estimated to be $173,289 or 162% lower than originally projected. This decrease is attributable to lower than anticipated costs of the study to be conducted jointly with the University of Florida as part of the compliance program. The study is designed to further our understanding of the light spectrum which will be used to identify new and/or emerging lighting technologies that provide additional options for ensuring compliance with applicable sea turtle ordinances and criteria.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DONALD R. ENNIS

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 29, 2008

Q. Please state your name and business address.

A. My name is Donald R. Ennis. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas as Manager, Environmental Permitting and Compliance.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide estimates of the costs that will be incurred in the year 2009 for Progress Energy Florida's ("PEF's" or "Company's") Substation Environmental Investigation, Remediation, and Pollution Prevention Program (Project #1), which was previously approved in PSC Order No. PSC-02-1735-FOF-EI, Distribution System Environmental Investigation, Remediation, and Pollution Prevention Program (Project #2), which was previously approved in PSC Order No. PSC-02-1735-FOF-EI, and the Sea Turtle Coastal Street Lighting Program (Project #9), which was previously approved in PSC Order No. PSC-05-1251-FOF-EI.

Q. What costs do you expect to incur in 2009 in connection with the Substation System Investigation, Remediation and Pollution Prevention Program (Project #1)?

A. For 2009, we estimate PEF will incur total O&M expenditures of approximately $6.8 million in remediation costs for the Substation System Investigation, Remediation and Pollution Prevention Program. This amount includes estimated costs for remediation activities at 41 substation sites that have already been identified as requiring remediation.

Q. What steps is the Company taking to ensure that the level of expenditures for the Substation System Program is reasonable and prudent?

A. PEF works annually with the Florida Department of Environmental Protection ("FDEP") to determine the specific substation sites to be remediated to ensure compliance with FDEP criteria. The Company also provides quarterly reports to FDEP on progress made in remediating substation sites. To ensure the level of expenditures is reasonable and prudent, the Company selected contractors through a competitive bidding process and reviews invoices for accuracy.

Q. What costs do you expect to incur in 2009 in connection with the Distribution System Investigation, Remediation and Pollution Prevention Program (Project #2)?

A. For 2009 we estimate total O&M expenditures of approximately $8.3 million for the Distribution System Investigation, Remediation and Pollution Prevention Program to perform remediation activities at approximately 870 sites. This estimate assumes approximately 150 3-phase transformer sites at an average cost of $14,500 per site, approximately 730 single-phase transformer sites at an average cost of $8,500 per site as well as program management costs.

Q. What steps is the Company taking to ensure that the level of expenditures for the Distribution System program is reasonable and prudent?

A. To ensure the level of expenditures is reasonable and prudent, the Company closely monitors remediation work, performs sample testing of inspection results, and provides quarterly reports to the FDEP on progress made in remediating distribution sites.

Q. What costs do you expect to incur in 2009 in connection with the Sea Turtle/Street Lighting Program (Project #9)?

A. For 2009, the projected expenses for the Sea Turtle/Street Lighting Program are $25,000. This amount includes $5,000 in O&M costs and $20,000 in capital expenditures to satisfy to ensure compliance with sea turtle ordinances in Franklin and Gulf Counties and the City of Mexico Beach. The capital expenditures will be spent on modifications and/or replacement of applicable lighting fixtures. The estimated O&M projections include research costs associated with street light technology studies.

Q. What steps is the Company taking to ensure that the level of expenditures for the Sea Turtle/Street Lighting Program is reasonable and prudent?

A. PEF is cooperating with local governments and appropriate regulatory agencies to develop compliance plans that allow flexibility to make only those modifications necessary to achieve compliance. PEF will ensure that evaluation of each streetlight requiring modification occurs so that only those activities necessary to achieve compliance are performed in a reasonable and prudent manner. In addition, PEF will evaluate emerging technologies and incorporate their use where reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

April 2, 2008

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by the Environmental, Health and Safety Services Section of Progress Energy Florida ("Progress Energy" or "Company") as Manager of Environmental Services / Power Operations Group. In that position, I have responsibility to provide regulatory support and obtain necessary environmental permits for the implementation of compliance strategies pertaining to environmental requirements for power generation facilities in Florida.

Q. Please describe your background and experience in the environmental field.

A. I obtained my B.S. degree in Biology from New College of the University of South Florida in 1983. I was employed by the Polk County Health Department from 1983-1986 and by the Florida Department of Environmental Protection

("DEP") from 1986-1990. At DEP, I was involved in compliance and enforcement efforts associated with petroleum storage facilities. In 1990, I joined Florida Power Corporation as an Environmental Project Manager and then held progressively responsible positions in the company's environmental services department, including the position of team leader for the integration of the environmental functions of Florida Power and Carolina Power and Light. I previously served as Manager of Water Programs in the Environmental Services Section of PEF's Technical Services Department and as Manager of Environmental Programs and Strategy. In 2005, I assumed my present position as Manager of Environmental Services / Power Operations Group.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recovery Clause?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. This testimony provides Progress Energy Florida's Actual True-Up costs associated with the following environmental compliance activities for the period January 2007 through December 2007: the Pipeline Integrity Management Program (Project No. 3a); and Crystal River CAIR/CAMR - Base (Project No. 7.4).

In addition, I am sponsoring Exhibit No. __ (PQW-1), which is PEF's review of the efficacy of its Integrated Clean Air Compliance Plan and of retrofit options in relation to expected environmental regulations.

Q. How did actual O&M expenditures for January 2007 through December 2007 compare with PEF's estimated / actual projections as presented in previous testimony and exhibits?

A. Details regarding the identified project are provided below:

O&M Project Variance:

The Pipeline Integrity Management Program (Project No. 3a): The Pipeline Integrity Management (PIM) O&M project expenditures were $338,637 or 43.0% lower than projected. The majority of the variance was due to not completing the Main Line Valve (MLV) Telemetry project as planned in 2007; this delay is attributed to the need for design and installation modifications as well as the unavailability of contractors when work was scheduled. The installation of four MLV guardrails adjacent to Hwy. 19, that were intended to reduce the risk associated with potential traffic accidents along the roadway, was delayed to avoid conflicts with ongoing work on the MLV telemetry project. The majority of this work is included in the 2008 workplan. One guardrail will be postponed until FDOT completes their work along a portion of the highway, and is expected to be completed in 2010. In addition to these changes to the original project schedule, the Integrity Management Coordinator was temporarily assigned to other duties within Progress Energy between March and August 2007, and subsequently left the Company in November 2007.

Q. How did actual Crystal River CAIR/CAMR - Base (Project No. 7.4) capital expenditures for January 2007 through December 2007 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?

A. These capital expenditures for engineering, design, and construction of emission control facilities at Crystal River qualify for AFUDC and therefore will not be included in the recoverable costs until the associated pollution controls are placed in service. Progress Energy projected total capital expenditures to be $281,068,748 in 2007. Actual expenditures were $15,345,702 or approximately 5.5% more than expected because the primary contract for engineering, procurement, construction, and project management ("EPC contract") was not finalized until the fourth quarter of 2007. Therefore, at the time of the Estimated/Actual filing, expenses were projected based on an estimated cash flow. A definitive monthly cash flow of expenses was not available until the contract was signed.

Q. In Order No. PSC-07-0922-FOF-EI issued in Docket 070007-EI on November 16, 2007, the Commission 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." Has PEF conducted such a review?

A. Yes. PEF's review is presented in Exhibit No. __ (PQW-1) to my testimony.

Q. Please summarize the conclusions of PEF's review.

A. 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 significant project milestones, including execution of all major contracts and commencement of construction activities, including installation of steel support for the Crystal River Unit 4 and 5 control projects. As discussed in Exhibit No. __ (PQW-1), there are uncertainties associated with all major construction projects including the Crystal River pollution control projects. At this time, however, the Crystal River projects are on-schedule to achieve compliance with the applicable regulations as contemplated in PEF's 2007 ECRC filings.

No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. Although discussion of potential regulation of carbon dioxide (CO_2) emissions continues, no legislation or regulations have been adopted to date. In any event, 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 CAIR regulatory deadlines and it would put PEF in the vulnerable position of relying solely on allowance purchases to achieve compliance during

the five to six year interim period. Furthermore, replacing coal-fired generation with gas-fired generation would decrease PEF's fuel diversity and potentially increase fuel price volatility.

As a result of a recent federal appeals court decision vacating the federal CAMR regulations, the U.S. Environmental Protection Agency (EPA) may be required to adopt 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. Thus, Plan D provides PEF flexibility to respond if and when EPA adopts any new mercury standards. PEF does plan to continue ongoing design of Continuous Mercury Monitors (CMMS) for Crystal River Units 1 and 2 because significant work has already been started and CMMS will likely be required in any rule the EPA adopts in response to the federal court's vacature of CAMR.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 4, 2008

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by the Environmental Health and Safety Services Section of Progress Energy Florida ("Progress Energy" or "Company") as Manager of Environmental Services / Power Generation Florida.

Q. What are your responsibilities in that position?

A. I am responsible for ensuring that environmental technical and regulatory support is provided to the implementation of compliance strategies associated with the environmental requirements for power generation facilities in Florida.

Q. Have you previously filed testimony before this Commission in connection with the Company's Environmental Cost Recovery Clause (ECRC)?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain material variances between the Estimated/Actual project expenditures and the original cost projections for environmental compliance costs associated with PEF's Pipeline Integrity Management Program, Aboveground Storage Tank Secondary Containment Program, Phase II Cooling Water Intake Program, Arsenic Groundwater Standard Project, Clean Air Mercury Rule, and the components of Integrated Clean Air Compliance Program associated with the Anclote plant and combustion turbines for the period January 2008 through December 2008. I also will describe a new Greenhouse Gas Inventory and Reporting Program for which PEF is seeking recovery in this docket.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Pipeline Integrity Management Program for the period January 2008 to December 2008.

A. PEF is projecting O&M expenditures to be $146,057 or 43% higher than previously projected, primarily because of an increase in the scope of work and the need to complete some activities in 2008 that were not completed in 2007.

This work primarily includes GIS database development, the installation of guardrails along US Highway 19 to protect valve mechanisms along the road right-of-way, installation of a pipeline telemetry system that allows remote monitoring of valves designed to isolate sections of the pipeline in the event of a leak, and leak detection software update.

PEF is projecting capital expenditures to be $332,707 or 51% higher for this program than originally projected. These costs will include higher than expected costs for the installation of the Pipeline Controls upgrade project, primarily due to additional scope items that had not been identified in the conceptual design for the project. Final design of the project has now been completed, material costs have been obtained, and bids for the installation work are being evaluated.

Q. Please explain the variance between the Estimated/Actual O&M expenditures and the original projections for the Above Ground Tank Secondary Containment Program for the period January 2008 to December 2008.

A. PEF is projecting O&M expenditures to be $368,303 higher than originally projected. This variance is due to costs for additional work necessary to bring Turner Tank 8 into compliance with the secondary containment requirements for Rule 62-761.510(3)(d), F.A.C. For Turner Tank 8, PEF originally selected EnviroMat secondary containment technology, which was selected off of the vendor approved list provided by the Florida Department of Environmental

Protection (FDEP). Field work to install the secondary containment began in September 2003. Acceptance testing was conducted in November 2003, but the EnviroMat system failed the 2 psi pressure leakage test. PEF terminated the fieldwork after repeatedly requesting the vendor to provide recommended corrective actions, but receiving no satisfactory responses. The vendor subsequently suggested remedial measures, but all attempts to resolve the problem failed. During the first quarter 2008, PEF concluded that all attempts at corrective action have been exhausted and that the technology cannot be corrected. Therefore, the costs associated with the failed technology approximately $368,303, has been deemed impaired and recorded to O&M. Rule 62-761.510(3), F.A.C., requires installation of secondary containment on Turner Tank 8 by 2010. To achieve compliance, the original technology will be removed and replaced with FDEP approved steel double-bottom technology as part of the 2008 remediation schedule.

Q. Please explain the variance between the Estimated/Actual capital expenditures and the original projections for the Above Ground Tank Secondary Containment Program for the period January 2008 to December 2008.

A. PEF is projecting capital expenditures to be $1,809,738 or 65% higher for this program than originally projected. This variance is primarily attributable to costs associated with completing the upgrades of two tanks at the Turner combustion turbine facility. The addition of the Turner tanks to the 2008 plan was based on the decision to proceed with final retrofits of Turner tank 8

(discussed above) as well as the decision to not retire Turner tank 7 in order to enhance fuel storage and flexibility within the PEF combustion turbine fleet. This work was scheduled in consideration of the DeBary work in order to minimize mobilization costs of contractors since the two plants are in close proximity to each other.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Phase II Cooling Water Intake Project for the period January 2008 to December 2008.

A. PEF is projecting O&M expenditures to be $38,128 or 26% lower than previously projected for this program. The variance is primarily attributable to lower than expected costs to complete reports summarizing the results of the completed biological studies. Work has been suspended on the project pending completion of additional rulemaking by the U.S. Environmental Protection Agency (EPA) in response to the Second U.S. Circuit Court of Appeals' vacatur of the Phase II cooling water intake rules in *Riverkeeper, Inc. v. EPA*, 475 F.3d 83 (2nd Cir. 2007) .

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Arsenic Groundwater Standard Project for the period January 2008 to December 2008.

A. PEF is projecting O&M expenditures to be $77,669 or 100% lower for this program than originally projected. PEF continues working with the FDEP to establish a compliance plan and schedule to address groundwater matters as well

as the management of solid waste / coal combustion product, in accordance with the FDEP Industrial Waste Water Permit that was issued on January 9, 2007 and the Conditions of Site Certification issued on November 29, 2007. Some of this work will continue into 2009 as PEF implements the management plan that must be submitted to the agency by December 31, 2008.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Clean Air Mercury Rule for the period January 2008 to December 2008.

A. PEF is projecting capital expenditures to be $1,572,669 or 58% lower for this program than originally projected. As reported in the April 2, 2008 review of the Integrated Clean Air Compliance Plant, on February 8, 2008 the federal CAMR regulations were vacated. This action resulted in the removal of requirements to install emissions monitoring equipment by January 1, 2009. The variance is primarily due to a PEF's actions in response to the court decision. In early 2008 PEF continued with ongoing design of the monitors for Crystal River Units 1 and 2 because significant work was already begun and CMMS will likely be required in any rule the EPA adopts in the future. PEF is also in negotiations with the provider of the monitoring equipment to avoid or minimize cost implications for equipment ordered prior to the rule vacatur.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the components of PEF's Integrated Clean Air Compliance Plan related to the Combustion Turbine

(CT) facilities and the Anclote plant for the period January 2008 to December 2008?

A. PEF is projecting capital expenditures for the Combustion Turbine (CT) projects to be $100,266 or 100% higher than projected primarily attributable to the need to complete certification testing of several emissions units early in 2008. The work was originally expected to be completed in late 2007, but extended into early 2008 due to unexpected outages during the time original testing was supposed to have commenced. The O&M costs for this project are expected to be $48,500 less than originally projected due to software support rates not being incurred during 2008.

PEF is projecting capital expenditures for the Anclote clean air compliance project to be lower than the original capital expenditure projection by $299,993 primarily attributable to the status of PEF's overall air compliance plan strategy assessment. Preliminary assessments for appropriate control technology will be undertaken during the latter part of 2008, with work expected to begin in early 2009.

Q. Have there been any recent developments concerning CAIR?

A. Yes. On July 11, 2008, the U.S. Circuit Court of Appeals for the District of Columbia issued a decision vacating CAIR in its entirety. The Court also remanded the rule back to the EPA to address the flaws identified by the Court. At this date, the decision is not final because Court has not issued a mandate. The Petitioners and EPA have 45 days, or until August 25, 2008, to petition for

rehearing of the Court's decision. The Court will then issue its mandate unless a petition for rehearing is granted. The Petitioners and EPA also can seek review by the U.S. Supreme Court within 90 days after the later of the Court's decision or completion of proceedings on a petition for rehearing.

At this time it is too early to determine the full impact of the Court's decision, even assuming it stands as originally issued. PEF is continuing to implement its Commission-approved Integrated Clean Air Compliance Plan as the Company assesses the potential implications of the Court's decision. We are working with state and federal agencies, as well as conducting internal analyses, to determine the appropriate course of action once the D.C. Circuit's decision becomes final and its full implications are known. We will update the Commission on the status of the CAIR decision and PEF's implementation of its clean air compliance plan in future testimony.

Q. Is PEF requesting recovery of 2008 costs for any new environmental programs?

A. Yes. PEF is requesting recovery of costs associated with a new Greenhouse Gas (GHG) Inventory and Reporting Program that is being implemented 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 new 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. Activities to be conducted in 2008 include training and inventory development. Project expenditures are projected to be $7,440 for the remainder of 2008.

Q. Do the costs for the new program qualify for recovery through the ECRC?

A. Yes. Chapter 2008-277, Florida Laws, establishes a new subsection 366.8255(1)(d)8, Florida Statutes, which provides for ECRC recovery of "[c]osts or expenses prudently incurred for the quantification, reporting, and third-party verification as required for participation in greenhouse gas emission registries for greenhouse gases as defined in s. 403.44." In addition, costs for the new program meet the requirements for ECRC recovery previously established by the Commission. Specifically, the expenditures are being prudently incurred after April 13, 1993; the activities are legally required to comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the minimum filing requirements (MFRs) were submitted in PEF's last rate case (Docket No. 050078-EI); and none of the costs of the new program are being recovered through base rates or any other cost recovery mechanism.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

August 29, 2008

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 299 1st Avenue North, St. Petersburg, Florida, 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by the Environmental Health and Safety Services Section of Progress Energy Florida ("PEF" or "Company") as Manager of Environmental Services / Energy Supply Florida.

Q. Have you previously filed testimony before this Commission in connection with PEF's Environmental Cost Recovery Clause?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. This testimony provides estimates of the costs that will be incurred in the year 2009 for environmental programs that fall within the scope of my responsibilities to support PEF's power generation group. These programs include the Pipeline Integrity Management Program (Project 3), the Aboveground Storage Tanks Secondary Containment Program (Project 4), the Phase II Cooling Water Intake 316(b) Program (Project 6), the Integrated Air Compliance Program associated with Anclote plant and combustion turbines, the Clean Air Mercury Rule, the Arsenic Groundwater Standard Program (Project 8), the Underground Storage Tank Program (Project 10), the Modular Cooling Tower Program (Project 11), and the Green House Gas Inventory and Reporting Program.

Q. What costs does the Company expect to incur in 2009 in connection with the Pipeline Integrity Management Program (Project 3)?

A. For 2009, we project that PEF will incur a total of $1,101,000 in operation and maintenance ("O&M") expenses and $60,000 in capital expenditures to comply with the Pipeline Integrity Management ("PIM") regulations (49 CFR Part 195).

PEF is projecting to spend $279,000 in O&M on PIM Program Implementation which includes general program management and oversight by PEF employees and contractors who assist with regulatory review, auditing and procedures management, document updates, High Consequence Area ("HCA") reviews, spill analyses, integrity assessment planning, pipeline mapping, data integration,

risk analyses, monitoring of program effectiveness, evaluation of preventive and mitigative measures to protect HCAs, and coordination of remedial actions to address integrity issues. An additional $732,000 in O&M will be required to run the internal inspection tools that detect, locate, and quantify corrosion and deformation anomalies along the pipeline; these inspections are required at intervals not to exceed five years and the baseline assessment was completed in 2004. The project will involve project planning and management, equipment specification, contract development, pipeline cleaning, a caliper tool run, placement of above ground markers for each tool run, a geometry tool run, an ultrasonic tool run, an inertial measurement unit run, interpretation of tool data, validation of results, rerunning any tools that do not provide complete and accurate results, third party review of results, completion of any emergency repairs, data integration, developing a reassessment interval, and planning long term repairs. PEF is projecting to spend $90,000 of O&M for risk reduction modifications to the pipeline.

PEF is projecting to spend $60,000 of capital in 2009 to complete the Supervisory Control and Data Acquisition ("SCADA") system replacement that began in 2007.

Q. What steps is the Company taking to ensure that the level of expenditures for the Pipeline Integrity Management Program is reasonable and prudent?

A. As additional work is identified to comply with the PIM regulations, PEF will identify qualified suppliers of the necessary services through a competitive bidding process where reasonable and appropriate.

Q. What costs do you expect to incur in 2009 in connection with the Aboveground Storage Tank Secondary Containment Program (Project 4)?

A. PEF is projecting to spend $1.337 million in capital expenditures in 2009. These costs are for the tank upgrade work at Higgins and Bartow which includes: cleaning the tank, performing required inspections, installing and testing new steel double bottom, preparing and coating new bottom and pipe modifications.

Q. What steps is the Company taking to ensure that the level of expenditures for the Aboveground Storage Tank Secondary Containment Program is reasonable and prudent?

A. As additional work is identified to comply with the Aboveground Storage Tank regulations, PEF will identify qualified suppliers of the necessary services through a competitive bidding process where reasonable and appropriate.

Q. What costs do you expect to incur in 2009 in connection with the Phase II Cooling Water Intake Program (Project 6)?

A. PEF is not anticipating any costs to be incurred in 2009.

Q. What costs do you expect to incur in 2009 in connection with the CAIR / CAMR Program (Project 7)?

A. As discussed in the testimony of PEF witness Michael Kennedy, PEF is moving forward with its Integrated Clean Air Compliance Plan to ensure that the Company can meet Clean Air Interstate Rule's ("CAIR's") imminent compliance deadlines in the event the U.S. Court of Appeals for the District of Columbia revisits its recent decision vacating CAIR. PEF witness Dale Wilterdink discusses the status of the Crystal River emission control components of the compliance plan. In addition, PEF will incur $67,700 in O&M expenditures for the new emission monitoring systems at the combustion turbine sites. PEF estimates that O&M costs for ongoing software vendor support of these new systems will be $43,700 in 2009 and $24,000 in air emissions testing costs in the event that emissions totals or maintenance activities require such testing.

Q. In your pre-filed testimony submitted on August 4, 2008, you stated that PEF is in negotiations with the provider of Continuous Mercury Monitoring System ("CMMS") equipment to avoid or minimize cost implications for equipment ordered prior to the vacatur of CAIR. What is the status of those negotiations?

A. The negotiations are still pending. Until these negotiations are finalized, PEF will not incur any further costs. As stated in Michael Kennedy's testimony, the Florida Department of Environmental Protection ("FDEP") is currently in the process of gathering data in an effort to adopt new rules establishing mercury

emission standards for various industrial sources, including coal-fired power plants. Due to the uncertainty around this program, PEF has assumed that payment will have to be made for the equipment at this time, but has not made any assumptions as to when it will be installed. To the extent actual costs are different than current projections, PEF will reflect this in future filings and these amounts will be subject to true-up.

Q. What costs do you expect to incur in 2009 in connection with the Arsenic Groundwater Standard Program (Project 8)?

A. PEF is currently working with FDEP to comply with the terms of the renewed industrial wastewater permit for the Crystal River Energy Complex (issued January 9, 2007) and the modified Conditions of Certification (issued November 29, 2007). Based upon discussions with the FDEP, PEF is projecting O&M expenditures of approximately $78,000. These costs are being deferred from 2008 because of delays in obtaining the renewed permit and will include groundwater study costs, results assessment, and possible remediation to address potential exceedances of the new standard.

Q. What steps is the Company taking to ensure that the level of expenditures for the Arsenic Groundwater Standard Program is reasonable and prudent?

A. As additional work is identified to comply with the new arsenic standard, PEF will identify qualified suppliers of the necessary services through a competitive bidding process where reasonable and appropriate.

Q. What costs do you expect to incur in 2009 in connection with the Underground Storage Tanks Program (Project 10)?

A. PEF is not anticipating any expenditures for this program during 2009.

Q. What costs do you expect to incur in 2009 in connection with the Modular Cooling Tower Program (Project 11)?

A. PEF is projecting to spend approximately $3.4 million in O&M expenditures in 2009 for rental fees associated with the five-year lease agreement that began in 2006. These costs are necessary to ensure compliance with the thermal discharge limit in the FDEP industrial wastewater permit for PEF's Crystal River plant while minimizing de-rates of PEF's Crystal River Units 1 and 2. *See* Order NO. PSC-07-0722-FOF-EI issued in Docket No. 060162-EI (Sep. 5, 2007). As discussed in the pre-filed testimony of PEF witness Daniel Roderick, PEF is implementing a new Thermal Discharge Compliance Project to provide a more permanent solution to the thermal discharge compliance issue.

Q. What costs do you expect to incur in 2009 in connection with the Green House Gas Inventory and Reporting Program?

A. PEF is projecting to spend approximately $56,680 in O&M in 2009. These costs are for annual Climate Registry fee as well as consulting fees and third-party verification of the inventory.

Q. What steps is the Company taking to ensure that the level of the expenditure for the Green House Gas Inventory and Reporting Program is reasonable and prudent?

A. In 2007 PEF issued a request for proposal to several consultants with expertise in this area. Bids were received and reviewed. A contract was established in November 2007 and the work through 2009 will be performed under this contract.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DALE WILTERDINK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 4, 2008

Q. Please state your name and business address.

A. My name is Dale W. Wilterdink. My business address is 15760 West Power Line Street, Crystal River, Florida 34428.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida ("PEF") as Manager of Plant Construction Projects.

Q. What are your responsibilities as Manager of Plant Construction Projects?

A. I serve as Project Manager for the Crystal River Units 4 and 5 air quality control system project ("Crystal River Project") included in PEF's Integrated Clean Air Compliance Plan, which the Commission approved in Docket No. 070007-EI. As Project Manager, I have primary overall responsibility and accountability for the Crystal River Project. I provide direct management of all aspects of the project, including the installation of Flue Gas Desulfurization ("FGD" or "scrubber"), Low

NOx Burners (LNBs), Selective Catalytic Reduction ("SCR") and other related activities, such as installation of a new stack, common limestone preparation/dewatering system, coal pile liners, ponding, and the water supply system. I also work with members of my project team to ensure that key stakeholders throughout the Company, including senior management, remain informed about the status of the Crystal River Project.

Q. Please describe your educational and background.

A. I received a B.S. degree in Chemistry and a Masters in Business Administration from Grand Valley State University. I have over twenty six years experience in the power industry, including direct project management for large, multi-unit air pollution control projects. Prior to joining Progress Energy, I worked air quality control system projects for URS Corporation, Advatech (a joint venture between URS and Mitsubishi Heavy Industries), Marsulex (formerly General Electric Environmental Services), and Grand Haven Board of Light and Power.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit No. __ (DW-1), which is an organization chart showing the organizational structure the Company has established for management and oversight of internal company personnel and contractors involved in the Crystal River Project.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the status of PEF's implementation of Crystal River Project, including Estimated/Actual project expenditures for 2008. I also will describe some of the measures PEF has taken to ensure that the costs incurred for the Crystal River Project are reasonable and prudent.

Q. What is the current status of the Crystal River Project?

A. The Crystal River Project is on schedule to meet the in-service dates set forth in the Integrated Clean Air Compliance Plan approved by the Commission in Docket No. 070007-EI. Over the past year, we have achieved several significant 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; and
- Completion of the Unit 5 FGD absorber tower in July, 2008.

As discussed in the annual review of PEF's compliance plan previously submitted in this docket, there are uncertainties associated with all major construction projects including the Crystal River Project. At this time, however, the Crystal River Project is on-schedule to achieve in-service dates set forth in PEF's Commission-approved Integrated Clean Air Compliance Plan.

Q. How do the Estimated/Actual project expenditures for the Crystal River Project compare with the original projections for the period January 2008 to December 2008?

A. We project that the total expenditures for the Crystal River Project in 2008 will be approximately $527 million, which is approximately $42 million less than projected in last year's docket. Of this difference, approximately $12 million is attributable to the fact that last year's projections were based on contract prices that were not finalized until PEF executed the Engineering Procurement and Construction (EPC) contract for the Project after the projects were submitted. The remaining variance is attributable to work on particulate controls for which PEF is no longer requesting ECRC recovery.

Q. What measures has the Company taken to minimize the risk of costs increases for the Crystal River Project?

A. Since the inception of the Crystal River Project, PEF has sought to minimize the risk of future cost increases to PEF and its customers and to allocate risk where it can be best managed. We implemented a contracting strategy that enabled PEF to negotiate contracts that mitigate the risk of price increases without jeopardizing construction time-frames necessary to ensure compliance with the applicable regulatory requirements. For the Engineering, Procurement and Construction (EPC) contract, which represents the majority of costs for the Crystal River Project, this strategy included an aggressive "open book" scoping assessment which enabled the Company to identify the costs for project components in detail to provide greater cost certainty. As part of the detail review process, Progress Energy personnel and outside engineers carefully reviewed the reasonableness of the scope and associated quantities of commodities, equipment, subcontracts, labor

and other project indirect components submitted by EPC contractor (Environmental Partners Crystal River or "EPCR"), as well as the prices quoted by EPCR.

We negotiated a portfolio of fixed price, lump sum contracts including the EPC contract, as well as contracts with the primary FGD and SCR design and procurement contractor (Babcock & Wilcox or "B&W"), and the vendors of major equipment such as scrubber towers (Stebbins Engineering and Manufacturing Company), flue gas chimney (Commonwealth Dynamics, Inc.), and SCR catalyst (CERAM Environmental, Inc.). These contracts, which PEF submitted for the Commission's review in last year's docket (Docket No. 070007-EI), also incorporate a payment milestone structure with associated liquidated damages to ensure timely performance. This contracting strategy has enabled PEF to mitigate cost and performance risks during a time period in which prices for material, equipment, and labor have increased substantially for major utility construction projects of this nature.

Q. Please describe the management structure being used to oversee implementation of the Crystal River Project?

A. PEF has established an organizational structure to ensure prudent decision-making and project oversight as implementation of the Integrated Clean Air Compliance Plan proceeds. The specific team for the Crystal River Project is as shown in Exhibit No.__(DW-1). The Company has assigned me to be the dedicated Project

Manager with primary overall responsibility and accountability for the Crystal River Project. I oversee all of the internal team members as well as all of the external contractors working on the project. My project management team, which also includes a dedicated Project Engineer and Project Controls personnel, regularly works with Company personnel from other departments, including Environmental Services, Corporate Services, Fossil Generation, Legal, Regulatory Planning, and Health and Services as needed. The Company also has appointed a designated Project Assurance Advisor to support and advise the project management team.

To promote efficient integration of the new equipment with current operations, the Company also has established a Plant Integration Team (PIT) that will be involved through the startup and commissioning process. The PIT was established early in the life of the Project to allow for plant operational input into the technical and functional requirements incorporated in the Project design, the operational design features, the anticipated operation of the new systems and the performance guarantees. During the construction phase, the PIT provides interface between me and plant operations and has the primary responsibility for developing operational maintenance procedures for the new equipment. The PIT also will participate in startup integration for commercial operation.

Q. Has the Company implemented policies and procedures to ensure proper management of the Crystal River Project and to control project costs?

A. Yes. The project is being implemented in accordance with the Generation and Transmission Construction Department's policies and procedures, which prescribe specific requirements for project management, quality assurance/quality control (QA/QC), schedule management, cost accounting and reporting, and other aspects of the project implementation. These policies and procedures reflect the collective experience and knowledge of the Company. They have been tested on other capital projects of this nature and reflect lessons learned from those projects. They also are consistent with best practices for capital project management in the industry.

Q. Are employees involved in the Crystal River Project trained in the Company's project management and cost control policies and procedures?

A. Yes, they are. The project management team for the Crystal River Project has been trained in these policies and procedures.

Q. Does the Company verify that the project management and cost control policies and procedures are followed?

A. Yes, it does. PEF uses internal audits to verify that its program management and oversight control are in place and being implemented.

Q. Has the Company implemented other mechanisms to ensure proper oversight and review of the Crystal River Project?

A. Yes. We have implemented several mechanisms to ensure proper oversight and review of the Crystal River Project. My project management team and I work closely with the Project Assurance Advisor to identify key project decisions and milestones to ensure that adequate documentation is prepared and maintained. Among other things, the project management team regularly prepares Project Cost Reports to 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 conduct a wide variety of meetings to maintain supervision of the project and to ensure that Company management remains fully informed. We conduct regularly scheduled, monthly meetings with the EPC contractor (EPCR) and primary FGD and SCR design and procurement contractor (B&W) to review construction progress and the remaining scope of work. Following those meetings, we hold regular monthly meetings with executive management to review the status of the project and its costs, as well as the administration of the various contracts. Executives from EPCR and B&W participate in these meeting to ensure that management expectations are communicated to the outside vendors as well as the project team.

The Company also reviews the feasibility of the Crystal River Project with senior management through the Company's Integrated Project Plan ("IPP") process, which has been established for gaining management approval for expenditures of

significant funds. The original IPP for the Crystal River Project was prepared in October 2007 in conjunction with the execution of the final EPC contract. Among other things, the IPP outlined the scope of the project, project costs, the Company's risk management strategy, and the economic evaluation discussed in the Integrated Clean Air Compliance Plan submitted to and approved by the Commission in last year's docket.

Q. Have there been any recent developments concerning the Clean Air Interstate Rule (CAIR)?

A. Yes. As discussed in the pre-filed testimony of Patricia Q. West, the U.S. Circuit Court of Appeals for the District of Columbia recently issued a decision vacating CAIR. At this date, the decision is not final and it is too early to determine the full impact of the Court's decision. PEF is continuing to implement its Commission-approved Integrated Clean Air Compliance Plan as the Company assesses the potential implications of the Court's decision. As Ms. West indicated, we will update the Commission on the status of the CAIR decision and PEF's implementation of its clean air compliance plan in future testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DALE WILTERDINK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 29, 2008

Q. Please state your name and business address.

A. My name is Dale W. Wilterdink. My business address is 15760 West Power Line Street, Crystal River, Florida, 34428.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida ("PEF") as Manager of Plant Construction Projects.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously submitted pre-filed direct testimony in this proceeding on August 4, 2008.

Q. Have your responsibilities changed since you previously submitted testimony in this proceeding?

A. No. They have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to update the Commission on the Crystal River Units 4 and 5 air quality control system project ("Crystal River Project") included in PEF's Integrated Clean Air Compliance Plan. I also will present PEF's current estimates of the costs that will be incurred in the 2009 for the Crystal River Project.

Q. Have PEF's plans for the Crystal River Project changed in light of the recent federal court decision vacating the Clean Air Interstate Rule (CAIR)?

A. Not at this time. As discussed in the pre-filed testimony of PEF witness Michael Kennedy, the decision vacating CAIR is not final because U.S. Circuit Court of Appeals for the District of Columbia ("D.C. Circuit") has not yet issued a mandate. Until that happens, CAIR is still in effect. For that reason, we are continuing forward with the Crystal River Project to ensure that PEF can meet CAIR's compliance deadlines in the event the Court revisits its vacatur. In addition, as further discussed in Mr. Kennedy's testimony, PEF is continuing to work with the Florida Department of Environmental Protection ("FDEP") in developing an overall plan to ensure compliance with other existing and foreseeable environmental requirements assuming the vacatur of CAIR becomes final.

Q. How far along is PEF in implementing the Crystal River Project?

A. The Crystal River Project remains on schedule to meet the in-service dates set forth in the Integrated Clean Air Compliance Plan approved by the Commission in

2007. Through August 2008, we have incurred or have committed to incur capital costs of approximately $838.8 million on the Project. This represents approximately 66.7 percent of the total projected costs of the Project, as presented in the Integrated Clean Air Compliance Plan approved by the Commission in Docket No. 070007-EI.

Q. What project milestones to you expect to achieve in 2009?

A. We currently expect to achieve several significant project milestones in 2009. In [redacted], we expect to place the Crystal River Unit 5 low NOx burners ("LNB") and selective catalytic ("SCR") system and the urea to ammonia hydrolyzer into service. Additionally, in [redacted], we expect to place the Unit 5 SCR and Flue Gas Desulfurization ("FGD" or "scrubber") system and chimney into service. In her pre-filed testimony, Ms. Cross explains the impact of placing these controls and associated equipment in-service on PEF's ECRC factors.

Q. What are PEF's projected 2009 expenditures for the Crystal River Project (Project 7.4)?

A. As shown in Form 42-4P in Exhibit No. __ (LC-3) to the testimony of Lori Cross, PEF currently is projecting to spend approximately $215.9 million in capital expenditures on the Crystal River Project in 2009. In addition to the finalization of the Unit 5 LNB/SCR and FGD projects, the scope of work for 2009 includes continued work on the Unit 4 FGD system, as well as associated equipment, such as limestone handling, dewatering, gypsum removal, coal pond liners, settling

ponds, make-up water system, storage tanks, piping, and electrical and control system.

Q. What measures is PEF implementing to ensure that the level of expenditures for the Crystal River Project is reasonable and prudent?

A. PEF will continue to implement the measures discussed in my prior testimony to ensure that costs incurred are reasonable and prudent. Among other things, we 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.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

J. MICHAEL KENNEDY

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 29, 2008

Q. Please state your name and business address.

A. My name is J. Michael Kennedy. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC, as a Principal Environmental Specialist.

Q. What are your job responsibilities?

A. I am responsible for analyzing and assessing emerging environmental regulatory and legislative issues for Progress Energy Florida ("PEF" or the "Company") and Progress Energy Carolinas. Prior to assuming my current position in August, 2005, I managed the environmental permitting and compliance activities in support of Florida Power Corporation's and then PEF's generating fleet. This included air construction permitting and "Title V" air operational permitting issues.

Q. Please summarize your educational background and professional experience.

A. I earned a B.S. degree in meteorology from Purdue University in 1978. Since obtaining my degree, I have had over 30 years experience in the air regulatory field. Before coming to work at Florida Power Corporation (now PEF), from January 1990 to June 1992, I was Senior Environmental Scientist at Indianapolis Power & Light Company, where my responsibilities included support of generating plants in the area of are permitting and compliance. From August 1986 to December 1989, I was the Permitting and Planning Manager for the Indianapolis Air Pollution Control Division. I managed the areas of air operating and construction permits, air quality modeling and planning, and regulatory development for Indianapolis/Marion County, Indiana. From June 1978 until July 1986, I worked as an Air Quality Planner for the Indianapolis Air Pollution Control Division. During that time, I helped develop the State Implementation Plan for compliance with the Clean Air Act Amendments of 1977.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a brief summary of the recent federal appellate court decision concerning the federal Clean Air Interstate Rule ("CAIR"). I also will summarize other existing and foreseeable air regulatory requirements that have or could have a bearing on PEF's Commission-approved Integrated Clean Air Compliance Plan.

Q. Were you involved in the development of PEF's Integrated Clean Air Compliance Plan?

A. Yes. I became involved in the development of PEF's compliance strategy even before CAIR was adopted in final form. I reviewed the draft, proposed, and final regulations to help the Company determine how many allowances it would be allocated so that the cost-effective control strategies could be developed. I also analyzed the Clean Air Mercury Rule ("CAMR") and the Clean Air Visibility Rule ("CAVR") as part of PEF's development of its integrated plan to achieve compliance with those rules as well as CAIR. In 2006 and 2007, I assisted in the preparation of the Integrated Clean Air Compliance Plan reports that PEF submitted to the Commission in Dockets 060007-EI and 070007-EI. Among other things, I prepared the discussion of CAIR and related air regulatory requirements, including CAMR, CAVR and Prevention of Significant Deterioration ("PSD") pre-construction permitting.

Q. Please summarize the recent decision concerning CAIR issued by the U.S. Circuit Court of Appeals for the District of Columbia ("D.C Circuit").

A. By way of background, the U.S. Environmental Protection Agency ("EPA") originally adopted CAIR to require 28 states and the District of Columbia to substantially reduce sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") emissions from power plants to prevent them from contributing to nonattainment of national ambient air quality standards in downwind states. Among other things, CAIR established a new "cap-and trade" program designed to achieve a 73 percent

reduction in SO_2 emissions and a 61 percent reduction in NOx emissions when fully implemented. In accordance with the federal rule, FDEP adopted its own rule to implement the CAIR cap-and-trade program and submitted the rule to EPA for approval as an amendment to Florida's State Implementation Plan ("SIP") under the federal Clean Air Act.

On July 11, 2008, the D.C. Circuit issued its decision in response to challenges to CAIR brought by several parties. *See, North Carolina v. EPA*, ___ F.3d ___, 2008 WL 2698180 (D.C. Cir. July 11, 2008). The D.C. Circuit's opinion addressed numerous issues, but the court's key point was that that each state must eliminate its significant contribution to non-attainment in another state. Based on that premise, the court invalidated the CAIR cap-and-trade program because, the court concluded, EPA had failed to demonstrate that they would avoid "significant contribution" to nonattainment of air quality in downwind states or otherwise avoid "interference with maintenance" of the standards. The court also found other flaws in the rule and, therefore, vacated the entire rule and remanded it back to EPA. The court did, however, uphold EPA's inclusion of the state of Florida within the scope of the CAIR. Thus, Florida likely will be included in any rule developed by EPA in response to the D.C. Circuit's decision.

Q. What is the current status of CAIR in light of the D.C. Circuit's decision?

A. The D.C. Circuit's vacatur of CAIR is not final because the court has not yet issued a mandate. The Petitioners and EPA originally had 45 days, or until August

25, 2008, to petition for rehearing of the decision. However, EPA requested and the D.C. Circuit has granted an extension of that deadline through September 24, 2008. Assuming one or more of the parties petitions for rehearing, the court will issue its mandate upon completion of any proceedings on the petition(s). The Petitioners and EPA also can seek review by the U.S. Supreme Court within 90 days after the later of the D.C. Circuit's decision or completion of proceedings on a petition for rehearing.

Q. What air regulatory requirements other than CAIR have a bearing on PEF's implementation of its Integrated Clean Air Compliance Program?

A. Notwithstanding the vacatur of CAIR, PEF must comply with the regulatory requirements established in CAVR. As implemented in FDEP's rules, CAVR has two primary components. First, certain industrial facilities that began operating between August 1962 and August 1977, including PEF's Crystal River Units 1 and 2 and Anclote Units 1 and 2, are required to install Best Available Retrofit Technology ("BART") no later than December 31, 2013, unless exempt based on the level of modeled visibility impairment. Second, if DEP determines implementation of BART has not achieved reasonable progress toward improving visibility in "Class I" areas, it may require emission units constructed before 1999 to install Reasonable Progress Control Technology ("RPCT") by December 31, 2017. This RPCT requirement could apply to Crystal River Units 4 and 5, as well as PEF's "BART-eligible" units. BART requirements potentially apply for NOx, SO_2 and particulate matter; whereas RPCT applies for SO_2.

Q. Could the vacatur of CAIR impact the CAVR component of PEF's Integrated Clean Air Compliance Plan?

A. Yes, it could. Under the current FDEP Rule 62-296.340(3)(a)2.b., Florida Administrative Code, BART-eligible sources that are subject to CAIR are not required to install BART for SO_2 or NOx. Based on this provision, PEF does not plan to install SO_2 or NOx controls on Crystal River Units 1 and 2 as part of its Integrated Clean Air Compliance Plan. Instead, PEF's plan focuses on Crystal River Units 4 and 5 because, as PEF's largest and newest coal-fired units, they provided the most cost-effective means of reducing SO_2 and NOx emissions.

If the vacatur of CAIR stands, the "CAIR satisfies BART" provision in FDEP's rule will no longer apply. For that reason, it is conceivable that Crystal River Units 1 and 2 could be subject to BART for SO_2 or NOx. For coal-fired units such as Crystal River Units 1 and 2, the rules include presumptive BART limits based on use of FGD for SO_2 and use of SCR for NOx. However, assuming the vacatur of CAIR stands, PEF believes that it would make more sense to go forward with the Crystal River Unit 4 and 5 SCR and FGD projects, rather than installing controls on Units 1 and 2. Our analyses indicate that this strategy of "grouping" Units 1 and 2 with Units 4 and 5 would provide at least as much, if not more, visibility benefits than installing controls on Units 1 and 2.

Q. What is the status of PEF's CAVR permitting efforts for the Crystal River units?

A. PEF submitted a BART permit application for Crystal River Units 1 and 2 in January 2007. In light of the CAIR vacatur, we are preparing a revised permit application to implement the "grouping" strategy I previously mentioned to take advantage of the near-complete Crystal River 4 and 5 controls. In preliminary discussions, FDEP officials have indicated that this strategy would be an acceptable means of complying with the BART and related requirements of DEP's rules. The FDEP officials also indicated that a final permit will likely be issued by the end of this year.

Q. Would the vacatur of CAIR impact PEF's plans for Anclote Units 1 and 2?

A. Anclote Units 1 and 2 also would potentially be subject to BART for SO_2 and NOx if the CAIR vacatur stands. The presumptive BART limits for these oil-fired units are based on the firing of one percent sulfur oil for SO_2 and installation of low NOx burners ("LNBs") for NOx. However, installation of LNBs would increase particulate matter ("PM") emissions such that additional PM controls could be required. For that reason, our revised permitting strategy will propose an alternative NOx control strategy that would not require additional PM controls.

Q. Are there any other, foreseeable air quality regulations or regulatory initiatives that could impact PEF's generating units in the future?

A. Yes. There are at least three foreseeable regulatory initiatives that could impact PEF's generating units in the relatively near future.

First, in March 2008, EPA adopted a new, more stringent national ambient air quality standard for ozone. *See* 73 Federal Register 16435 (March 12, 2008). Current monitoring data suggest that several areas in Florida, including Tampa Bay, Orlando and Jacksonville, may be designated "nonattainment" under the new standard. In accordance with EPA's rules, FDEP must submit its recommendation of nonattainment areas to EPA by March 2009. EPA then has one year, by March 2010, to issue final nonattainment areas designations. FDEP then has up to three years, by March 2013, to submit a SIP revision to the EPA showing how it would bring these areas into compliance. In developing the SIP revision, FDEP will evaluate the adequacy of currents regulations and programs, and determine if any new regulations or programs are necessary. Because NOx is an ozone precursor, FDEP could require installation and operation of NOx emission controls to ensure attainment of the new standard.

Second, as Ms. West noted in her pre-filed testimony and Exhibit No. __ (PQW-1) submitted on April 1, 2008, the D.C. Circuit recently vacated the federal CAMR regulation in *New Jersey v. EPA,* 517 F.3d 574 (D.C. Cir. 2008). As a result of the D.C. Circuit's decision, EPA may promulgate new Maximum Achievable Control Technology ("MACT") requirements for power plants. Although the EPA has not released a schedule for such rulemaking, FDEP has stated that it independently intends to adopt new rules establishing mercury emission standards for various industrial sources, including coal-fired power plants. FDEP is currently in the process of gathering data to support the rulemaking effort and FDEP officials have

stated that they intend to propose a rule for final adoption in the spring of 2009. As explained in the Integrated Clean Air Compliance Plan reports that PEF previously submitted to the Commission, the synergistic effect of SCR and FGD control systems results in substantial reductions in mercury emissions. Thus, depending on the final rules adopted by FDEP or EPA, the Crystal River 4 and 5 SCR and FGD systems could be a key component of PEF's mercury compliance strategy.

Finally, if the D.C. Circuit's vacatur of CAIR stands, EPA or the U.S. Congress will likely establish new rules or legislation to prevent upwind SO_2 and NOx emissions from contributing to nonattainment of air quality standards in down-wind states. Given the uncertainty surrounding CAIR, however, the timing of any such rules or legislation cannot be predicted at this time.

Q. What is the status of PEF's Integrated Clean Air Compliance Plan in light of the D.C. Circuit's CAIR decision?

A. Because the D.C. Circuit's decision vacating CAIR is not final, PEF is continuing forward with installation of the emission control components of its Integrated Clean Air Compliance Plan to ensure that the Company can meet CAIR's imminent compliance deadlines in the event the D.C. Circuit revisits the vacatur. Given our state of knowledge at this time, we believe this is a reasonable and prudent course of action. As I discussed previously, PEF also is continuing to work with FDEP in developing a cost-effective plan to meet CAVR and other

existing and foreseeable air regulatory requirements by taking advantage of the near-complete Crystal River 4 and 5 controls, rather than installing expensive controls on Units 1 and 2 or other PEF generating units, and implementing alternative NOx controls for Anclote Units 1 and 2. If this strategy is not approved, PEF will need to re-evaluate its current plans, assuming the D.C. Circuit's vacatur becomes final.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JOSEPH MCCALISTER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 4, 2008

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 410 South Wilmington Street, Raleigh, North Carolina 27601.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas (PEC) in the capacity of Director, Gas & Oil Trading.

Q. What are your responsibilities in that position?

A. I am responsible for the procurement of natural gas, fuel oil and emission allowances on behalf of PEC and Progress Energy Florida (PEF).

Q. Have you previously provided testimony before this Commission in connection with PEF's Environmental Cost Recovery Clause?

A. Yes. In last year's docket (No. 070007-EI), I presented testimony outlining PEF's overall approach to procuring emission allowances as part of its

Integrated Clean Air Compliance Plan and preparation for the compliance requirements of the Clean Air Interstate Rule (CAIR).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize PEF's actions to date related to its emission allowance procurement strategy as part of its Integrated Clean Air Compliance Strategy in preparation for the requirements under the CAIR.

Q. How does PEF determine how many emission allowances it needs to purchase?

A. As part of the fuel and generation forecasts, emission projections are generated. The forecasts are generated periodically and are based on input assumptions such as generation availability and capacity, planned generation outage schedules, purchased power contracts, fuel and emission price forecasts, planned environmental equipment installations and load projections. To determine if the Company needs to purchase emission allowances for compliance requirements in the current or in future time periods, PEF compares the forecasts of the emissions that will be generated to the number of emission allowances that PEF owns through allocations, purchases and accumulated inventory. In aggregate, the tons of emissions that PEF expected to generate based on the forecasts is greater than the number of allowances that PEF owns for the respective periods. As such, PEF projected the need to purchase allowances from the market in order to comply with the regulations.

Q. How did CAIR impact PEF's procurement activities for emission allowances?

A. The CAIR established an updated cap-and-trade system for sulfur dioxide (SO_2) and nitrogen oxides (NOx) and covered 28 eastern states and the District of Columbia. CAIR established modified SO_2 annual compliance requirements under Title IV of the Clean Air Act by requiring two (2.0) SO_2 allowances to be submitted per ton of SO_2 emissions beginning with 2010 annual compliance filings and 2.86 SO_2 allowances to be submitted per ton of SO_2 emissions starting with 2015 annual compliance filings. In addition, CAIR established new seasonal and annual emission compliance requirements for NOx. Beginning in 2009, CAIR required affected sources to complete a seasonal NOx emission allowance compliance submittal for the May 1 through September 30 time period and an annual NOx emission allowance compliance submittal for the January 1 through December 31 time period each year.

Q. What strategy has PEF pursued for procuring emission allowances to ensure compliance with CAIR?

A. PEF's overall procurement strategy for meeting emission allowance requirements is to buy allowances over time based on forecasted needs to comply with existing and future compliance requirements. PEF believes a procurement strategy of buying emission allowances over time is a reasonable and prudent approach to ensure compliance requirements are met and reduce price risk and volatility for customers. With the adoption of CAIR, this procurement approach was particularly prudent given PEF's forecasted needs,

market liquidity and the market price volatility associated with the new annual NOx allowances.

As part of its Integrated Clean Air Compliance Plan, PEF forecasted the need to purchase both seasonal and annual NOx emission allowances in order to comply with CAIR beginning with 2009 operations. For that reason, and consistent with its strategy, PEF has been purchasing seasonal and annual NOx allowances over time to gradually increase inventories to the levels necessary to achieve compliance. As of June 30, 2008 PEF had approximately $59.2 million in annual NOx emission allowance purchases in inventory, approximately $6.3 million in seasonal NOx emission allowance purchases in inventory and approximately $18 million in SO_2 emission allowance inventory.

Q. How do the Estimated/Actual purchases of emission allowances for the period January 2008 through December 2008 compare with PEF's original projections?

A. The revenue requirements on the inventory of SO_2 and NOx emission allowances are estimated to be $4,454,498 or 86% higher than originally projected. At the time of the last year's projection filing, prices for NOx allowances were highly volatile and unpredictable because the market for these allowances was for a new compliance obligation, trading was just beginning, and the allowance allocations to the applicable states and company accounts had not been made. As a result, there was a high degree of uncertainty related to the exact timing of NOx allowance purchases in the future. PEF applied an

approach for NOx allowance purchases, whereby inventory and rates included only purchases that had already been agreed to at the time of filing. NOx allowance purchases were projected in inventory balances only if there was an executed contract with a transaction that was expected to settle during the year. Subsequent to the filing, market activity increased and the EPA began making allocations of emission allowances. As PEF forecasted significant needs for annual NOx allowances and consistent with its strategy, PEF began making additional purchases of annual NOx allowances. As such, the variance is primarily attributable to the subsequent NOx allowances purchases that did not have executed contracts at the time of the previous projection filing.

Q. How does the average price that PEF paid for NOx allowances compare to market indicators?

A. The average price PEF paid for vintage 2009 NOx allowances that are included in inventory was approximately [redacted], which was lower than market indications at the time of my testimony last year, as well as recent market prices as of July 10, 2008. As I testified last year, as of July 27, 2007, vintage 2009 NOx emission allowances were being bid around $5,200/ton (what buyers were willing to pay) and offered at $6,200/ton (the price sellers wished to receive). At that same time, actual, observed published market trades ranged between $4,750/ton and $5,100/ton. As of June 30, 2008, vintage 2009 NOx allowances were trading at approximately $5,000/ton.

Q. Have there been any recent developments concerning CAIR?

A. Yes. As discussed in the pre-filed testimony of Patricia Q. West, the U.S. Circuit Court of Appeals for the District of Columbia recently issued a decision vacating CAIR. Although the decision is not final, PEF has stopped purchasing CAIR emission allowances in light of the market uncertainty created by the Court's decision.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

DANIEL L. RODERICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 29, 2008

Q. Please state your name and business address.

A. My name is Daniel L. Roderick. My business address is Crystal River Energy Complex, Site Administration 2C, 15760 West Power Line Street, Crystal River, Florida 34428.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida ("PEF" or the "Company") in the capacity of Vice President – Nuclear Projects & Construction. As Vice President – Nuclear Projects & Construction, I am responsible for the management and oversight of all large, capital nuclear projects for the Company. These include the Crystal River Unit 3 ("CR3") power uprate project, the CR3 steam generator replacement project scheduled for 2009, and the development, siting, engineering, and construction of two new nuclear generating facilities at the Company's Levy County site. Prior to assuming my current position, I served as the CR3 Director of Site Operations. In that capacity, I was responsible for the safe, efficient, and

reliable generation of electricity from the Company's CR3 nuclear plant. All plant functions, including the Plant General Manager, Engineering Manager, Training Manager, and Licensing, reported to me and were under my supervision.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor of Science and Master of Science degree in Industrial Engineering from the University of Arkansas and have completed the Nuclear Regulatory Commission (NRC) program for a Senior Reactor Operator License. I have been at CR3 since 1996, serving in my current position as Vice President Nuclear Projects and Construction and, prior to that position, Director of Site Operations, Plant General Manager, Engineering Manager, and Outage Manager, respectively. Prior to my employment with the Company, I was employed for twelve years with Entergy Corporation at its Arkansas Nuclear One plant in Russellville, Arkansas with responsibilities in Plant Operations and Engineering.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support PEF's request to recover, through the Environmental Cost Recovery Clause ("ECRC"), prudently incurred costs for its Crystal River Units 1 and 2 ("CR1&2") Thermal Discharge Compliance Project. The permanent solution associated with the CR1&2 thermal discharge limit is being undertaken in coordination with the CR3 Uprate project POD impacts as it makes more sense to consider the project as a whole from an engineering

perspective. I am responsible for the successful management of the Uprate project and, as such, this project falls under my umbrella of responsibility as well.

Q. Please describe PEF's CR1&2 Thermal Discharge Compliance Project.

A. In Docket No. 060162-EI, the Commission approved recovery of costs associated with installation and operation of leased Modular Cooling Towers to maintain compliance with the thermal discharge limit in the Florida Department of Environmental Protection ("FDEP") industrial wastewater discharge permit for Crystal River Units 1&2. See Order No. PSC-07-0722-FOF-EI (Sep. 5, 2007). Consistent with PEF's petition and the final order in Docket No. 060162, PEF has continued to evaluate the long term nature and extent of the issue associated with increased inlet water temperatures that triggered the need for additional cooling capacity to maintain compliance with the FDEP permit while minimizing derates of CR1&2.

Based on the on-going avoided derates experienced in 2006 (approximately 62,360 MWhs) and 2007 (approximately 180,500 MWhs), PEF believes the thermal discharge problem is a long-term issue that must be addressed. With this in mind, PEF asked Sargent & Lundy to study the issue and make a recommendation for what the optimal solution is for both the on-going environmental issue as well as the additional cooling that will be required as part of the CR3 Uprate project. The Project's study phase recommendation is to install a 12 cell circular cooling tower and expand the number of Helper Cooling

Tower ("HCT") cells. PEF is continuing to refine the exact final permanent solution based on on-going engineering analysis. The 2009 projection of costs are based on the most up-to-date estimate available at this time consistent with Sargent & Lundy's estimates.

Q. Please explain the basis for the Company's decision to install the new cooling capacity rather than continue with the Modular Cooling Towers.

A. The Sargent & Lundy Phase 1 report looked at what was more cost effective, continued operation of the Modular Cooling Towers, or some other more permanent kind of cooling solution. Based on the results of the Sargent & Lundy Phase 1 study based on the facts and circumstances known at the time of the Study it appears a permanent cooling solution makes more sense from both a technical and financial perspective. PEF is continuing to look at what the best solution is taking all variables into account.

Q. What activities does PEF anticipate undertaking for the CR1&2 Thermal Discharge Compliance Program in 2009?

A. The activities to be conducted in 2009 primarily include engineering, design and procurement of equipment (e.g., lift pumps, fabricated steel, dual flow screens, cooling towers, piping, valves, switchgear and storage facility). PEF also expects to incur project and construction management costs. This work will be done in conjunction with the installation of additional cooling capacity needed to

accommodate the CR3 uprate project. However, PEF only seeks ECRC recovery of the costs attributable to replacement of the Modular Cooling Towers.

Q. What environmental laws or regulations require implementation of the CR1&2 Thermal Discharge Compliance Project?

A. As recognized in Order No. PSC-07-0722-FOF-EI issued in Docket No. 060162-EI, the additional cooling capacity is required to maintain compliance with the thermal discharge limit in the CR1&2 industrial wastewater discharge permit whose effect was triggered by the unanticipated high inlet water temperatures, which were not fully analyzed until after PEF's last ratemaking proceeding in Docket No. 050078-EI.

Q. Has the Company projected the costs that it will incur for the CR1&2 Thermal Discharge Compliance Project?

A. Yes. PEF's preliminary cost estimates for the entire cooling project in 2009 is approximately $20 million. Of this $20 million, PEF preliminarily estimates approximately 58% ($11.6 million) is attributable to replacement of the leased Modular Cooling Towers. The remainder of the 2009 project costs will be attributable to the CR3 uprate project. The total cost of the project inclusive of costs attributable to the CR3 uprate project is approximately $103 million. PEF's preliminary estimate of the total cost associated with the long term solution to the CR1&2 thermal discharge compliance issue is approximately $60 million.

Q. What measures will PEF be implementing to ensure that costs incurred for the CR1&2 Thermal Discharge Compliance Project are reasonable and prudent?

A. The majority of the 2009 work will be contracted using the PEF competitive bid process. The competitive bid process obtains proposals from several potential contractors. The proposals are then evaluated and awarded based on technical merit and cost effectiveness.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

LORI CROSS

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 4, 2008

Q. Please state your name and business address.

A. My name is Lori Cross. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC, as Manager of Regulatory Planning Florida.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning, cost recovery and pricing functions for Progress Energy Florida, Inc. ("PEF"). These responsibilities include: cost of service analysis; regulatory financial reports; rate and tariff development and administration; analysis of state, federal and local regulations and their impact on PEF; planning, coordination and execution of general rate case proceedings as necessary. In this capacity, I am also responsible for the Environmental Cost

Recovery Clause (ECRC) Actual/Estimated filing, made as part of Docket No. 080007-EI.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science degree in Accounting from the University of South Florida. I began my employment with PEF (previously Florida Power Corporation) in 1983. During my 25 years with Florida Power Corporation and now Progress Energy Service Co. LLC., I have held a number of financial and accounting positions. In 2004, I became Manager, Regulatory Services for PEF.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, Progress Energy Florida's Estimated/Actual True-up costs associated with Environmental Compliance activities for the period January 2008 through December 2008.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit No. __ (LC-1), which consists of PSC Forms 42-1E through 42-8E, pages1 through 13; and
2. Exhibit No. __ (LC-2), which provides details of four capital projects by site.

These forms provide a summary and detail of the Estimated/Actual True-up O&M and Capital Environmental costs and revenue requirements for the period January 2008 through December 2008.

Q. What is the Estimated/Actual True-up amount for which PEF is requesting recovery for the period of January 2008 through December 2008?

A. The Estimated/Actual True-up amount for 2008 is an under-recovery, including interest, of $9,872,429 as shown in Exhibit No. __ (LC-1), Form 42-1E, Line 4. This amount will be added to the final true-up over-recovery of $5,562,717 for 2007 shown on Form 42-2E, Line 7-a., resulting in a net under-recovery of $4,309,712 as shown on Form 42-2E, Line 11. The detailed calculations supporting the estimated true-up for 2008 are contained in Forms 42-1E through 42-8E.

Q. Are any of the costs listed in Forms 42-1E through 42-8E attributable to Environmental Compliance projects that have not previously been approved by the Commission?

A. No, with the exception of the Greenhouse Gas Inventory and Reporting project, which is discussed and supported in the testimony of Ms. Patricia Q. West.

Q. How do the Estimated/Actual O&M expenditures for January 2008 through December 2008 compare with original projections?

A. Form 42-4E shows that total O&M project costs are projected to be $1,699,095 or 4% higher than originally projected. Following are variance explanations for

those O&M projects with significant variances. Individual project variances are provided on Form 42-4E.

O&M Project Variances:

1. **Transmission and Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention (Project #1) - O&M**

   Project revenue requirements are estimated to be $2,736,930 or 125% higher than previously projected. As discussed in the testimony of Donald R. Ennis, this variance is primarily attributable to an increase in the amount of subsurface contamination encountered during remediation of substations that was not evident during the original visual environmental inspections.

2. **Distribution System Environmental Investigation, Remediation, and Pollution Prevention (Project #2) - O&M**

   Project revenue requirements are estimated to be $427,507 or 3% higher than previously projected. As discussed in Mr. Ennis' testimony, this variance is primarily attributable to higher unit costs and the carryover of work from the 2007 work plan.

3. **Pipeline Integrity Management Program (Project #3) – O&M**

   Project revenue requirements are estimated to be $146,057 or 43% higher than previously projected. This variance is primarily attributable to work that was not completed from the 2007 workplan being carried over into 2008. This project is further discussed in Ms. West's testimony.

4. Above Ground Storage Tank Containment (Project #4.x) – O&M

Project revenue requirements are $368,303 higher than projected. This variance is primarily attributable to the rework performed at Turner Tank 8. This project is further discussed in Ms. West's testimony.

5. Emissions Allowances (Project #5) – O&M

Expenses for sulfur dioxide (SO_2) emission allowances are estimated to be $1,649,557 or 10% lower than originally projected. This variance is primarily being driven by lower projected tons of emissions. The decrease in tons is attributable to lower SO_2 content in fuel, as well as lower energy requirements than projected.

6. Phase II Cooling Water Intake (Project #6) – O&M

Project revenue requirements are estimated to be $38,128 or 26% lower than originally forecasted. This variance is primarily attributable to lower study and reporting costs. This project is further discussed in Ms. West's testimony.

7. CAIR/CAMR (Project #7.2) – O&M

Project revenue requirements are estimated to be $48,500 or 100% lower than originally projected due to software support costs not being incurred during 2008. This project is further discussed in Ms. West's testimony.

8. Arsenic Groundwater Standard (Project #8) – O&M

Project revenue requirements are estimated to be $77,669 or 100% lower than originally forecasted. This variance is due to the work being postponed until finalization of a compliance plan and schedule with FDEP. This project is further discussed in Ms. West's testimony.

9. Sea Turtle – Coastal Street Lighting (Project #9) – O&M

Project revenue requirements are estimated to be $173,289 or 62% lower than originally forecasted. This variance is primarily attributable to lower than anticipated costs of a lighting study to be conducted jointly with the University of Florida. This project is further discussed in Mr. Ennis' testimony.

10. Greenhouse Gas Inventory and Reporting (Project #12) – O&M

Project revenue requirements are estimated to be $7,440. These costs consist of fees paid to an outside consultant to develop an emissions quantification template in order to facilitate reporting to the Climate Registry.

Q. How do the Estimated/Actual Capital recoverable expenditures for January 2008 through December 2008 compare with PEF's original projections?

A. Total recoverable capital investments itemized on Form 42-6E, are projected to be $6,070,323 or 84% higher than originally projected. Below are variance explanations for those approved Capital Investment Projects with significant variances. Individual project variances are provided on Form 42-6E. Return on

Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided on Form 42-8E, pages 1 through 13.

Capital Investment Project Variances:

1. **Pipeline Integrity Management Program (Project #3.1) – Capital**

   Project revenue requirements are $65,608 or 14% higher than projected primarily due to the correction of the depreciation rate in May, resulting in an increase in jurisdictionalized depreciation expense of $63,462. This project is further discussed in Ms. West's testimony.

2. **Above Ground Storage Tank Containment (Project #4.x) – Capital**

   Project revenue requirements are $111,421 or 12% lower than projected due to the rework performed at Turner Tank 8. As a result of this rework, PEF has written-off approximately $368,303 in capital expenditures to O&M and is refunding to customers the associated $189,785 of previously recovered interest and return on investment. Excluding this one-time event, the project's revenue requirements are approximately $301,206 higher due to the increase in capital expenditures from the projection filing as upgrade work is being performed at two tanks at Turner that was not included in the projection. This project is further discussed in Ms. West's testimony.

3. **Emissions Allowances (Project #5) – Capital**

   The revenue requirements on the inventory of SO_2 and nitrogen oxide (NOx) emission allowances are estimated to be $4,454,498 or 86% higher than

originally projected. At the time of the projection filing, there was a high degree of uncertainty related to the timing and amount of NOx allowance purchases in the future. For that reason, PEF's projection filing only included a return on capital for purchases certain to occur during 2008 (i.e., if there was an executed contract with a transaction that was expected to settle during the year). The variance is primarily attributable to the return on incremental NOx allowances purchases that did not have executed contracts at the time of the projection filing. This project is discussed further in the testimony of Joseph McCallister.

4. CAIR/CAMR (Project #7.x) – Capital

Project revenue requirements are estimated to be $1,657,146 or 379% higher than originally projected. This variance is primarily attributable to two assets going into service during 2008 that were not included in the 2008 Projection. The first, the Access Road and Vehicle Barrier System (Project 7.4a) went into service in May 2008 and the second, the Low NOx Burner at Crystal River 4 (Project 7.4b) will be placed into service in December 2008.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

LORI CROSS

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 080007-EI

AUGUST 29, 2009

Q. Please state your name and business address.

A. My name is Lori Cross. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC, as Manager of Regulatory Planning Florida.

Q. Have you previously filed testimony before this Commission in connection with PEF's Environmental Cost Recovery Clause (ECRC)?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, Progress Energy Florida's ("PEF's") calculation of the revenue requirements and its ECRC factors for application on customer billings during the period January 2009 through December 2009. My testimony addresses the capital and operating and maintenance ("O&M") expenses associated with PEF's environmental compliance activities for the year 2009 and actions to date related to its emission allowance procurement strategy as part of its Integrated Clean Air Compliance Strategy in preparation for the requirements of the Clean Air Interstate Rule ("CAIR").

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit No. __ (LC-3), which consists of PSC Forms 42-1P through 42-7P; and
2. Exhibit No. __ (LC-4), which provides details of four capital projects by site.

Q. What is the total recoverable revenue requirement relating to the projection period January 2009 through December 2009?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is $137,323,719 as shown on Form 42-1P, Line 5 of Exhibit No. __ (LC-3).

Q. What is the total true-up to be applied in the period January 2009 through December 2009?

A. The total true-up applicable for this period is an under-recovery of $4,316,060. This consists of the final true-up of over-recovery of $5,556,369 for the period from January 2007 through December 2007 and an estimated true-up under-recovery of $9,872,429 for the current period of January 2008 through December 2008. The detailed calculation supporting the estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (LC-1) filed with the Commission on August 4, 2008.

Q. Are all the costs listed in Forms 42-1P through 42-7P attributable to Environmental Compliance projects previously approved by the Commission?

A. Yes, with the exception of the Crystal River 1&2 Thermal Discharge Compliance Project discussed below and the Greenhouse Gas Inventory and Reporting Project discussed in the pre-filed testimony of Patricia Q. West submitted on August 4, 2008. PEF's 2009 ECRC projections include the following projects that have been previously approved by the Commission:

The CAIR and the Clean Air Mercury Rule ("CAMR") Program (No. 7) was previously approved as an ECRC recoverable project in Order No. PSC-05-1251-FOF-EI. The Commission approved PEF's Integrated Clean Air Compliance Plan for complying with CAIR, CAMR, the Clean Air Visibility Rule ("CAVR") and related regulatory requirements in Order No. PSC-07-0922-FOF-EI.

The Substation and Distribution System O&M programs (Nos. 1 and 2) were previously approved by the Commission in Order No. PSC-02-1735-FOF-EI.

The Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4) were previously approved in Order No. PSC-03-1348-FOF-EI.

The recovery of SO_2 Emission Allowances (No. 5) was previously approved in Order No. PSC-95-0450-FOF-EI; however, the costs were moved to the ECRC Docket from the Fuel Docket beginning January 1, 2004 at the request of Staff to be consistent with the other Florida IOUs.

The Phase II Cooling Water Intake 316(b) Program (No. 6) was previously approved in Order No. PSC-04-0990-PAA-EI.

The Sea Turtle Lighting Program (No. 9), the Arsenic Groundwater Standard Program (No. 8), and the Underground Storage Tanks Program (No. 10) were previously approved in Order No. PSC-05-1251-FOF-EI.

The Modular Cooling Tower Program (No. 11) was previously approved by Commission in Order No. PSC-07-0722-FOF-EI.

Q. Please describe the CR1&2 Thermal Discharge Compliance Project.

A. In Order No. PSC-07-0722-FOF-EI, the Commission approved recovery of costs associated with installation and operation of leased Modular Cooling Towers ("MCTs") to maintain compliance with thermal discharge limit in the Florida Department of Environmental Protection ("FDEP") industrial wastewater discharge permit for Crystal River Units 1 and 2 ("CR1&2"). Consistent with PEF's petition and the final order approving the MCT Project, PEF has continued to evaluate the long term nature and extent of the issue associated with increased inlet water temperatures that triggered the need for additional cooling capacity to maintain compliance with the FDEP permit while minimizing derates of CR1&2. Through the CR1&2 Thermal Discharge Compliance Project, PEF will replace the MCTs with a more permanent compliance solution. Further detail regarding the compliance project is provided in the testimony of PEF witness Daniel Roderick.

Q. Are you familiar with the requirements that environmental costs must meet to be eligible for recovery through the ECRC?

A. Yes. The general requirements are follows:

- All expenditures must have been prudently incurred after April 13, 1993;
- All activities must be legally required to comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the company's last test year on which rates are based; and
- None of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

Q. Does the CR1&2 Thermal Discharge Compliance Project qualify for cost recovery under these criteria?

A. Yes. The project is being implemented in response to the environmental requirements which whose effect was triggered after the minimum filing requirements ("MFRs") were submitted in PEF's most recent ratemaking proceeding (Docket No. 050078-EI). As the Commission found in Order PSC-07-0722-FOF-EI issued in Docket No. 060162-EI, no costs for the additional cooling capacity needed to maintain compliance with the FDEP thermal discharge permit limits were included in the MFRs that PEF filed in its most recent ratemaking proceeding. Therefore, the costs are not recovered in base rates. Likewise, none of the costs of this program are being recovered through any other cost recovery mechanism.

Q. Have there been any recent developments concerning CAIR?

A. Yes. As discussed in the testimony of other PEF witnesses, the U.S. Circuit Court of Appeals for the District of Columbia recently issued a decision vacating CAIR. As explained by PEF witness Michael Kennedy, the Court's decision is not yet final, but PEF is working with state and federal agencies, as well as conducting internal analyses, to determine the appropriate course of action once the D.C. Circuit's decision becomes final and its full implications are known. As Mr. Kennedy and PEF witness Dale Wilterdink explain, PEF is continuing to implement the Crystal River emission control components of its Commission-approved Integrated Clean Air Compliance Plan as PEF assesses the potential implications of the Court's decision. PEF is continuing with plans to place in service the following plant assets in 2009: the Selective Catalytic Reduction system at Crystal River Unit 5 ("CR5"), the Urea to Amonia system, the Flue Gas Desulfurization at CR5, and Common Items. The revenue requirement of placing these items into service, including depreciation and property tax expense, is approximately $35 million, as reflected on Form 42-4P, page 9, of Exhibit No. __ (LC-3).

Q. Has the D.C. Circuit's decision vacating CAIR affected PEF's projected emission allowance costs?

A. Yes. As discussed in the pre-filed testimony of Joseph McCallister submitted on August 4, 2008, PEF has suspended further purchases of annual and seasonal nitrogen oxide ("NOx") allowances in light of the D.C. Circuit's decision. Until

the Court's decision is final, however, CAIR remains in effect. For that reason, we are assuming that PEF will need to use NOx allowances out of inventory in order to comply with CAIR in 2009. Additionally, PEF has assumed purchases to cover its short position in 2009 using the cost of annual NOx allowances on the day before the vacatur decision was issued. The costs of those NOx allowances are included in the projections provided in Form 42-4P, page 5, of Exhibit No. __ (LC-3).

Regardless of the CAIR vacatur, PEF will still be subject to the sulfur dioxide ("SO_2") allowance program under Title IV of the Clean Air Act. Thus, the projections provided in Form 42-4P, page 5, of Exhibit No. __ (LC-3) include SO_2 allowance costs.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2009?

A. Yes. Form 42-2P contained in Exhibit No. __ (LC-3) summarizes the recoverable O&M cost estimates for these projects in the amount of $90,880,829.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2009?

A. Yes. Form 42-3P contained in Exhibit No. __(LC-3), summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 14, shows

the calculations of these costs that result in recoverable jurisdictional capital costs of $42,028,028.

Q. Have you prepared schedules providing the description and progress reports for all environmental compliance activities and projects?

A. Yes. Form 42-5P, pages 1 through 11, contained in Exhibit No. __ (LC-3) provides each project description and progress, as well as the projected recoverable cost estimates.

Q. What is the total projected jurisdictional costs for environmental compliance activities in the year 2009?

A. The total jurisdictional capital and O&M costs of $137,323,719 to be recovered through the ECRC, are calculated on Form 42-1P, contained in Exhibit No. __ (LC-3).

Q. Please describe how the proposed ECRC factors were developed.

A. The ECRC factors were calculated as shown on Forms 42-6P and 42-7P contained in Exhibit No. __ (LC-3). The demand allocation factors were calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate class. The energy allocation factors were calculated by determining the percentage each rate class contributes to total kilowatt-hour sales and then adjusted for losses for each rate class. This

information was obtained from PEF's July 2007 load research study. Form 42-7P presents the calculation of the proposed ECRC billing factors by rate class.

Q. What are PEF's proposed 2009 ECRC billing factors by the various rate classes and delivery voltages?

A. The computation of PEF's proposed ECRC factors for customer billings in 2009 is shown on Form 42-7P, contained in Exhibit No. __(LC-3). In summary, these factors are as follows:

RATE CLASS	ECRC FACTORS
Residential	0.368 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.343 cents/kWh
@ Primary Voltage	0.340cents/kWh
@ Transmission Voltage	0.336 cents/kWh
General Service 100% Load Factor	0.291cents/kWh
General Service Demand	
@ Secondary Voltage	0.307cents/kWh
@ Primary Voltage	0.304 cents/kWh
@ Transmission Voltage	0.301 cents/kWh
Curtailable	
@ Secondary Voltage	0.287 cents/kWh
@ Primary Voltage	0.284 cents/kWh
@ Transmission Voltage	0.281 cents/kWh

Interruptible	
@ Secondary Voltage	0.296 cents/kWh
@ Primary Voltage	0.293 cents/kWh
@ Transmission Voltage	0.290 cents/kWh
Lighting	0.252 cents/kWh

Q. When is PEF requesting that the proposed ECRC billing factors be made effective?

A. PEF is requesting that its proposed ECRC billing factors be made effective with the first bill group for January 2009 and continue through the last bill group for December 2009.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average environmental billing factor of 0.338 cents per kWh which includes projected capital and O&M revenue requirements of $137,224,917 associated with a total of 12 environmental projects and a true-up under-recovery provision of $4,316,060. My testimony also demonstrates that the projected environmental expenditures for 2009 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
FILED: 04/02/08

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

Q. Please state your name, address, occupation and employer.

A. My name is Howard T. Bryant. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") in the position of Manager, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position, I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on ECRC activities since 2001 as well as conservation and load management activities, DSM goals setting, DSM plan approval dockets and other ECCR dockets since 1993.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present, for Commission review and approval, the actual true-up amount for the ECRC and the calculations associated with the environmental compliance activities for the January 2007 through December 2007 period.

Q. Did you prepare any exhibits in support of your testimony?

A. Yes. Exhibit No. _____ (HTB-1) consists of eight forms prepared under my direction and supervision.

- Form 42-1A, Document No. 1, Final true-up for the January 2007 through December 2007 period;
- Form 42-2A, Document No. 2, provides the detailed calculation of the actual true-up for the period;
- Form 42-3A, Document No. 3, provides details to the calculation of the interest provision for the period;
- Form 42-4A, Document No. 4, reflects the calculation of variances between actual and actual/estimated costs for O&M activities;
- Form 42-5A, Document No. 5, provides a summary of actual monthly O&M activity costs for the period;
- Form 42-6A, Document No. 6, provides details of the calculation of variances between actual and actual/estimated costs for capital investment projects;
- Form 42-7A, Document No. 7, presents a summary of actual monthly costs for capital investment projects for the period;
- Form 42-8A, Document No. 8, pages 1 through 26, consist of the calculation of depreciation expenses and return on capital investment for each project that is being recovered through the ECRC, and page 26 calculates the net expenses associated with maintaining an SO_2 allowance inventory.

Q. What is the source of the data presented by way of your testimony or exhibits in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. What is the actual true-up amount Tampa Electric is requesting for the January 2007 through December 2007 period?

A. Tampa Electric has calculated and is requesting approval of an over-recovery of $22,089,826 as the actual true-up amount for the January 2007 through December 2007 period.

Q. What is the adjusted net true-up amount Tampa Electric is requesting for the January 2007 through December 2007 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/(recovered) in the 2009 projection period?

A. Tampa Electric has calculated an over-recovery of

$12,465,653 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2007 through December 2007 period. This adjusted net true-up amount is the difference between the actual over-recovery and the actual/estimated over-recovery for the January 2007 through December 2007 period as depicted on Form 42-1A. The actual true-up amount for the January 2007 through December 2007 period is an over-recovery of $22,089,826 as compared to the $9,624,173 actual/estimated over-recovery amount approved in Commission Order No. PSC-07-0922-FOF-EI issued November 16, 2007.

Q. Are all costs listed in Forms 42-4A through 42-8A attributable to environmental compliance projects approved by the Commission?

A. All costs listed in Forms 42-4A through 42-8A for which Tampa Electric is seeking recovery are attributable to environmental compliance projects approved by the Commission. However, Form 42-8A, pages 20 - 22, provides expenditures associated with Big Bend Units 1-3 Selective Catalytic Reduction ("SCR") projects and are only included at this time for identification and tracking purposes. Recovery of these expenditures is not included in the 2007 ECRC True-Up. Consistent with the

Commission's decisions in Docket Nos. 980693-EI, 040007-EI, 040750-EI and 041376-EI, the company will not seek recovery of the SCR project costs associated with these Commission approved environmental compliance projects until each project is placed in-service. Big Bend Unit 4 SCR was approved in Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI and went in-service May 2007. Big Bend Units 1-3 SCRs were approved in Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI and are projected to be in-service in May 2010, May 2009 and April 2008, respectively.

Q. Did Tampa Electric include costs in its 2007 final ECRC true-up filing for any environmental projects that were not anticipated and included in its 2007 factors?

A. No.

Q. How did actual expenditures for the January 2007 through December 2007 period compare with Tampa Electric's actual/estimated projections as presented in previous testimony and exhibits?

A. As shown on Form 42-4A, total O&M activities costs were $12,133,973 or 18.1 percent lower than actual/estimated

projections. Form 42-6A shows the total capital investment costs were $44,759 or 0.2 percent lower than actual/estimated projections. O&M and capital investment projects with material variances from the 2007 Actual/Estimated True-Up filing are explained below.

O&M Project Variances

- **SO_2 Emissions Allowances:** The SO_2 Emission Allowances project variance was $11,360,650 or 14.3 percent less than projected. The variance was due to higher market prices for allowances sold than projected as well as more allowances sold than originally projected.
- **Big Bend Units 1&2 FGD:** The Big Bend Units 1&2 FGD project variance was $525,704 or 9.6 percent less than projected due to the coordination of maintenance with scheduled outages creating a delay in expenditures as well as lower moisture penalties due to improved gypsum quality.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance was $33,977 or 11.0 percent greater than projected due to the unanticipated coal pipe maintenance on Big Bend Unit 1.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance was $49,840 or 10.2 percent less than projected as a result of lower overall

activity due to planned outages.

- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance was $18,533 or 71.0 percent higher than projected due to the effort of the contractor to complete the study report earlier than the original delivery date.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance was $12,693 or 21.3 percent greater than originally projected due to increased demineralized water costs due to the failure of the decarbonator in the water treatment system. A replacement decarbonator has been received and will be installed during the planned outage in April 2008.
- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance was $4,946 or 7.1 percent greater than originally projected due to the unanticipated increase in ammonia consumption.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance was $42,586 or 19.4 percent greater than projected due to higher than anticipated testing and tuning costs.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project incurred $4,586 in expenses that was not originally projected due to minor repairs made to the secondary air damper drive as well as several coal pipes.

- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance was $8,365 or 55.8 percent less than projected due to the timing of equipment procurement and outages causing a delay of the in-service date.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project incurred $23,995 in expenses that was not originally projected due to the inspection and repair of the classifier vanes.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study was $55,344 or 13.9 percent less than projected due to the rule remand, necessitating a new strategy.
- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard program variance was $42,270 or 80.5 percent less than projected due to FDEP's late approval of the studies, thereby reducing the number of samples projected for 2007.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance was $165,505 or 21.8 percent less than projected due to the lower than anticipated consumption of ammonia.

Capital Investment Project Variances

- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance was $8,528 or 6.4 percent less than projected due to timing of equipment procurement and

outages causing a delay of the in-service date.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

Q. Please state your name, address, occupation and employer.

A. My name is Howard T. Bryant. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") in the position of Manager, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2008 through December 2008 estimated true-up amount to be refunded or recovered through the ECRC during January 2009 through December 2009. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2008, based on six months of actual data and six months of estimated data. This information will be used to determine the environmental cost recovery factors for January 2009 through December 2009.

Q. Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2008 through December 2008?

A. Yes. Exhibit No. _____ (HTB-2), containing eight documents, was prepared under my direction and supervision. It includes Forms 42-1E through 42-8E which show the current period estimated true-up amount to be used in calculating the cost recovery factors for January 2009 through December 2009.

Q. What has Tampa Electric calculated as the estimated true-up for the current period to be applied to the January 2009 through December 2009 ECRC factors?

A. The estimated true-up applicable for the current period, January 2008 through December 2008, is an under-recovery of $7,747,093. A detailed calculation supporting the estimated true-up is shown on Forms 42-1E through 42-8E of my exhibit.

Q. Is Tampa Electric including costs in this estimated true-up filing for any environmental projects that were not anticipated and included in its 2008 factors?

A. No.

Q. What depreciation rates were utilized for the capital projects contained in the 2008 Actual/Estimated True-Up?

A. Tampa Electric utilized the depreciation rates approved in Order No. PSC-08-0014-PAA-EI issued on January 4, 2008 in Docket No. 070284-EI.

Q. How did the actual/estimated project expenditures for January 2008 through December 2008 period compare with the company's original projection?

A. As shown on Form 42-4E, total O&M activities were $8,741,693 more than projected costs. Total capital expenditures itemized on Form 42-6E, were $1,320,210 lower than originally projected. O&M and capital investment projects with material variances are explained below.

O&M Project Variances

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance is estimated to be $401,216 or 10.9 percent lower than originally projected due to a lower

cost of consumables for gypsum production as well as a decrease in maintenance costs.

- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $10,647,829 or 36.2 percent higher than projected. The variance is due to the increase in the number of allowances sold in 2007 that were originally projected to be sold in 2008.
- **Big Bend Units 1 and 2 Flue Gas Desulfurization:** The Big Bend Unit 1 and 2 Flue Gas Desulfurization project variance is estimated to be $905,845 or 12.5 percent less than originally projected due to the re-allocation of 2008 maintenance activities with the scheduled outages for 2009.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is estimated to be $162,435 or 46.4 percent greater than originally projected due to unanticipated inspections for boiler tube degradation stemming from NO_x abatement measures, as well as burner modifications.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance is estimated to be $18,333 or 28.2 percent lower than originally projected due to a unit outage during the second quarter of 2008.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance is estimated to be

$26,005 or 52.0 percent higher than originally projected. The variance is due to the need for additional data collection than originally planned.

- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance is estimated to be $38,068 or 54.4 percent higher than originally projected due to the increase in price and consumption of ammonia.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is estimated to be $17,024 or 34.0 percent lower than originally projected due to less maintenance activity than anticipated.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $45,000 or 60.0 percent less than originally projected due to the delay of the in-service date for the Pre-SCR capital project.
- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is estimated to be $63,812 or 85.1 percent less than originally projected due to the delay of the in-service date for the Pre-SCR capital project.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is estimated to be $25,605 or 17.1 percent less than projected. The variance is due to the decrease in contractor costs to complete the impingement study reports.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $41,651 or 73.1 percent more than projected. The Florida Department of Environmental Protection requested to extend the data collection period, therefore requiring additional testing.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $278,964 or 17.3 percent less than originally projected due to a decrease in the usage of ammonia.
- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is estimated to be $406,900 or 25.3 percent less than originally projected due to the delay of commercial operation.

Capital Investment Project Variances

- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is estimated to be $73,909 or 8.5 percent less than the original projection due to the delay of the neural network portion of the project.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $81,480 or 18.6 percent less than the original projection due to the deferment of 2008 projected activities and associated

costs to 2009. The deferment resulted from a later completion of the unit outage than originally planned.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is estimated to be $3,346,470 or 38.1 percent less than the original projection due to turbine rotor repair that caused the delay in commercial operation.
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $2,282,312 or 37.3 percent more than originally projected due to an inadvertent calculation error found in the formula for the amount of average return on investment for the months of January through May 2008 in the 2008 Projection Filing.
- **Clean Air Mercury Rule:** The Clean Air Mercury Rule project variance is estimated to be $48,934 or 41.0 percent less than originally projected due to the decrease in scope of the project stemming from the February 8, 2008 Circuit Court decision to vacate the Clean Air Mercury Rule. As a result, EPA is evaluating the court's decision and its impacts.
- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $3,422 or 37.3 percent more than originally projected. The variance is due to the sale of allowances in 2007 than were originally projected for 2008.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
FILED: AUGUST 29, 2008

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

Q. Please state your name, address, occupation and employer.

A. My name is Howard T. Bryant. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present, for Commission review and approval, both the calculation of the revenue requirements and the projected ECRC factors for the period of January 2009 through December 2009. In support of the projected ECRC factors, my testimony identifies the capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for the year 2009. Finally, my testimony addresses the projected ECRC factors that would become effective in May 2009 based on the company's rate design modification proposed in Docket No. 080317-EI.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2009 through December 2009?

A. Yes. Exhibit No. ___ (HTB-3), containing eight documents, was prepared under my direction and supervision. Document Nos. 1 through 7 contain Forms 42-1P through 42-7P, which show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2009. Document No. 8, consisting of two pages, supports the proposed ECRC factors allocated on a 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD") basis. The proposed methodology is described in the direct testimony of William R. Ashburn submitted in Docket No. 080317-EI.

Q. Are you requesting Commission approval of the projected environmental cost recovery factors for the company's various rate schedules?

A. Yes. The ECRC factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (HTB-3), Document No. 7, on Form 42-7P. These annualized factors are expected to apply for the period January through

April 2009. The revised factors provided in Document No. 9 are based on Tampa Electric's proposed rate design modifications found in Docket No 080317-EI. The company is requesting an effective date of May 2009 for these revised factors, coincident with the effective date of base rate modifications proposed in the above referenced docket.

Q. How will the proposed ECRC factors be impacted if the implementation date of the base rate adjustment is different from May 1, 2009?

A. The proposed ECRC factors starting January 1, 2009 are annualized factors. Therefore, those factors would remain in effect until the Commission approves the proposed changes submitted as part of Docket No. 080317-EI.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2009 through December 2009?

A. The net true-up applicable for this period is an over-recovery of $4,718,560. This consists of the final true-up over-recovery of $12,465,653 for the period of January

2007 through December 2007 and an estimated true-up under-recovery of $7,747,093 for the current period of January 2008 through December 2008. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-8E of Exhibit No. ___ (HTB-2) filed with the Commission on August 4, 2008.

Q. What is the major contributing factor that has created the net over-recovery to be applied to the company's ECRC rates for the period January 2009 through December 2009?

A. The major contributing factor that has created the net over-recovery was the sale of surplus SO_2 emission allowances that were originally projected to occur in 2008 but instead occurred during 2007.

Q. Does Tampa Electric anticipate the sale of surplus SO_2 allowances during 2009?

A. Yes. The company anticipates the sale of approximately $13 million of surplus SO_2 allowances during 2009. The revenues from the allowance sales have an immediate, direct benefit to Tampa Electric customers since they offset environmental expenses. Additional details associated with the 2009 sales are provided by Tampa

Electric Witness, Paul L. Carpinone.

Q. Will Tampa Electric propose any new environmental compliance projects for ECRC cost recovery for the period from January 2009 through December 2009?

A. Tampa Electric anticipates proposing a Greenhouse Gas ("GHG") Reduction program to initiate data collection and reporting of GHG emissions as part of The Climate Registry as required by House Bill 7135. Presently, the Florida Department of Environmental Protection is reviewing the bill. Once the review is completed, it is anticipated rulemaking will begin and an eventual start date determined. At that time, Tampa Electric will file for recovery of the GHG program and outline more definitive program details and costs to comply with the new rule.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2009?

A. Tampa Electric proposes to include for ECRC recovery the 25 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2009. These projects are:

1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) Big Bend Unit 4 Continuous Emissions Monitors
4) Big Bend Fuel Oil Tank 1 Upgrade
5) Big Bend Fuel Oil Tank 2 Upgrade
6) Phillips Tank No. 1 Upgrade
7) Phillips Tank No. 4 Upgrade
8) Big Bend Unit 1 Classifier Replacement
9) Big Bend Unit 2 Classifier Replacement
10) Big Bend Section 114 Mercury Testing Platform
11) Big Bend Units 1 and 2 FGD
12) Big Bend FGD Optimization and Utilization
13) Big Bend NO_x Emissions Reduction
14) Big Bend Particulate Matter ("PM") Minimization and Monitoring
15) Polk NO_x Emissions Reduction
16) Big Bend Unit 4 SOFA
17) Big Bend Unit 1 Pre-SCR
18) Big Bend Unit 2 Pre-SCR
19) Big Bend Unit 3 Pre-SCR
20) Big Bend Unit 2 SCR
21) Big Bend Unit 3 SCR
22) Big Bend Unit 4 SCR
23) Big Bend FGD Reliability

24) Clean Air Mercury Rule

25) SO_2 Emission Allowances

Some of these projects will be described in more detail by Tampa Electric Witness, Paul L. Carpinone.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2009?

A. Yes. Form 42-3P contained in Exhibit No. ___ (HTB-3) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 26, provides the calculations of the costs, which result in recoverable jurisdictional capital costs of $44,275,332.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2009?

A. Tampa Electric proposes to include for ECRC recovery the 19 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2009. These projects are:

1) Big Bend Unit 3 FGD Integration

2) Big Bend Units 1 and 2 Flue Gas Conditioning

3) SO_2 Emissions Allowances

4) Big Bend Units 1 and 2 FGD

5) Big Bend PM Minimization and Monitoring

6) Big Bend NO_x Emissions Reduction

7) NPDES Annual Surveillance Fees

8) Gannon Thermal Discharge Study

9) Polk NO_x Emissions Reduction

10) Bayside SCR and Ammonia

11) Big Bend Unit 4 SOFA

12) Big Bend Unit 1 Pre-SCR

13) Big Bend Unit 2 Pre-SCR

14) Big Bend Unit 3 Pre-SCR

15) Clean Water Act Section 316(b) Phase II Study

16) Arsenic Groundwater Standard Program

17) Big Bend Unit 4 SCR

18) Big Bend Unit 3 SCR

19) Big Bend Unit 2 SCR

Some of these projects will be described in more detail by Tampa Electric Witness, Paul L. Carpinone.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2009?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3)

summarizes the recoverable jurisdictional O&M costs for these projects which total $5,593,806 for 2009.

Q. Do you have a schedule providing the description and progress reports for all environmental compliance activities and projects?

A. Yes. Project descriptions and progress reports, as well as the projected recoverable cost estimates, are provided in Form 42-5P, pages 1 through 31.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2009?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $49,869,138.

Q. How were environmental cost recovery factors calculated?

A. The environmental cost recovery factors were calculated as shown on Schedules 42-6P and 42-7P. The demand allocation factors were calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate

class. The energy allocation factors were determined by calculating the percentage that each rate class contributes to total MWh sales and then adjusted for losses for each rate class. This information was based on applying historical rate class load research to the 2009 projected forecast of system demand and energy. Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

Q. What are the ECRC billing factors by rate class for the period of January through December 2009 which Tampa Electric is seeking approval?

A. The computation of the billing factors by metering voltage level is shown in Exhibit No. ___ (HTB-3) Document No. 7, Form 42-7P. In summary, the January through April 2009 proposed ECRC billing factors are as follows:

Rate Class	**Factor at Secondary Voltage (¢/kWh)**
RS, RST Secondary	0.227
GS, GST, TS Secondary	0.227
GSD, GSDT Secondary	0.226

Primary	0.224
Transmission	0.222
GSLD, GSLDT, SBF	
Secondary	0.225
Primary	0.222
Transmission	0.220
IS1, IST1, SBI1, IS3, IST3, SBI3	
Secondary	0.222
Primary	0.219
Transmission	0.217
SL, OL Secondary	0.224
Average Factor	0.226

Q. Please describe the changes to the 2009 ECRC factors related to Tampa Electric's proposed rate design submitted in Docket No. 080317-EI.

A. As described in the direct testimony of William R. Ashburn filed in Docket No. 080317-EI on August 11, 2008, Tampa Electric proposes to combine all present demand rate schedules, which consist of General Service - Demand ("GSD"), General Service - Large Demand ("GSLD"), and Interruptible Service ("IS") into one new proposed GSD rate schedule. Additionally, the allocation of production demand costs according to the 12 CP and 1/13th

AD methodology, where 1/13th or approximately eight percent of the demand costs is allocated on an energy basis, has been modified to 12 CP and 25 percent AD to better reflect cost causation, as shown in the company's 2009 Cost of Service Study. The proposed rate class allocations and ECRC factors for these changes are shown in Document No. 8 of Exhibit No. ___ (HTB-3). In summary, the May through December 2009 proposed ECRC billing factors are as follows:

Rate Class		Factor at Secondary Voltage (¢/kWh)
RS		0.223
GS, TS		0.225
GSD, SBF		
	Secondary	0.229
	Primary	0.227
	Transmission	0.224
LS1		0.238
Average Factor		0.226

Q. When does Tampa Electric propose to begin applying these environmental cost recovery credits?

A. The environmental cost recovery credits will be effective

concurrent with the first billing cycle for January 2009.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2009 through December 2009 consistent with criteria established for ECRC recovery in Order No. PSC-94-0044-FOF-EI?

A. Yes. The costs for which ECRC treatment is requested meet the following criteria:

1. Such costs were prudently incurred after April 13, 1993;
2. The activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective or whose effect was triggered after the company's last test year upon which rates are based; and
3. Such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Please summarize your testimony.

A. My testimony supports the approval of a final average environmental billing factor credit of 0.226 cents per kWh which includes projected capital and O&M revenue requirements of $49,869,138 associated with a total of

31 environmental projects and a true-up over-recovery provision of $4,718,560 primarily driven by the timing of SO_2 allowance sales. My testimony also explains that the projected environmental expenditures for 2009 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007
FILED: 8/29/2008

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL L. CARPINONE

Q. Please state your name, address, occupation and employer.

A. My name is Paul L. Carpinone. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental Health & Safety in the Environmental Health and Safety Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Water Resources Engineering Technology from the Pennsylvania State University in 1978. I have been a Registered Professional Engineer in the State of Florida and Pennsylvania since 1984. Prior to joining Tampa Electric I worked for Seminole Electric Cooperative as a Civil Engineer in various positions and in environmental consulting. In February 1988, I joined Tampa Electric as a Principal Engineer, and I have primarily worked in the

area of Environmental Health and Safety. In 2006, I became Director, Environmental Health and Safety. My responsibilities include the development and administration of the company's environmental, health and safety policies and goals. I am also responsible for ensuring resources, procedures and programs meet or exceed compliance with applicable environmental, health and safety requirements, and that rules and policies are in place and functioning appropriately and consistently throughout the company.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the Environmental Cost Recovery Clause ("ECRC") for the January 2009 through December 2009 projection period are activities necessary for the company to comply with various environmental requirements. Specifically, I will describe the ongoing activities that are associated with the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection ("FDEP") and the Consent Decree ("CD") lodged with the U.S. Environmental Protection Agency ("EPA") and the Department of Justice. I will also discuss other

programs previously approved by the Commission for recovery through the ECRC as well as the suspension of the Clean Water Act Section 316(b) Phase II Study. Finally, I will discuss the sulfur dioxide ("SO_2") emission allowance sales for 2009 and the company's position for future allowance needs.

Q. Please provide an overview of the ongoing environmental compliance requirements that are the result of the CFJ and the CD ("the Orders").

A. The general ongoing requirements of the Orders provide for further reductions for SO_2, particulate matter ("PM") and nitrous oxides ("NO_x") emissions at Big Bend Station.

Q. What do the Orders require for SO_2 emission reductions?

A. The Orders require Tampa Electric to create a plan for optimizing the availability and removal efficiency of the flue gas desulfurization systems ("FGD" or "scrubbers"). The plan was submitted to the EPA in two phases, and both were approved.

Phase I required Tampa Electric to work scrubber outages around the clock and to utilize contract labor, when

necessary, to speed the return of a malfunctioning scrubber to service. In addition, Phase I required Tampa Electric to review all critical scrubber spare parts and increase the number and availability of spare parts to ensure a speedy return to service of a malfunctioning scrubber.

Phase II outlined capital projects Tampa Electric was to perform to upgrade each scrubber at Big Bend Station. It also addressed the use of environmental dispatching in the event of a scrubber outage. All of the preliminary SO_2 emissions reduction projects have been completed. However, additional work will occur in 2009 associated with the Big Bend Units 1 and 2 FGD and Big Bend FGD System Reliability programs to comply with the elimination of the allowed scrubber outage days for 2010 and 2013.

Q. What do the Orders require for PM emission reductions?

A. The Orders require Tampa Electric to develop and implement a best operational practices ("BOP") study to minimize PM emissions from each electrostatic precipitator ("ESP") and complete and implement a best available control technology ("BACT") analysis of the

ESPs at Big Bend Station. The Orders also require the company to demonstrate the operation of a PM continuous emissions monitoring system ("CEM") on Big Bend Units 3 and 4 and demonstrate the operation of a second PM CEM on another Big Bend unit. Pursuant to the Orders, the installation of the second PM CEM was required on or before May 1, 2007, if the first PM CEM has been shown to be feasible and remains in operation and if Tampa Electric advises the EPA that it has elected to continue to combust coal in Big Bend Units 1, 2 and 3. The first PM CEM was installed in February 2002. The installation of the second PM CEM will be completed within 18 months of approval of the pending second amendment to the CD. The amendment has not been opposed by any of the involved parties and is currently in the final administrative stages of approval.

Q. Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated capital and O&M expenditures for the period of January 2009 through December 2009.

A. The Big Bend PM Minimization and Monitoring program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the

Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric had previously identified various projects to improve precipitator performance and reduce PM emissions as required by the Orders. In 2009, there will be capital expenditures associated with the installation of a second PM CEM, O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures. Moving forward with the project will improve generation availability by providing real time PM emissions data. These activities are expected to result in approximately $492,900 of capital and $455,000 of O&M expenses.

Q. What do the Orders require for NO_x reductions?

A. The Orders require Tampa Electric to perform NO_x emissions reduction projects on Big Bend Units 1, 2 and 3 and pursuant to an amendment, for Big Bend Unit 4 projects to be substituted for Big Bend Unit 3 projects. The NO_x emissions reductions use the 1998 NO_x emissions as the baseline year for determining the level of reduction achieved. Tampa Electric was also required by the Orders to demonstrate innovative technologies or provide additional NO_x technologies beyond those required by the

early NO_x emissions reduction activities.

Q. Please describe the Big Bend NO_x Emissions Reduction program activities and provide the estimated capital and O&M expenses for the period of January 2009 through December 2009.

A. The Big Bend NO_x Emissions Reduction program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. In 2009, Tampa Electric will perform maintenance on the previously approved and installed NO_x abatement equipment. This activity is expected to result in approximately $358,000 of O&M expenses.

Q. Please describe long-term NO_x requirements associated with the Orders and Tampa Electric's efforts to comply with the requirements.

A. The Orders require Big Bend Unit 4 to begin operating with a Selective Catalytic Reduction ("SCR") system or other NO_x control technology, be repowered, or be shut down and scheduled for dismantlement by June 1, 2007. Big Bend

Units 3, 2 and/or 1 must either begin operating with an SCR system or other NO_x control technology, be repowered, or be shut down and scheduled for dismantlement one unit per year by May 1, 2008, May 1, 2009 and May 1, 2010, respectively.

In order to meet the NO_x emission rates and timing requirements of the Orders, Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to assist with the performance of a comprehensive study designed to identify the long-range plans for the generating units at Big Bend Station. The results of the study clearly indicated that the option to remain coal-fired at Big Bend Station and install the necessary NO_x reduction technologies is the most cost-effective alternative to satisfy the NO_x emissions reductions required by the Orders. This decision was communicated to the EPA and FDEP in August 2004. Tampa Electric also apprised the Commission of this decision in its filing made in Docket No. 040750-EI in August 2004.

Q. Please describe the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Units 1 through 4 SCR projects and provide estimated capital and O&M expenditures for the period of January 2009 through December 2009.

A. In Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI, issued October 11, 2004, the Commission approved cost recovery of the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Unit 4 SCR projects. The Big Bend Units 1 through 3 SCR projects were approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI, issued May 9, 2005. The purpose of the Pre-SCR technologies is to reduce inlet NO_x concentrations to the SCR systems, thereby mitigating overall SCR capital and O&M costs. These Pre-SCR technologies include neural networks, windbox modifications, secondary air controls and coal/air flow controls. The SCR projects at Big Bend Units 1 through 4 encompass the design, procurement, installation and annual O&M expenses associated with an SCR system for each unit.

The projected costs for the period of January 2009 through December 2009 for which Tampa Electric is seeking ECRC recovery are for the Big Bend Units 1 through 3 Pre-SCR and Big Bend Units 2, 3 and 4 SCR capital and O&M expenditures associated with the engineering, procurement, construction, start-up, tuning, operation and ongoing maintenance for the projects. No capital expenditures are anticipated for Big Bend Units 2 or 3 Pre-SCR for 2009 however, $77,000 is projected for O&M expenses for Unit 2

Pre-SCR but there are no O&M expenses for Unit 3 Pre-SCR. The projected capital expenditure for Big Bend Unit 1 Pre-SCR is $255,800 with $77,000 O&M expenses expected for the year. Big Bend Unit 3 SCR was placed in-service July 2008. Therefore, there are no anticipated capital expenditures for 2009, however the O&M expenditures for the project are anticipated to be $2,204,900. Big Bend Unit 4 SCR was placed in-service May 2007, therefore there are no anticipated capital expenditures for 2009. The O&M expenses for this project are anticipated to be $1,252,800. Big Bend Unit 2 SCR is expected to be in-service April 2009 and will have anticipated capital and O&M costs of $19,750,200 and $1,807,700, respectively.

The projected capital expenditures for Big Bend Unit 1 is $34,218,913. However, as stated in Tampa Electric Witness Howard T. Bryant's Prepared Direct Testimony in this docket, the company will not seek recovery of capital expenditures until the in-service date for the project has occurred.

Q. Please identify and describe the other Commission approved programs you will discuss.

A. The programs previously approved by the Commission that I

will discuss include:

1) Big Bend Unit 3 FGD Integration

2) Big Bend Units 1 and 2 FGD

3) Gannon Thermal Discharge Study

4) Bayside SCR Consumables

5) Big Bend Unit 4 Separated Over-fired Air ("SOFA")

6) Clean Water Act Section 316(b) Phase II Study

7) Big Bend FGD Reliability

8) Arsenic Groundwater Standard

9) Clean Air Mercury Rule ("CAMR")

Q. Please describe the Big Bend Unit 3 FGD Integration and the Big Bend Units 1 and 2 FGD activities and provide the estimated capital and O&M expenditures for the period of January 2009 through December 2009.

A. The Big Bend Unit 3 FGD Integration program was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The Big Bend Units 1 and 2 FGD program was approved by the Commission in Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999. In those Orders, the Commission found that the programs met the requirements for recovery through the ECRC. The programs were implemented to meet the SO_2 emissions requirements of the Phase I and II Clean

Air Act Amendments ("CAAA") of 1990.

The projected January 2009 through December 2009, O&M expenses for the Big Bend Unit 3 FGD Integration project are $3,658,000. No capital expenditures are anticipated for this project. The projected January 2009 through December 2009, capital and O&M expenditures for the Big Bend Units 1 and 2 FGD project are $2,111,200 and $7,482,800, respectively. The major components of the capital expenditures are projected to be for the electric isolation, mist eliminator upgrades, redundant gypsum bleed line and controls redundancy.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated capital and O&M expenditures for the period of January 2009 through December 2009.

A. The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 010593-EI, Order No. PSC-01-1847-PAA-EI, issued September 14, 2001. In that Order, the Commission found that the program met the requirements for recovery through the ECRC. For the period of January 2009 through December 2009, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses will be approximately $50,000 for the period.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated capital and O&M expenditures for the period of January 2009 through December 2009.

A. The Bayside SCR Consumables program was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. For the period of January 2009 through December 2009, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses associated with the consumable goods (primarily anhydrous ammonia) will be approximately $82,000 for the period.

Q. Please describe the Big Bend Unit 4 SOFA program activities and provide the capital and O&M expenditures for the period of January 2009 through December 2009.

A. The Big Bend Unit 4 SOFA program was approved by Commission for ECRC recovery in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2003. In that Order, the Commission found that the program met the requirements for recovery through the ECRC contingent upon Big Bend Unit 4 remaining coal fired. On August 19, 2004, Tampa Electric submitted a letter to the EPA

declaring the intent for Big Bend Units 1 through 4 to remain coal fired and, as such, complied with the applicable provisions of the CD associated with the decision. The SOFA project was completed in 2004. For the period of January 2009 through December 2009, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses will be approximately $50,000 for the period.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study program activities and provide the estimated capital and O&M expenditures for the period of January 2009 through December 2009.

A. The Clean Water Act Section 316(b) Phase II Study program was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005. For the period of January 2009 through December 2009, there will be no capital expenditures for this program. EPA announced on March 20, 2007, that the rule adopted pursuant to Section 316(b) be considered suspended. The suspension of the final rule was made on July 9, 2007. Tampa Electric believes that the work will continue to be useful for purposes related to the Phase II Rule and does not intend to suspend the work because it would not be

cost-effective or appropriate to do so. Therefore, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $150,000 for the period.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital and O&M expenses for the period of January 2009 through December 2009.

A. Tampa Electric's Big Bend FGD System Reliability program was approved by the Commission 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. The Big Bend FGD System Reliability project will run concurrently with the installation of SCR systems on the generating units.

For the period of January 2009 through December 2009, there are no capital or O&M expenditures anticipated for this project.

Q. Please describe the Arsenic Groundwater Standard program activities and provide the estimated capital and O&M expenditures for the period of January 2009 through

December 2009.

A. The Arsenic Groundwater Standard program was approved by the Commission in Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006. In that Order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs. The new groundwater standard applies to Tampa Electric's H.L. Culbreath Bayside, Big Bend and Polk Power Stations.

For the period of January 2009 through December 2009, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $114,000.

Q. Please describe the CAMR program activities and provide the estimated capital and O&M expenditures for the period of January 2009 through December 2009.

A. The CAMR program was approved by the Commission in Docket No. 060583-EI, Order No. PSC-06-0926-PAA-EI, issued November 6, 2006. In that Order, the Commission found that the program met the requirements for recovery through

the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs.

On February 8, 2008, the Washington D.C. Circuit Court vacated EPA's rule removing power plants from the Clean Air Act list of sources of hazardous air pollutants. At the same time, the Court vacated the Clean Air Mercury Rule. EPA is reviewing the Court's decisions and evaluating its impacts. Currently, the FDEP has informally announced their intention to begin mercury rulemaking in fall 2008 that will likely have monitoring requirements comparable to CAMR.

Given the vacatur, capital spending for this program is anticipated to be complete in 2008 and monitoring to commence in 2009 using company resources. Therefore, for the period of January 2009 through December 2009, there will be no capital or O&M expenditures for this program.

Q. Please describe how Tampa Electric reached the decision to sell SO_2 emission allowances in 2009 and discuss the company's allowance needs for 2009 and beyond.

A. After the completion of the repowering project at Bayside Power Station, Tampa Electric performed a thorough

evaluation of SO_2 emission allowance needs based on current system conditions and those projected to occur over the next 20 years. Current system conditions included the reduction in coal usage due to repowering and the impacts of the CD and CFJ on SO_2 emission allowances. Future conditions took into account generation expansion and the impact of new federal environmental regulations on SO_2 emission allowances. At the conclusion of the evaluation, it became evident that the company had a surplus of allowances that could be sold in the allowance marketplace. Furthermore, there will be an adequate remaining allowance inventory that will meet the company's needs for the next 20 years.

In balancing the appropriate quantity to sell with the company's expected future needs, Tampa Electric will continue to evaluate potential sales opportunities of future quantities of surplus allowances.

Q. What is the impact of the recent vacatur of the CAIR and CAMR rules on Tampa Electric's ECRC projects?

A. The vacatur of CAIR should have minimal impact on Tampa Electric's ECRC projects associated with NO_x and SO_2 abatement. These projects were initiated as a result of

the CD signed between EPA and Tampa Electric therefore, the company anticipates continuing its efforts to complete and maintain the projects.

The vacatur of CAMR occurred after Tampa Electric had begun the procurement of equipment necessary to meet the intent of the original rule; however, the company was able to stop a significant portion of the total equipment purchase.

Tampa Electric anticipates a replacement to the CAMR rule to become effective in the near future therefore, during this time of review, the company plans to utilize the resources already secured to establish a baseline of mercury emissions.

Q. Please summarize your testimony.

A. Tampa Electric's settlement agreements with FDEP and EPA require significant reductions in emissions from Tampa Electric's Big Bend and Gannon Stations. The Orders established definite requirements and time frames in which air quality improvements must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies.

My testimony identified projects which are legally required by these Orders. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I have identified estimated costs, by project, which the company expects to incur in 2009. Additionally, my testimony identified other projects that are required for Tampa Electric to meet the environmental requirements and I provided the associated 2009 activities and projected expenditures. Finally, I addressed the prudent sales of SO_2 emissions allowances that are anticipated to occur in 2009 and demonstrated that Tampa Electric's approach toward the allowance quantity contained in the sales will not jeopardize the company's long-term future allowance needs.

Q. Does this conclude your testimony?

A. Yes it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
James O. Vick
Docket No. 080007-EI
April 2, 2008

Q. Please state your name and business address.

A. My name is James O. Vick and my business address is One Energy Place, Pensacola, Florida, 32520.

Q. By whom are you employed and in what capacity?

A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Mr. Vick, will you please describe your education and experience?

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. In August 1978, I joined Gulf Power Company as an Associate Engineer and have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003, I assumed my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs area to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e. both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I am responsible for numerous environmental activities.

Q. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's Environmental Cost Recovery Clause (ECRC) final true-up for the period January through December 2007.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have. My exhibit includes the following document:

- Letter of Clarification from the Florida Department of Environmental Protection (FDEP) on Department Policy after Environmental Protection Agency (EPA) Suspension of 316(b) Phase II Existing Facilities Rule

Counsel: We ask that Mr. Vick's exhibit consisting of one document be marked as Exhibit No. _____(JOV-1).

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2007 through December 2007 with the approved estimated true-up amounts.

A. As reflected in Ms. Martin's Schedule 6A, the actual recoverable capital costs were $33,735,639 as compared to the estimated true-up total of $33,857,505. This results in a variance of $121,866 or 0.4% below the estimated true-up. I will address two projects that contribute to this variance: Precipitator Upgrades for CAM Compliance and SO_2 Allowances.

Q. Please explain the capital project variance of (5.2%) or ($109,704) in Precipitator Upgrades for CAM Compliance (Line Item 1.22).

A. At the time of the 2007 ECRC estimated/actual true-up filing, Gulf expected the Crist Unit 5 precipitator upgrade to be completed by December 2007; however, the project was not placed in service until March of 2008 due to changes in the unit outage schedule. This change in the timing of the Crist Unit 5 upgrade was reflected in the 2008 projection filing.

Q. Please explain the capital variance of 36.0% or $22,079 in SO_2 Allowances (Line Item 1.28).

A. This variance resulted from the fact that the sulfur content of the coal actually burned during the period was lower than anticipated. This lower sulfur

content allowed Gulf to surrender fewer SO_2 allowances from inventory, meaning that Gulf's inventory balance and working capital was higher than anticipated.

Q. How do the actual O&M expenses for the period January 2007 to December 2007 compare to the amounts included in the estimated true-up filing?

A. Ms. Martin's Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $16,904,925, as compared to the estimated true-up of $17,849,512. This results in a net variance of $944,587 or 5.3% below the estimated true-up. I will address eight O&M projects and programs that contribute to this variance -- Title V, Emission Monitoring, General Water Quality, State NPDES Administration, General Solid and Hazardous Waste, Above Ground Storage Tanks, FDEP NO_X Reduction Agreement, and SO_2 Allowances.

Q. Please explain the (13.6%) variance of ($10,905) in Title V (Line Item 1.3).

A. Title V expenses are associated with the implementation of Gulf's Title V permits. There were no significant modifications to the Plants Smith and Scholz Title V permits during 2007. Therefore, the expenses associated with these permits were less than previously projected.

Q. Please explain the variance of (10.2%) or ($49,060) in the category Emission Monitoring (Line Item 1.5).

A. The Emission Monitoring variance resulted primarily from the Daniel continuous emission monitoring (CEM) expenses recoverable through the

ECRC being less than originally projected. The CEM maintenance expenses at Plant Daniel were also lower than expected due to the installation of new flow monitors in October of 2007.

Q. Please explain the variance of 12.5% or $42,989 in the category General Water Quality (Line Item 1.6).

A. The General Water Quality variance resulted primarily from re-initiating portions of the Cooling Water Intake Program biological sampling and data collection plan. The scope of Gulf's 2007 Cooling Water Intake Program biological sampling plan was reduced in March of 2007, as reflected in the estimated/actual true-up filing, after EPA announced that the rule it adopted pursuant to Section 316(b) of the Clean Water Act should be considered suspended. After the estimated/actual true-up filing, Gulf decided to move forward with these plans after receiving guidance from FDEP regarding implementation of Section 316(b) of the Clean Water Act. A copy of the letter from FDEP is included in my exhibit.

Q. Please explain the 99.3% variance of $34,500 in the category State NPDES Administration (Line Item 1.8).

A. This variance resulted from the timing of payment of the 2008 annual state National Pollution Discharge Elimination System (NPDES) industrial wastewater permit fees. The fees were paid during December 2007, but had been projected for January 2008.

Q. Please explain the 23.3% variance of $128,982 in Line Item 1.11, General Solid and Hazardous Waste.

A. This line item includes expenses for proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. The 2007 variance resulted primarily from inadvertently omitting waste removal and disposal costs for Gulf's power delivery facilities from the estimated/actual true-up filing; however, these expenses were appropriately included in Gulf's original 2007 projection.

Q. Please explain the variance of (40.8%) or ($41,195) in the category entitled Above Ground Storage Tanks (Line Item 1.12).

A. Plant Crist originally planned to recoat several above ground storage tank concrete secondary containment areas during 2007. After further evaluation, Plant Crist determined that this work could be postponed.

Q. Please explain the (6.2%) variance of ($185,238) in Line Item 1.19, FDEP NO_X Reduction Agreement.

A. This O&M line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the FDEP NO_X Reduction Agreement. The project variance resulted primarily from delaying maintenance expenses associated with the Crist Unit 5 Selective Non-Catalytic Reduction (SNCR) urea injection system from 2007 to 2008 due to a change in the outage schedule. This under run was partially offset by an increase in the Crist Unit

7 Selective Catalytic Reduction (SCR) and Crist Units 4 – 6 SNCR maintenance expenses.

Q. Please explain the variance of (7.5%) or ($814,773) in SO_2 Allowances (Line Item 1.20).

A. This variance resulted from the fact that the sulfur content of the coal actually burned during the period was lower than anticipated. This lower sulfur content allowed Gulf to surrender fewer SO_2 allowances.

Q. Mr. Vick, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 080007-EI
August 4, 2008

Q. Please state your name and business address.

A. My name is James O. Vick and my business address is One Energy Place, Pensacola, Florida, 32520.

Q. By whom are you employed and in what capacity?

A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Mr. Vick, will you please describe your education and experience?

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. I joined Gulf Power Company in August 1978 as an Associate Engineer. I have since held various engineering positions with increasing responsibilities such as Air Quality Engineer and Senior Environmental Licensing Engineer. In 2003, I assumed

my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs section to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I am responsible for numerous environmental activities.

Q. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's estimated true-up for the period from January 1, 2008 through December 31, 2008. This true-up is based on six months of actual data and six months of estimated data.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 1, 2008 through December 31, 2008 with approved projected amounts.

A. As reflected in Ms. Ritenour's Schedule 6E, the recoverable capital costs approved in the original projection total $37,497,220, as compared

to the estimated true-up amount of $38,990,615. This results in a projected variance of $1,493,395. There are two capital projects and programs that contributed to the majority of this variance: the CAIR/CAMR/CAVR Compliance Program and SO_2 allowances. The variances for these projects are discussed below.

Q. Please explain the $1,376,116 variance in the CAIR/CAMR/CAVR Compliance Program (Line Item 1.26).

A. The majority of this variance is a result of clearings to plant for portions of the Plant Crist scrubber project being inadvertently omitted from the original 2008 projection. The Units 4 and 5 boiler controls and ductwork modifications were placed in-service during the April-May 2008 timeframe and the substation/transmission upgrades are scheduled to be placed in-service during December of 2008. Expenditures for these upgrades were included in the 2008 budget projection; however, the expected plant clearings associated with the upgrades were not included in the projection filing.

It was necessary for Plant Crist to upgrade the Units 4 and 5 boiler controls in order for the units to tie into a common scrubber vessel and draft system with Crist Units 6 and 7. The original boiler controls did not meet the speed and reliability requirements necessary for proper draft control and boiler implosion protection that will be required for a combined discharge into the common scrubber stack. The substation/transmission upgrades were necessary to provide additional station service needs necessary to operate the Crist Units 4 through 7 scrubber. The Plant Crist scrubber variance was partially offset by the cancellation of the Daniel Activated Carbon Injection (ACI) project after

vacatur of the Clean Air Mercury Rule (CAMR) rule earlier this year.

Q. Please discuss the CAMR vacatur and its affect on Gulf's CAIR/CAMR/CAVR Compliance Program (Line Item 1.26).

A. 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. With CAMR voided, electric generating facilities are no longer required to install mercury controls to meet the CAMR emission limits and are not required to install mercury monitoring equipment to meet the January 2009 monitoring deadline. In response to the CAMR vacatur Gulf has canceled the Plant Daniel ACI and mercury monitoring projects and moved further mercury monitoring capital costs out to at least 2010.

EPA can be expected to initiate a rulemaking proceeding to develop maximum achievable control technology (MACT) standards for power plants; however, this process could take up to three years to complete. The CAMR court decision does not impact state mercury rules that may continue to be developed in Florida.

Q. Please explain the $87,381 variance in SO_2 Allowances in Line Item 1.31.

A. As explained in the 2007 Final True-Up filing, Gulf's 2007 SO_2 allowance inventory balance and net working capital balance was higher than anticipated because the sulfur content of the coal burned during 2007 was lower than Gulf projected. As a result, the 2008 projected variance is due to

higher revenue requirements on this higher balance.

Q. How do the estimated/actual O&M expenses compare to the original projection?

A. Ms. Ritenour's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated to be $15,216,886 as compared to the original projection of $14,148,879. This will result in a year-end variance of $1,068,007. There are four O&M projects and programs that contributed to the majority of this variance which I will discuss: Groundwater Contamination Investigation; General Solid and Hazardous Waste; FDEP NOx Reduction Agreement; and the CAIR/CAMR/CAVR Compliance Program.

Q. Please explain the variance of $107,961 in Groundwater Contamination Investigation (Line Item 1.7) and the $42,306 variance in General Solid and Hazardous Waste (Line Item 1.11).

A. These variances are due to an error in the calculation of total labor costs included in the projection filing.

Q. Please explain the variance of $652,104 in Line Item 1.19, FDEP NOx Reduction Agreement.

A. The FDEP NOx Reduction Agreement includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the Plant Crist FDEP Agreement for Ozone Attainment. The project variance primarily

resulted from additional maintenance expenses associated with the Crist Units 4 and 5 Selective Non-Catalytic Reduction (SNCR) urea injection systems. As mentioned in Gulf's ECRC 2007 Final True-Up filing, the Unit 5 maintenance activities were postponed from 2007 to 2008 due to a change in the outage schedule. In addition, the Unit 4 maintenance expenses were not included in the Plant Crist budget projection.

Q. Please explain the variance of $197,866 in CAIR/CAMR/CAVR Compliance Program (Line Item 1.20).

A. During 2007, capital expenditures for ACI systems at Plant Daniel were added to Gulf's Compliance Plan for mercury control as part of the obligation to meet CAMR requirements beginning in 2010. Based on the vacatur of CAMR earlier this year, the Plant Daniel ACI projects have been removed from the compliance schedule and budget projections. The Daniel mercury monitors that were scheduled to be placed in-service during 2008 were also removed from the compliance schedule and the budget. Capital expenditures that Gulf incurred for these projects prior to the CAMR vacatur were expensed to Line Item 1.20 when the projects were canceled.

Q. Mr. Vick, are there any other O&M project variances that you would like to explain?

A. Yes, the Emission Monitoring line item, Line Item 1.5, had a ($132,937) variance. This variance is primarily related to Compliance Assurance Monitoring (CAM) certification testing associated with Gulf's Title V permit renewals. The testing originally planned for this permit renewal cycle has not

yet occurred and FDEP may not require this testing. Relative accuracy test audit (RATA) expenses were also less than originally projected. Fewer RATA tests have been required than originally expected.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony and Exhibit of

James O. Vick

Docket No. 080007-EI

August 29, 2008

Q. Please state your name and business address.

A. My name is James O. Vick, and my business address is One Energy Place, Pensacola, Florida, 32520.

Q. By whom are you employed and in what capacity?

A. I am employed by Gulf Power Company as the Director of Environmental Affairs.

Q. Mr. Vick, will you please describe your education and experience?

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. I joined Gulf Power Company in August 1978 as an Associate Engineer. I have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003,

I assumed my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs section to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I have the responsibility for numerous environmental activities.

Q. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?

A. Yes.

Q. Mr. Vick, what is the purpose of your testimony?

A. The purpose of my testimony is to support Gulf Power Company's projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) for the period from January 2009 through December 2009.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have. My exhibit includes the following documents:

- Plant Crist Consumptive Use Permit
- Northwest Florida Water Management District (NWFWMD)

correspondence regarding the proposed Crist Water Conservation project.

Counsel: We ask that Mr. Vick's' Exhibit consisting of two documents be marked as Exhibit No. _(JOV-2).

Q. Mr. Vick, please identify the capital projects included in Gulf's ECRC projection filing.

A. The environmental capital projects for which Gulf seeks recovery through the ECRC are described in Schedules 3P, 4P, and 5P attached to the Company's petition in this docket. The exhibits attached to the petition have been incorporated into hearing exhibits that are being sponsored in this proceeding by Ms. Ritenour. I am supporting the expenditures, clearings, retirements, salvage and cost of removal currently projected for each of these projects and the monthly costs for emission allowances. Ms. Ritenour compiled these schedules and has calculated the associated revenue requirements for Gulf's requested recovery.

Q. Have all of the capital projects shown on Ms. Ritenour's schedules been approved by the Commission?

A. No. In addition to previously approved projects, Gulf's 2009 ECRC capital projection includes both new projects and expansions of existing, previously approved projects.

Q. Mr. Vick, please identify the expansions of existing, previously approved projects.

A. There are four previously approved projects with expanded activities that have projected capital expenditures during 2009. Three of the projects are related to Gulf's existing Air Quality programs: Continuous Emission Monitoring (CEMs) replacements, Plant Crist FDEP Agreement for Ozone Attainment, and the CAIR/CAMR/CAVR Compliance Program. The Crist Water Conservation Project is also projected to have additional capital expenditures during 2009.

Q. Mr. Vick, please describe the projects included in the 2009 projection for (Line 1.5) Continuous Emission Monitoring (CEM).

A. During the 2009 recovery period, 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. Opacity monitors are needed to maintain compliance with the Clean Air Act Amendment (CAAA) requirements. The existing monitors are approaching the end of their useful lives and will be retired upon replacement. 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. The 2009 expenditures are expected to be $439,830.

Q. Please describe the expenditures included in the 2009 projection for the Crist FDEP Agreement for Ozone Attainment (Line 1.19).

A. For the 2009 projection, Gulf has included additional capital costs to meet the terms of the August 28, 2002, agreement with the Florida Department of Environmental Protection (FDEP). Gulf will be installing a new layer of catalyst in the Crist Unit 7 Selective Catalytic Reduction (SCR) during 2009 that was originally projected to be installed during 2008. This new layer of catalyst is part of the on-going periodic catalyst maintenance and management activity. The projected 2009 capital expenditures for the Crist FDEP Agreement project are $720,000.

Q. Mr. Vick, please describe the capital projects included in Gulf's CAIR/CAMR/CAVR Compliance Program (Line Item 1.26) that will impact the 2009 projected ECRC revenue requirements.

A. For the purpose of the 2009 projection of ECRC revenue requirements in Ms. Ritenour's testimony, expenditures totaling $521.9 million are projected to be cleared to plant-in-service for the CAIR/CAMR/CAVR Compliance Program. This placed-in-service amount includes expenditures made during 2009 as well as previous years. The capital projects included in the Compliance Program that will impact the 2009 ECRC revenue requirements are the Crist Units 4 through 7 scrubber project ($517.5 million), Low NOx burners at Plant Daniel on Unit 2 ($167,276), and Selective Non-Catalytic Reduction (SNCR) technologies at Plant Smith on Unit 1 ($3.9 million) and Unit 2 ($371,502).

Q. Please describe the Crist Units 4 through 7 scrubber project.

A. The Commission approved the Crist Units 4 through 7 scrubber project for ECRC recovery in Order No. PSC-07-0721-S-EI in September 2007. As noted in its original CAIR/CAMR/CAVR Compliance Plan, Gulf proposed the Crist Scrubber project to assure compliance with Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR) and address the significant local concerns in the Pensacola area. A scrubber was the only SO_2 compliance option for Crist Units 6 and 7, and because of their size and emissions, these units were the best, most cost-effective candidates for SO_2 scrubbing and mercury removal. Installing additional ductwork and boiler controls to include Crist Units 4 and 5 was also cost-effective and increased incremental SO_2 and mercury emission reductions. Construction was scheduled to take place between 2007 and 2009 at an estimated cost of $528 million.

The total budget for the Plant Crist scrubber project is now approximately $576 million for the time period from 2007 to 2012. Most of the cost increase is due to the decision to install turbine upgrades to offset increased station losses due to the scrubber installation ($12 million for HP/IP turbine upgrades and $26 million for LP turbine upgrades) and the purchase of rather than the lease of gypsum barges ($8.5 million). The extended project timeframe is also due to adding the LP turbine upgrade to the project. A phased approach for the turbine upgrades has been adopted due to the availability of LP parts and the outage schedule.

The Plant Crist scrubber project is well underway, and numerous supporting facilities will be placed in-service during 2009. Other than the

LP turbine upgrades scheduled for 2012, most of the scrubber project is scheduled to be completed during 2009 including the Crist HP/IP turbine upgrade, gypsum tractor garage and barges, and substation and transmission upgrades.

At present, the work force for the project has been mobilized. Site preparation activities for the future gypsum dewatering and handling facilities, fuel handling relocations, limestone handling and storage, as well as the deep well location and project laydown infrastructure have been performed. The foundation and concrete column of the new 490 foot stack has also been completed. The stack liner sections have been fabricated and are ready for installation. Numerous foundations are complete, with the largest being the Jet Bubbling Reactor (JBR) foundation. Fabrication of the fiberglass JBR shell has begun which, when completed, will be 119 feet in diameter and 55 feet tall. Several other foundations are currently being constructed, most of which have included deep foundation work (auger cast piles, pipe piles, etc.). The foundations include ductwork support steel foundations, draft fan foundations, power transformer foundations, and temporary foundations for on-site fabrication.

By year end 2008 the Plant Crist scrubber project is estimated to be 55% complete. Projected capital expenditures for 2009 for the scrubber project are $243 million.

Q. Please address the projected capital expenditures in 2009 for the Daniel Low NOx burners.

A. Gulf is a co-owner of Daniel Units 1 and 2 with Mississippi Power Company. A number of retrofit projects for the Daniel units were set forth in Gulf's CAIR/CAMR/CAVR Compliance Plan, and all those projects other than SCRs for Units 1 and 2 were approved by the Commission in Order No. PSC-07-0721-S-EI (Mercury Monitoring, SNCRs and Low NOx Burners, and the Scrubber). In light of the CAIR and CAMR developments, many of the approved Plant Daniel projects have been canceled or deferred. The Daniel Unit 2 Low NOx burner remains the only part of the Compliance Plan that has projected capital expenditures for Plant Daniel during 2009. The Daniel Unit 2 Low NOx burners were ordered prior to the CAIR vacatur and are scheduled to be placed in-service during December of 2008. $167,276 of additional capital expenditures related to this project are forecast to be cleared to service in 2009.

Q. Please address Smith Units 1 and 2 SNCR capital expenditures forecasted for 2009.

A. SNCR installations for Smith Units 1 and 2 were approved by the Commission in Order No. PSC-07-0721-S-EI as part of Gulf's CAIR/CAMR/CAVR Compliance Plan. In addition to meeting CAIR requirements, the SNCRs will be needed to maintain local compliance with the more stringent 8-hour ozone standard. The Smith Unit 2 SNCR will be placed in service in the fall of 2008, but additional capital

expenditures of $371,502 are forecast for 2009. The Smith Unit 1 SNCR will be placed in-service during March of 2009. The 2009 projected clearings to plant for the Smith Unit 1 SNCR are approximately $ 3.9 million.

Q. Have there been any developments regarding Gulf's CAIR/CAMR/CAVR Compliance Program that have an impact on capital projects projected for recovery during 2009?

A. Yes. Since the Commission's approval of Gulf's Compliance Program, there have been a number of developments and two significant court decisions that will impact Gulf's Compliance Program. In February 2008 the District of Columbia Court of Appeals vacated the CAMR. In July 2008 the District of Columbia Court of Appeals also vacated the CAIR rule.

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. With CAMR voided, electric generating facilities are no longer required to install mercury controls to meet the CAMR emission limits and are not required to install mercury monitoring equipment to meet the January 2009 monitoring deadline. In response to the CAMR vacatur, the Plant Daniel Activated Carbon Injection (ACI) and mercury monitoring projects have been canceled. The Plants Crist and Smith mercury monitoring capital expenditures have been deferred to

2010.

EPA can be expected to initiate a rulemaking proceeding to develop maximum achievable control technology (MACT) standards for power plants; however, this process could take multiple years to complete. The CAMR court decision does not impact state mercury rules that may continue to be developed in Florida.

On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of the CAIR, the Circuit Court of Appeals for the District of Columbia issued a decision vacating CAIR in its entirety, and remanding it to EPA for further action consistent with its opinion. However, CAIR will remain in effect until the court issues its mandate in the case. Recently, the court extended until late September EPA's time for requesting reconsideration of the court's decision, and no mandate from the court is expected before that time. Therefore, the CAIR remains in effect and technically requires compliance. In addition, FDEP rules requiring CAIR implementation also remain in effect as of the time of the submission of this testimony.

Gulf Power's overall compliance strategy has been developed in response to numerous federal and state regulatory requirements, many of which remain unaffected by the court's ruling; however, the court's decision has the potential to impact future decisionmaking regarding capital expenditures, the installation and operation of pollution control equipment, the purchase of emissions allowances, and the carrying cost of the existing emissions allowances. The ultimate impact of this decision, if any, cannot be determined at this time and may depend on subsequent

legal action, including issuance of the court's mandate, and future EPA and FDEP rulemaking.

Q. How have these developments affected Gulf's Crist scrubber project?

A. In terms of timing, the Crist scrubber is needed for Phase I CAIR compliance in 2010. If the vacatur of the CAIR becomes final, Gulf anticipates that the Crist Scrubber project would still be needed for Crist Units 6 and 7 to comply with the CAVR by 2013. Given that the Crist Scrubber project is still needed for CAVR compliance, regardless of the resolution of CAIR, the issue Gulf faced was whether or not to defer the Crist Scrubber project for several years. Gulf determined that the Crist Scrubber project should proceed for a variety of reasons. First, over $175 million of equipment has already been ordered. Second, significant construction has already occurred, and the construction workforce has been fully mobilized; deferral would significantly increase the total project costs. As noted earlier, the project will be approximately 55% complete by the end of 2008. Demobilization would mean the potential loss of personnel already on site. Deferral for three years until 2012 to meet 2013 CAVR requirements would increase the construction cost of the project by approximately $53 million. The associated increase in AFUDC, which Gulf would seek for recovery, would be at least $45 million. Thus, deferral would cost around $100 million. Third, if the CAIR rule eventually is vacated, it is also reasonable to anticipate that EPA and/or FDEP will act again to address the same issues. If they do, the scrubber project would continue to be the best, most cost-effective means of limiting SO_2

and mercury emissions, with Gulf potentially facing increased costs in order to meet accelerated in service dates.

Q. How have these developments regarding CAIR and CAMR affected other aspects of Gulf's CAIR/CAMR/CAVR Compliance Plan?

A. That is best addressed on a plant by plant basis.

The Crist Unit 6 SCR was approved as part of Gulf's CAIR/CAMR/CAVR Compliance Plan in Order No. PSC-07-0721-S-EI. As noted in the Compliance Plan and the Commission's order, the Crist Unit 6 SCR is needed to meet NOx reductions. Additional NOx reductions are needed at Plant Crist, and only SCR technology will provide the additional increment needed. The SCR on Unit 6 is important to ensure that Pensacola maintains attainment with the newly announced 8-hour ozone standard and addresses significant local pressures to continue NOx reductions from the plant. Finally, the Crist Unit 6 SCR was also needed for CAIR and CAMR compliance. While CAMR compliance is no longer required, CAIR requirements still remain applicable. Even if CAIR is ultimately vacated, the Crist Unit 6 SCR will still be needed to satisfy FDEP requirements, the new 8-hour ozone standard and local pressure to reduce NOx emissions. Gulf has deferred the in-service date for the Crist Unit 6 SCR from 2010 to 2012, and is forecasting capital expenditures of almost $5 million in 2009.

As I previously discussed, the Plant Crist mercury monitoring projects have been deferred until 2010, but the CEM system for the scrubber stack is continuing with expenditures forecast for 2009. The

scrubber CEM system is included in Line Item 1.5.

The only approved activity at Plant Scholz was for mercury monitoring. The Scholz monitor was installed in 2008. There are no forecasted capital expenditures for 2009.

At Plant Smith the approved SNCRs for Units 1 and 2 are still needed for ozone non-attainment and local pressure regarding NOx emissions. Thus, they are scheduled for completion in 2008 and 2009. I have previously addressed the amounts forecasted to be placed in-service during 2009 for each project. The Plant Smith mercury monitoring projects have been deferred until 2010.

Plant Daniel Units 1 and 2 were previously scheduled to receive SNCR retrofits in 2011 and 2012, respectively. Expenditures for these projects were projected to begin in 2009. Plant Daniel planned to operate the SNCRs until the SCRs were placed in-service. The SNCR projects have since been removed from the compliance schedule, and the SCR installation has been accelerated by two years. Gulf anticipates that the Daniel SCR installations will be important to ensure that Plant Daniel maintains attainment with the newly announced 8-hour ozone standard. The Daniel SCRs were also needed for CAIR and CAMR compliance. While CAMR compliance is no longer required, CAIR requirements still remain applicable. Even if CAIR is ultimately vacated, the Daniel SCRs will likely be needed to comply with the new 8-hour ozone standard. There are no projected 2009 expenditures for the Daniel SCR projects.

The Daniel Unit 1 and 2 Low NOx burners were planned for Phase I CAIR annual and seasonal NOx cap and trade allowance programs.

Gulf determined that the Daniel Unit 2 Low NOx burner installation, which is scheduled for completion in 2008, should proceed based on the project schedule. The Daniel Unit 1 Low NOx burner project has been canceled. Similarly, the previously approved mercury monitoring for Plant Daniel has been canceled.

The Daniel scrubber project, which was previously approved by the Commission as part of Gulf's CAIR/CAMR/CAVR Compliance Plan, continues to be an effective means of reducing SO_2 and mercury emissions. It is still anticipated that this scrubber project may be required for CAVR compliance, even if it is not required for CAMR and CAIR compliance. However, there are no projected capital expenditures in 2009 for which Gulf seeks recovery in the ECRC factor.

Q. Please provide an update on the new 8-hour ozone standard implementation.

A. In March 2008, the EPA finalized its revisions to the eight-hour ozone standard, increasing its stringency. The EPA plans to designate nonattainment areas based on the new standard by 2010, and new nonattainment areas are expected. State Implementation Plans (SIPs) will be developed for these areas by 2013. These SIPs will prescribe emission control measures designed to bring areas into attainment. Although designation of a number of new nonattainment areas is anticipated, specific designations and any subsequent SIP control measures will be based in part on air quality measurements that will be made in the future. The ultimate outcome of this matter cannot be

determined at this time and will depend on subsequent legal action and/or future nonattainment designations and regulatory plans.

Q. Mr. Vick, please describe the project included in the 2009 projection entitled Crist Water Conservation (Line Item 1.24) for which Gulf is seeking cost recovery through the ECRC.

A. The Crist Water Conservation Program included in Line Item 1.24 is part of Gulf's water conservation and consumptive use efficiency program required by the Company's consumptive water use permit. Plant Crist's consumptive use permit, issued by the Northwest Florida Water Management District (NWFWMD), requires the plant to implement measures to increase water conservation and efficiency at the facility. Gulf Power has entered into negotiations with Emerald Coast Utilities Authority (ECUA) to utilize reclaimed water from its proposed wastewater treatment plant. The reclaimed water will be used as makeup water for the Plant Crist scrubber project and the Plant Crist Units 6 and 7 cooling towers. Plant Crist will also return some reclaimed water, up to 6 million gallons per day (MGD), in the form of cooling tower blowdown to ECUA as industrial wastewater for land application. The NWFWMD has agreed that this is a valid project to pursue for continued implementation of the water conservation effort. The total projected capital expenditures for this project are $17.4 million. The Plant Crist Consumptive Use Permit and correspondence from the NWFWMD regarding the Crist Water Conservation Project is included in my Exhibit, JOV-2.

For the purpose of the 2009 projection of ECRC revenue

requirements, expenditures totaling $1.3 million are projected to be incurred for portions of the Plant Crist water conservation project that will be placed in-service during 2009. These capital projects include an electrical building and piping from the storage tank to the booster pump.

Q. Mr. Vick please describe the capital projects shown on Ms. Ritenour's schedules that have not been previously approved by the Commission.

A. The Spill Prevention Control and Countermeasures (SPCC) Compliance project is needed to help ensure compliance with the revisions to the SPCC regulation, 40 CFR Part 112. These revisions 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). During 2009, Plant Smith plans to install secondary containment for a small fuel tank and a padmount transformer. The total projected capital expenditures for this project are $25,000.

These expenditures are included in Line Item 1.20, which has been renamed SPCC Compliance. As shown on Ms. Ritenour's schedules, this line item previously titled "Crist Stormwater Collection" has been renamed "SPCC Compliance" to better reflect the full scope of this activity. The "Crist Stormwater Collection" project was Gulf's first capital project required to help ensure compliance with the revised SPCC regulation.

Q. Mr. Vick, are you including the purchase of allowances in your 2009 projection filing?

A. Yes. We currently have plans to purchase annual and seasonal NOx allowances as well as SO_2 allowances during 2009. Gulf's compliance strategy continues to include forward contracts, swaps, and spot market purchases of allowances depending on market prices.

Q. Please compare the Environmental Operation and Maintenance (O&M) activities listed on Schedule 2P of Ms. Ritenour's Exhibit to the O&M activities approved for cost recovery in past ECRC proceedings.

A. All of the O&M activities listed on Schedule 2P have been approved for recovery through the ECRC in past proceedings, except for three new activities. The Annual Climate Change Registry Fees are being included in the CAIR/CAMR/CAVR Compliance Program for the first time. SPCC Compliance expenses are being included in the Solid and Hazardous Waste line item, and expenses for the Impaired Waters Rule are being included in the General Water Category line item.

Q. Mr. Vick, please describe the regulations requiring the Annual Climate Change Registry Fees that are being included in the CAIR/CAMR/CAVR Compliance Program (Line Item 1.20).

A. At the June 2008 "Serve to Preserve Florida Summit on Global Climate Change," Governor Crist signed legislation (HB 7135) creating Florida Statute 403.44, the "Florida Climate Protection Act." This Act was created to establish a market-based program to reduce greenhouse gas

emissions from electric utilities. The Act authorizes the FDEP to establish methodologies, reporting periods, and reporting systems that will be used when utilities report to the Climate Registry. Gulf Power expects to begin incurring annual costs associated with joining the Climate Registry during 2009. Gulf also anticipates incurring expenses for monitoring and reporting greenhouse gas emissions. The 2009 projected expenses for this line item are $43,000.

Q. Mr. Vick, please describe the regulation requiring the SPCC Compliance activities that are included in the Solid and Hazardous Waste (Line Item 1.11).

A. As I previously discussed for the Plant Smith SPCC Compliance capital project, this project is needed to help assure compliance with the revisions to the SPCC regulation, 40 CFR Part 112. These revisions 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). During 2009, Plant Smith plans to modify the drum storage secondary containment area to comply with the SPCC regulation. The estimated 2009 expenses for this project are $5,000.

Q. Mr. Vick, please describe the regulation requiring the Impaired Waters Rule (IWR) expenses that are included in the General Water Quality item (Line Item 1.6).

A. The IWR rule evaluates whether waters meet their designated uses based

on the following criteria: aquatic life use support, primary contact, recreation, fish and shellfish consumption, drinking water, and protection of human health. The FDEP has proposed listing waters in watersheds surrounding Gulf's generating facilities for nutrient and mercury impairments. The proposed IWR project will enable Gulf Power to conduct necessary modeling and evaluations to determine if Gulf's industrial wastewater discharges will contribute to any water body listings. This project will also determine whether additional wastewater reductions are required to meet new total daily maximum load requirements. The 2009 projected expenses for this project are $100,000.

Q. Please describe the O&M activities included in the air quality category that have projected expenses during 2009.

A. There are five O&M activities included in the air quality category that have projected expenses in 2009. On Schedule 2P, Air Emission Fees (Line Item 1.2), represents the expenses projected for the annual fees required by the CAAA that are payable to the FDEP and Mississippi Department of Environmental Quality. The expenses projected for the recovery period total $964,374.

Included in the air quality category, Title V (Line Item 1.3) represents projected expenses associated with the implementation of theTitle V permits. The total estimated expenses for the Title V Program during 2009 are $129,352.

On Schedule 2P, Asbestos Fees (Line Item 1.4) consists of the fees required to be paid to the FDEP for asbestos abatement projects.

The expenses projected for the recovery period total $2,500.

Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the Continuous Emission Monitoring equipment as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMs, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. Other activities within this category include the testing, development, and implementation of new compliance assurance monitoring requirements associated with the CAAA. The expenses expected to be incurred during the 2009 recovery period for these activities total $656,209.

The FDEP NOx Reduction Agreement (Line Item 1.19) includes O&M costs associated with the Plant Crist Unit 7 SCR and Crist Units 4 through 6 SNCR projects that were included as part of the 2002 agreement with FDEP. This line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the agreement. The Crist Unit 7 SCR catalyst regeneration expenses are also included in this line item. Gulf was granted approval for recovery of the costs incurred to complete these activities in FPSC Order No. PSC-02-1396-PAA-EI in Docket No. 020943-EI. The projected expenses for the 2009 recovery period total $4,168,665.

Q. What O&M activities are included in water quality category?

A. The first activity, General Water Quality (Line Item 1.6), identified in Schedule 2P, includes Soil Contamination Studies, Dechlorination, Groundwater Monitoring Plan Revisions, Surface Water Studies, the Cooling Water Intake Program, and the Impaired Waters Rule. The expenses expected to be incurred during the projection period for this line item total $556,074. This includes the projected expenses for the previously discussed Impaired Waters Rule of $100,000.

The second activity listed in the water quality category, Groundwater Contamination Investigation (Line Item 1.7), was previously approved for environmental cost recovery in Docket No. 930613-EI. This line item includes expenses related to substation investigation and remediation activities. Expenses expected to be incurred during the projection period for this line item total $1,631,176.

Line Item 1.8, State NPDES Administration, was previously approved for recovery in the ECRC and reflects expenses associated with NPDES annual and permit renewal fees for Gulf's three generating facilities in Florida. These expenses are expected to be $42,000 during the projected recovery period.

Finally, Line Item 1.9, Lead and Copper Rule, was also previously approved for ECRC recovery and reflects sampling, analytical and chemical costs related to the lead and copper drinking water quality standards. These expenses are expected to total $20,400 during the 2009 projection period.

Q. What activities are included in the environmental affairs administration Category?

A. Only one O&M activity is included in this category on Schedule 2P (Line Item 1.10) of Ms. Ritenour's exhibit. This line item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved for ECRC recovery. Expenses totaling $7,300 are expected during the 2009 recovery period.

Q. What O&M activities are included in the general solid and hazardous waste category?

A. Only one program, General Solid and Hazardous Waste (Line Item 1.11) is included in the solid and hazardous waste category on Schedule 2P. This activity involves the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This program is a previously approved program that is projected to incur incremental expenses totaling $417,471 in 2009. This line item includes $5,000 of expenses for the previously discussed SPCC compliance projects.

Q. In addition to the four major O&M categories listed above, are there any other O&M activities which have been approved for recovery that have projected expenses?

A. Yes. There are five other O&M activities that have been approved in past proceedings which have projected expenses during 2009. They are the

Above Ground Storage Tanks program, the Ash Pond Diversion Curtains, the Sodium Injection System, the CAIR/CAMR/CAVR Compliance Program, and Emission Allowances.

Q. What O&M activities are included in the Above Ground Storage Tanks line item?

A. Above Ground Storage Tanks (Line Item 1.12) includes integrity testing and maintenance activities required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. Expenses totaling $90,100 are projected to be incurred during 2009.

Q. What O&M activities are included in the Ash Pond Diversion Curtains line item?

A. The Ash Pond Diversion Curtains (Line Item 1.14) were originally approved for inclusion in the ECRC in Order No. PSC-98-1764-FOF-EI. 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. To increase retention time in the ash pond, Plant Crist plans to replace the existing ash curtains and dredge the pond during 2009. The 2009 projected expenses for this activity are $800,000.

Q. What activity is included in the Sodium Injection line item?

A. The Sodium Injection System (Line Item 1.16) was originally approved for inclusion in the ECRC in Order No. PSC-99-1954-PAA-EI. The activities in this line item involve sodium injection to the coal supply that enhances precipitator efficiencies when burning certain low sulfur coals at Plant Crist and Plant Smith. The expenses projected for the 2009 recovery period total $313,000.

Q. What activities are included in the CAIR/CAMR/CAVR Compliance Program (Line Item 1.20) activity?

A. The CAIR/CAMR/CAVR Compliance Program (Line Item 1.20) currently includes O&M expenses associated with the Crist Units 4 through 7 scrubber, the Smith Units 1 and 2 SNCRs, and the Scholz mercury monitoring project. All of these projects were included as part of the CAIR/CAMR/CAVR Compliance Program approved by the Commission on September 5, 2007. More specifically, this line item includes the cost of urea, limestone, and general operation and maintenance activities included in Gulf's CAIR/CAMR/CAVR Compliance Program. The projected expenses for the 2009 recovery period total $5,972,528.

Q. Please describe the emission allowances line items 1.29 through 1.31.

A. These line items include projected allowance expenses for Gulf's generating plants. Line Items 1.29 and 1.30 include projected expenses for annual and seasonal NOx allowances. Annual and seasonal NOx allowance expenses have been included in Gulf's 2009 projection filing

because CAIR will remain in effect unless and until the court issues a mandate in the case. The 2009 projection expenses for annual and seasonal NOx allowances are $18.6 million and $2.2 million, respectively. This projection will be updated if the CAIR is ultimately vacated. Line Item 1.31 includes $5.9 million of projected expenses for SO_2 allowances expected to be incurred during 2009 for both CAIR and Acid Rain compliance. The SO_2 expenses are offset by the amortization of gains from the sale of SO_2 allowances.

Q. Do each of the capital projects and O&M activities that have projected costs in 2009 meet the ECRC statutory guidelines?

A. Yes. The projects included in Gulf's 2009 ECRC projection filing meet the requirements of the ECRC statute and are consistent with the Commission's precedents regarding environmental cost recovery. Each of the capital projects and O&M activities set forth on Ms. Ritenour's schedules include only prudent costs incurred after April 13, 1993 that are not recovered through some other cost recovery mechanism or base rates. The projected environmental costs are necessary to achieve and/or maintain compliance with environmental laws, rules, and regulations.

Q. Mr. Vick, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 080007-EI
Date of Filing: April 2, 2008

Q. Please state your name, business address and occupation.

A. My name is Rhonda J. Martin. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Are you the same Rhonda J. Martin who has previously testified before this Commission in this on-going docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the final true-up amount for the period January 2007 through December 2007 for the Environmental Cost Recovery Clause (ECRC).

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Ms. Martin's exhibit consisting of eight schedules be marked as Exhibit No. _____(RJM-1).

Q. Are you familiar with the ECRC true-up calculation for the period January through December 2007 set forth in your exhibit?

A. Yes. These documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief the information contained in these documents is correct?

A. Yes.

Q. What is the amount to be refunded or collected in the recovery period beginning January 2009?

A. An amount to be refunded of $1,470,471 was calculated, which is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $1,470,471 to be refunded was calculated by taking the difference between the estimated January 2007 through December 2007 under-recovery of $2,117,926 as approved in FPSC Order No. PSC-07-0922-FOF-EI, dated November 16, 2007, and the actual under-recovery of $647,455, which is the sum of lines 5, 6, and 9 on Schedule 2A of my exhibit.

Q. Please describe Schedules 2A and 3A of your exhibit.

A. Schedule 2A shows the calculation of the actual under-recovery of environmental costs for the period January 2007 through December 2007. Schedule 3A of my exhibit is the calculation of the interest provision on the average true-up balance. This is the same method of calculating interest that is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

Q. Please describe Schedules 4A and 5A of your exhibit.

A. Schedule 4A compares the actual O&M expenses for the period January 2007 through December 2007 with the estimated/actual O&M expenses approved in conjunction with the November 2007 hearing. Schedule 5A shows the monthly O&M expenses by activity, along with the calculation of

jurisdictional O&M expenses for the recovery period. Emission allowance expenses and the amortization of gains on emission allowances are included with O&M expenses. Mr. Vick describes the main reasons for the variances in O&M expenses in his final true-up testimony.

Q. Please describe Schedules 6A and 7A of your exhibit.

A. Schedule 6A for the period January 2007 through December 2007 compares the actual recoverable costs related to investment with the estimated/actual amount approved in conjunction with the November 2007 hearing. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the recovery period. Recoverable costs also include a return on working capital associated with emission allowances. Schedule 7A provides the monthly recoverable costs associated with each project, along with the calculation of the jurisdictional recoverable costs. Mr. Vick describes any major variances in recoverable costs related to environmental investment for this period in his final true-up testimony.

Q. Please describe Schedule 8A of your exhibit.

A. Schedule 8A includes 28 pages that provide the monthly calculations of the recoverable costs associated with each approved capital project for the recovery period. As I stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, and the cost of emission allowances. Pages 1 through 27 of Schedule 8A show the investment and associated costs related to capital

projects, while page 28 shows the investment and costs related to emission allowances.

Q. Ms. Martin, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Susan D. Ritenour
Docket No. 080007-EI
Date of Filing: August 4, 2008

Q. Please state your name, business address and occupation.

A. My name is Susan D. Ritenour. My business address is One Energy Place, Pensacola, Florida 32520-0780. I hold the position of Secretary and Treasurer and Regulatory Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. Prior to assuming my current position, I have held various positions with Gulf including Computer Modeling Analyst, Senior Financial Analyst, Supervisor of Rate Services, and Assistant Secretary & Assistant Treasurer

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, the regulatory filing function of the Regulatory Matters Department, and various treasury and corporate secretary activities.

Q. Have you previously filed testimony before the Commission in the connection with Gulf's Environmental Cost Recovery Clause (ECRC)?

A. Yes, I have.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have. My exhibit consists of 8 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Ms. Ritenour's Exhibit consisting of 8 schedules be marked as Exhibit No. _____(SDR-2).

Q. Have you verified that to the best of your knowledge and belief the information contained in these documents is correct?

A. Yes, I have.

Q. What has Gulf calculated as the estimated true-up for the January 2008 through December 2008 period to be refunded or collected in the period January 2009 through December 2009?

A. The estimated true-up for the current period is an under-recovery of $2,810,290 as shown on Schedule 1E. This is based on six months of actual data and six months of estimated data. This amount will be netted against the 2007 final true-up over-recovery amount of $1,470,471 (see Schedule 1A to Gulf's testimony filed April 2, 2008). The sum of $1,339,819 will be collected from customers during the January 2009

through December 2009 period. The detailed calculations supporting the estimated true-up for 2008 are contained in Schedules 2E through 8E.

Q. Please describe Schedules 2E and 3E of your exhibit.

A. Schedule 2E shows the calculation of the estimated under-recovery of environmental costs for the period January 2008 through December 2008. Schedule 3E of my exhibit is the calculation of the interest provision on the average true-up balance. This is the same method of calculating interest that is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

Q. Please describe Schedules 4E and 5E of your exhibit.

A. Schedule 4E compares the estimated/actual O & M expenses for the period January 2008 through December 2008 with the projected O & M expenses approved by the Commission in conjunction with the November 2007 hearing. Schedule 5E shows the monthly O & M expenses by activity, along with the calculation of jurisdictional O & M expenses for the current recovery period. Per the Staff's request, emission allowance expenses and the amortization of gains on emission allowances are included with O & M expenses. Mr. Vick describes the main reasons for the expected variances in O & M expenses in his true-up testimony.

Q. Please describe Schedules 6E and 7E of your exhibit.

A. Schedule 6E for the period January 2008 through December 2008 compares the estimated/actual recoverable costs related to investment

with the projected amount approved in conjunction with the November 2007 hearing. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the current recovery period. Recoverable costs also include a return on working capital associated with emission allowances. Schedule 7E provides the monthly recoverable revenue requirements associated with each project, along with the calculation of the jurisdictional recoverable revenue requirements. Mr. Vick describes the major variances in recoverable costs related to environmental investment for this estimated true-up period in his testimony.

Q. Please describe Schedule 8E of your exhibit.

A. Schedule 8E includes 31 pages that provide the monthly calculations of recoverable costs associated with each approved capital investment for the current recovery period. As I stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, and the return on working capital associated with emission allowances. Pages 1 through 27 of Schedule 8E show the investment and associated costs related to capital projects, while pages 28 through 31 show the investment and return related to emission allowances.

Q. What capital structure and return on equity were used to develop the rate of return used to calculate the revenue requirements?

A. Consistent with Commission policy, the capital structure used in calculating the rate of return for recovery clause purposes is based on the capital structure approved in Gulf's last completed rate case. The rate of return for the ECRC is based on the capital structure approved in Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI dated June 10, 2002. The rate of return used to calculate ECRC revenue requirements includes a return on equity of 12.0% for the period January 1, 2008 through December 31, 2008.

Q. Ms. Ritenour, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Susan D. Ritenour
Docket No. 080007-EI
Date of Filing: August 29, 2008

Q. Please state your name, business address and occupation.

A. My name is Susan D. Ritenour. My business address is One Energy Place, Pensacola, Florida 32520-0780. I hold the position of Secretary and Treasurer and Regulatory Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. Prior to assuming my current position, I have held various positions with Gulf including Computer Modeling Analyst, Senior Financial Analyst, Supervisor of Rate Services, and Assistant Secretary & Assistant Treasurer.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, the regulatory filing function of the Regulatory Matters Department, and various treasury and corporate secretary activities.

Q. Have you previously filed testimony before the Commission in the connection with Gulf's Environmental Cost Recovery Clause (ECRC)?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present both the calculation of the revenue requirements and the development of the environmental cost recovery factors for the period of January 2009 through December 2009.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have. My exhibit consists of 7 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Ms. Ritenour's exhibit consisting of 7 schedules be marked as Exhibit No. _____ (SDR-3).

Q. What environmental costs is Gulf requesting for recovery through the Environmental Cost Recovery Clause?

A. As discussed in the testimony of J. O. Vick, Gulf is requesting recovery for certain environmental compliance operating expenses and capital costs that are consistent with both the decision of the Commission in Order No. PSC-94-0044-FOF-EI in Docket No. 930613-EI and with past proceedings in this ongoing recovery docket. The costs we have identified for recovery through the ECRC are not currently being recovered through base rates or any other cost recovery mechanism.

Q. How was the amount of projected O&M expenses to be recovered through the ECRC calculated?

A. Mr. Vick has provided me with projected recoverable O&M expenses for January 2009 through December 2009. Schedule 2P of my exhibit shows the calculation of the recoverable O&M expenses broken down between demand-related and energy-related expenses. Also, Schedule 2P provides the appropriate jurisdictional factors and amounts related to these expenses. All O&M expenses associated with compliance with the Clean Air Act Amendments of 1990 (CAAA) were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI. O&M expenses associated with Gulf's Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR) Compliance Program were considered to be energy-related pursuant to FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006. The remaining expenses were broken down between demand and energy consistent with Gulf's last approved cost-of-service methodology in Docket No. 010949-EI.

Q. Please describe Schedules 3P and 4P of your exhibit.

A. Schedule 3P summarizes the monthly recoverable revenue requirements associated with each capital investment project for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment project. These schedules also include the calculation of the jurisdictional amount of recoverable revenue requirements. Mr. Vick has provided me with the expenditures,

clearings, retirements, salvage, and cost of removal related to each capital project and the monthly costs for emission allowances. From that information, I calculated plant-in-service and construction work in progress (non interest bearing). Depreciation, amortization and dismantlement expense and the associated accumulated depreciation balances were calculated based on Gulf's approved depreciation rates, amortization periods, and dismantlement accruals. The capital projects identified for recovery through the ECRC are those environmental projects which were not included in the approved June 2002 through May 2003 test year on which present base rates were set.

Q. How was the amount of property taxes to be recovered through the ECRC derived?

A. Property taxes were calculated by applying the applicable tax rate to taxable investment. In Florida, pollution control facilities are taxed based only on their salvage value. For the recoverable environmental investment located in Florida, the amount of property taxes is estimated to be $0. In Mississippi, there is no such reduction in property taxes for pollution control facilities. Therefore, property taxes related to recoverable environmental investment at Plant Daniel are calculated by applying the applicable millage rate to the assessed value of the property.

Q. What capital structure and return on equity were used to develop the rate of return used to calculate the revenue requirements?

A. The rate of return used is based on Gulf's capital structure approved in Gulf's last rate case, Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI, dated June 10, 2002. This rate of return incorporates a return on equity of 12.0 percent.

Q. How was the breakdown between demand-related and energy-related investment costs determined?

A. The investment costs associated with compliance with the CAAA were considered to be energy-related consistent with Commission Order No. PSC-94-0044-FOF-EI, dated January 12, 1994, in Docket No. 930613-EI. The investment costs associated with Gulf's CAIR, CAMR, and CAVR Compliance Program were considered to be energy-related pursuant to FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006. The remaining investment costs of environmental compliance were allocated 12/13th based on demand and 1/13th based on energy, consistent with Gulf's last cost-of-service study. The calculation of this breakdown is shown on Schedule 4P and summarized on Schedule 3P.

Q. What is the total amount of projected recoverable costs related to the period January 2009 through December 2009?

A. The total projected jurisdictional recoverable costs for the period January 2009 through December 2009 is $84,761,585 as shown on line 1c of Schedule 1P. This includes costs related to O&M activities of

$41,015,461 and costs related to capital projects of $43,746,124 as shown on lines 1a and 1b of Schedule 1P.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2009 through December 2009 and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $86,163,397 for the period January 2009 through December 2009 as shown on line 5 of Schedule 1P. This amount includes the recoverable costs related to the projection period and the total true-up cost of $1,339,819 to be collected. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. I allocated these amounts by rate class using the appropriate energy and demand allocators as shown on Schedules 6P and 7P.

Q. How were the allocation factors calculated for use in the Environmental Cost Recovery Clause?

A. The demand allocation factors used in the ECRC were calculated using the 2006 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The energy allocation factors were calculated based on projected KWH sales for the period adjusted for losses. The calculation of the allocation factors for the period is shown in columns 1 through 9 on Schedule 6P.

Q. How were these factors applied to allocate the requested recovery amount properly to the rate classes?

A. As I described earlier in my testimony, Schedule 1P summarizes the energy and demand portions of the total requested revenue requirement. The energy-related recoverable revenue requirement of $80,165,625 for the period January 2009 through December 2009 was allocated using the energy allocator, as shown in column 3 on Schedule 7P. The demand-related recoverable revenue requirement of $5,997,772 for the period January 2009 through December 2009 was allocated using the demand allocator, as shown in column 4 on Schedule 7P. The energy-related and demand-related recoverable revenue requirements are added together to derive the total amount assigned to each rate class, as shown in column 5.

Q. What is the monthly amount related to environmental costs recovered through this factor that will be included on a residential customer's bill for 1,000 kwh?

A. The environmental costs recovered through the clause from the residential customer who uses 1,000 kwh will be $7.35 monthly for the period January 2009 through December 2009.

Q. When does Gulf propose to collect its environmental cost recovery charges?

A. The factors will be effective beginning with Cycle 1 billings in January 2009 and will continue through the last billing cycle of December 2009.

Q. Ms. Ritenour, does this conclude your testimony?

A. Yes.

MS. BROWN: Mr. Chairman, this would be a time if the Commission have any questions before we move to consider the stipulations.

CHAIRMAN CARTER: Okay. Let's take a second before we do that and get this handout passed out, and at that point in time we will recognize Commissioner Skop.

Commissioner, you're recognized.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

I apologize to my colleagues that we had to take the time to move forward with this. I had a legitimate question. And apparently in the haste to stipulate, the question that I had did not get resolved. And I am dealing with computer difficulties which makes my job a little bit more difficult, because I have it on my computer, but I have a blank screen right now. So not a perfect day.

But, anyway, the handout that Bill had just provided each of you, and hopefully Mr. Butler has a copy, I just want to come out and say I am in full support of the three solar projects that the Commission and my colleagues have approved and the cost-recovery pursuant to statute.

I do have one question with respect to a warranty provision. Again, I think that as FPL moves to mitigate their risk, equally the consumers should be protected. And if we look at the Appendix K, which is the module warranty -- and I want to commend FPL in their turnkey contract. This is a very

good one. They have gotten a very good warranty. It spans 25 years for a limited power warranty. And just briefly summarizing the warranty, it is ten-year limited product warranty where -- you know, the panels -- it is kind of like a car, they are covered completely. And then they have a limited power warranty which at year twelve, Sun Power has represented that the arrays, the solar PV arrays at the Spacecoast and DeSoto facility will meet 90 percent of the rated minimum peak power after 12 years. So that's a warranty provision that is very good.

And then the second provision in 2B, Sun Power additionally warrants that if within the first 25 years that the array will also meet 80 percent of its minimum peak power. Now, that's a very good warranty. Where I think that it has a little bit of weakness, though, is in Appendix E, and this is the credit trigger event.

And, again, I would have hoped that staff could have helped resolve this, but they didn't, so I'm having to take the time to do it here, because I believe it is a very legitimate question.

But if we would look at Appendix E and the credit trigger event, particularly Paragraph 3, and in the chart on the bottom right column. Basically, to put it in a nutshell, the warranty is only as good as Sun Power being a going concern, and this warranty spans 25 years. And I think if

history has taught us anything recently, you know, companies may be here one day and gone the next. I would cite Lehman. I would also cite the Kenotech (phonetic) bankruptcy, which I think Mr. Butler would be familiar with.

But the issue I see is that if Sun Power's tangible net worth declines, they are required to post various letters of credit as a protection pursuant to the negotiated agreement. And if you look at, again, Paragraph 3, the far right column, it lists the required stated amount after the tenth anniversary of the final acceptance date until the end of all warranty periods.

And my concern is that certainly this warranty is a very good one, but it is reasonably foreseeable that the amounts of warranty claims in the out-year period, i.e., year 12 or year 25, because of the need to meet the limited power warranty, if the solar panels degrade prematurely it would -- the expense of the warranty claim in the out-years could be that or greater than the warranty claim amounts in the near-years. So the zeros in terms of the letter of credit in the de minimis amounts, that concerned me.

Now, again, I think that the costs are prudent, but I think that it is also important to adequately protect the ratepayer so that they get the full benefit of the warranty that FPL has negotiated. So I would ask -- and I hate to put you on the spot like this, Mr. Butler. Again, I had hoped that

we would be able to resolve this, but everyone seems content on stipulating instead of answering legitimate questions. So if you might be able to comment, or is that something that given the amount of business that FPL, along with the options, has contracted with Sun Power, that they might be able to amend that to more reasonable amounts in the out-year to the extent that, you know, prior to the tenth anniversary the letter of credit amounts are significantly higher than those in the out-years.

And I would hate to get in a situation where, you know, year 20 we have a degrading array, Sun Power is financially on the ropes, and the ratepayer, you know, would be obligated to replace an array that is theoretically covered by warranty but has no effect.

So if you could briefly respond to that. I apologize, and I also apologize to my colleagues for having to take the time to resolve something that hopefully could have been resolved before we got to hearing.

MR. BUTLER: I would be happy to address your question, Commissioner Skop.

One thing I will observe, and I will be somewhat vague in the responses because much of this information is confidential and I don't want to end up making it more public than necessary.

COMMISSIONER SKOP: Okay. Let me stop you there,

because, again, the document that I have -- and, again, I see two different versions floating around, but the document I have is not stamped confidential. And hopefully I didn't disclose any confidential information. I think I referred to it generically. But, if I have, I apologize, and that is due to the document that was provided to me.

MR. BUTLER: I think we are fine, but I just wanted to preface it so that you would understand why my responses may be not as specific as they would otherwise. FPL has negotiated and worked diligently with Sun Power to get the warranty protections and the backup, the financial backup to those warranty protections that are here. It is substantially beyond what -- as I understand it, what Sun Power would ordinarily be providing. And, you know, FPL has deliberately chosen Sun Power in large measure because it is, you know, one of the largest, most experienced, and best capitalized companies in the solar business. It really stands out significantly from a lot of the other sort of newer and more start-up entities that are in this business.

The protection -- the warranty structure, to try to answer your question directly, you know, it divides into two basic pieces. There is a piece that is in place for the first period of time you mentioned for ten years that is directed at warranting, essentially, the entire operation of the project, and then that changes after ten years to a warranty that is

particularly on what is referred to as the modules, and it is referring to the individual solar panels.

You know, two things that FPL has seen. First of all, the experience in the industry has been that if the panels fail, you know, they are mechanically operating components, it is basically a large silicone wafer, that is something that very significantly or substantially occurs in the early years of operation, not later once they have been in service for an extended period of time. And so the real expectation, if we have problems with the panels, is that they would be in the earliest years when the warranty protection and the sort of financial integrity assurances are the greatest.

In the later years, you are right that the protection isn't as substantial. That is based on FPL's evaluation, working with Sun Power, observing the industry experience that is now over 20 years old with the operation of these silicone wafer photovoltaic modules that they are a very low probability of failing. If one fails, what you do is you replace that one. There are for the DeSoto project something like 90,000 of the panels. I think it is something like 35,000 for the Spacecoast project. They only cost to remove and replace about $4,000 each. So you could end up having quite a few panels failing. You would simply go in -- or degrading -- you would simply go in and replace the ones that are there and go about the business.

It is fundamentally different, I think, from something like say, you know, turbine blades failing in a gas turbine where you can't use the unit until you have everything back in order, and that probably if you have a failure are likely to be dealing with a very large expensive piece of equipment.

So, fundamentally, the response is that the warranties were structured to provide the greatest protection in the earlier years when the perception was that the potential of system problems was the greatest, to have the financial integrity track that greatest period of warranty liability. It is not as great at the back end because that's what FPL was able to negotiate.

The letters of credit are expensive. And, obviously, if we negotiate more protection from letters of credit, particularly out so far in time, we would expect to have to be compensating the vendor accordingly. This was the compromise FPL reached that seemed to provide the best protection at the fairest price.

COMMISSIONER SKOP: Thank you, Mr. Butler.

And, again, I appreciate that explanation. But, you know, the concern I have -- again, I agree with you wholeheartedly that if you are going to have a failure, just as any piece of electronic component, a failure of the system, you should see that early on. But Florida has harsh environmental

conditions. A concern that has been widely expressed by many people that I have spoken to has been the long-term degradation of the efficiency of each individual module, and that could be a realistic problem in the out-years.

I'm not saying that it is or isn't. Again, we'll have to wait 25 years to see that. But at the end of the day, again, making sure the consumer is adequately protected, because they are the ones, pursuant to the legislative direction, that have been required to pay for this, and you guys have full cost recovery -- and, again, I commend FPL on the warranty. It is one of the best I have seen. But, again, it loses some of its teeth in the out-years. And to put that into perspective, you mentioned the number of modules that were in each of the respective arrays. That $500,000 letter of credit would only buy 125 modules.

So, again, you know, it's a concern in passing, but I think it is a valid concern. I mean, each of these arrays are -- the number is probably confidential. I'm not sure whether it is or not, but they are very expensive pieces of equipment. And, again, if they were to fail or degrade sufficiently, which we don't know, I mean, Sun Power has been in business for 20 years. I have read their company history. But, you know, should the consumer bear that additional risk, because I don't think that if 15 years, 25 years down the line if Sun Power is not in business, and we come to FPL and we say

are you going to step into the shoes? I don't think you guys would be willing to do that.

So, again, my concern. I recognize letter of credits are very important, but I just think that for what -- for the excellent job that they did on negotiating the warranty, if the numbers in that far right column would be a little bit different I would feel a little bit more comfortable.

MR. BUTLER: I understand, I think we all would. The challenge is that letters of credit are excellent protection, they are also quite expensive, and this was FPL's judgment as the best compromise. That if we had insisted on a larger volume and longer lasting letters of credit, it would have come at a price. FPL's assessment of the experience in the industry is that there isn't a traditionary history of kind of common failure mode problems degrading these modules. So the sense was that we were looking at protection against the sort of odd module failing as opposed to -- or degrading -- as opposed to something that was a blanket issue.

If it turns out that is not right, that there is some widespread problem, and it has to be coupled with Sun Power being an extremely well capitalized, large, substantial firm with a lot of history getting into severe financial difficulty, then obviously we could find ourselves in a position where we wished we had had more in the way of letters of credit.

But, by the same token, if that doesn't happen and we

paid much, much more money for that protection and it never ended up being used, then we would wish we hadn't put so much money into letters of credit. And this is what FPL saw as being the best balance between what are admittedly competing considerations in trying to decide what the right level of contract protection is.

COMMISSIONER SKOP: Okay. And, like I say, I respect that. Again, I think I would feel a little bit more comfortable if the out-year numbers were a little bit more substantial. I guess the issue before the Commission is obviously cost-recovery, not necessarily review of the warranty, but the way that this is all come before us this is the first time that the Commission has actually had the opportunity to review, you know, the underlying contracts, the warranty, and the land purchase -- I mean, the land lease and all those other things.

So, again, that was just one point in passing that, you know, I wanted to raise to FPL. It is a legitimate question. It is remote and attenuated that we would ever find ourselves in that position, but if all those -- if we go down that path and certain things happen, you know, Sun Power goes out the business, you know, obviously we don't have full protection to otherwise enforce a warranty or mitigate the impact to the ratepayer as a result of not having, you know, standing letters of credit if the company were to decline in

their net worth substantially. So, thank you.

CHAIRMAN CARTER: Thank you, Commissioner.

Commissioners, let's do this. Let's take about -- I'm looking at the clock to my right. We will come back at 25 after. We'll take a brief recess.

(Recess.)

CHAIRMAN CARTER: We are back on the record.

And we took a break as we were going through a question.

Commissioner Skop, sir, you're recognized.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

And I just want to clarify a previous remark that I made. I know that our hard-working staff is really busy and has been working very had on all these dockets. But, you know, as a Commissioner, you know, I asked a legitimate question and it did not get answered prior to coming today.

So, again, my comments are not directed in any way towards the bench. But, again, as a Commissioner, again, I feel that this is a very legitimate question. You know, we have an excellent warranty, but all I was merely trying to articulate was that now that I have my computer in front of me halfway working, that the warranty is a very good one, but what I see is that the protection breaks down with a contracting weakness in Appendix E. So --

CHAIRMAN CARTER: Thank you.

Commissioner Argenziano.

COMMISSIONER ARGENZIANO: You know, as an individual Commissioner, what I detect from Commissioner Skop is he feels he needs to apologize for asking a question, and I'm here to tell you, just as a colleague of yours, you never have to apologize for asking a question. That's what we are all here for. So if you have a legitimate question -- and knowing staff, we are swamped here at the PSC, so things are going to happen. We are going to ask things the wrong way. They are swamped with all kinds of things that they need to take care of. It's going to happen. So I don't think you need to apologize for any question you have to ask.

CHAIRMAN CARTER: Thank you, Commissioners.

Anything further from the bench?

Staff, you're recognized.

MS. BROWN: Mr. Chairman, since the parties are proposing stipulations on all the issues, I would note that OPC has taken no position. We suggest that the Commission could make a bench decision in the case.

CHAIRMAN CARTER: Commissioners, we have had a proposed stipulation for the testimony. We did enter the testimony, did we not?

MS. BROWN: Yes.

CHAIRMAN CARTER: And the exhibits, we did enter the exhibits?

MS. BROWN: Yes.

CHAIRMAN CARTER: And at this point in time the staff is recommending that we accept the stipulation. Commissioners, if there is any further discussion on anything to be heard on prior to moving forward?

Hearing none. The chair is now open for a motion.

Commissioner Edgar, you're recognized.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I would make a motion that we adopt the stipulations in the 07 environmental cost-recovery docket.

COMMISSIONER SKOP: Second.

CHAIRMAN CARTER: Moved and properly seconded.

Commissioners, any questions, any concerns, any debate?

Hearing none. All those in favor, let it be known by the sign of aye.

(Simultaneous aye.)

CHAIRMAN CARTER: All those opposed, like sign. Show it done.

Commissioners, as we get prepared for your next --

MS. BROWN: Mr. Chairman, if I just might mention --

CHAIRMAN CARTER: You're recognized.

MS. BROWN: -- since the Commission has made a bench decision, the final order in the case will be issued by November 24th.

CHAIRMAN CARTER: And that's on Docket Number 080007-EI.

* * * * * * *

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

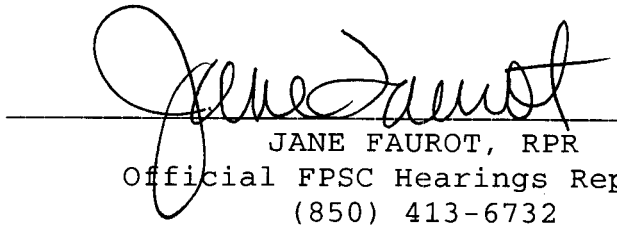
COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 14th day of November, 2008.



JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
Staff				
1		Exhibit List - 1	Comprehensive Exhibit List	
2		Staff's Composite Exhibit – 2 stipulated	**Florida Power & Light** 1. FPL's Response to Staff's 2nd Request for Production of Documents (No. 3) *[Bates Nos. 00000001-00000003* 2. FPL's Response to Staff's 4th Request for Production of Documents (No. 7) *[Bates Nos. 00000004-00000008]* 3. FPL's Response to Staff's 4th Request for Production of Documents (No. 9) *[Bates Nos. 00000009-000000010]* 4. FPL's Response to Staff's 4th Request for Production of Documents (No. 12) *[Bates Nos. 000000011-00000470]* 5. FPL's Response to Staff's 4th Request for Production of Documents (No. 14) *[Bates Nos. 00000471-00000559]* 6. FPL's Response to Staff's 4th Request for Production of Documents (No. 17) *[Bates Nos. 00000560-00000562]*	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 1
COMPANY FL Public Sevice Comm. Staff
WITNESS Exhibit List-1
DATE 11-04-0

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
			7. FPL's Response to Staff's 5th Request for Production of Documents (No. 23) *[Bates Nos. 00000563-00000565]* 8. FPL's Response to Staff's 5th Request for Production of Documents (No. 25) *[Bates Nos. 00000566-00000599]* 9. FPL's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 15) *[Bates Nos. 00000600-00000618]* 10. FPL's Response to Staff's 2nd Set of Interrogatories (Nos. 16 - 17) *[Bates Nos. 00000619-00000623]* 11. FPL's Response to Staff's 3rd Set of Interrogatories (No. 18 - 33) *[Bates Nos. 00000624-00000643]* 12. FPL's Response to Staff's 4th Set of Interrogatories (Nos. 34 - 45) *[Bates Nos. 00000644-00000668]* 13. FPL's Response to Staff's 5th Set of Interrogatories (Nos. 46 – 48) *[Bates Nos. 00000669-00000672]* 14. FPL's Response to Staff's 6th Set of Interrogatories (Nos. 49 – 50) *[Bates Nos. 00000673-00000676]*	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D.#	Witness	I.D. # As Filed	Exhibit Description	Entered
			15. FPL's Response to Staff's 7th Set of Interrogatories (No. 51) *[Bates Nos. 00000677-00000681]* 16. FPL's Response to Staff's 8th Set of Interrogatories (Nos. 52 – 56) *[Bates Nos. 00000682-00000691]* **Progress Energy Florida** 17. PEF's Response to Staff's 2nd Request for Production of Documents (No. 2) *[Bates Nos. 00000692-00000699]* 18. PEF's Response to Staff's 3rd Request for Production of Documents (No. 3) *[Bates Nos. 00000700-00000730]* 19. PEF's Response to Staff's 4th Request for Production of Documents (Nos. 5 – 6) *[Bates Nos. 00000731-00000759]* 20. PEF's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 4) *[Bates Nos. 00000760-00000765]* 21. PEF's Response to Staff's 2nd Set of Interrogatories (Nos. 5 – 7) *[Bates Nos. 00000766-00000778]* 22. PEF's Response to Staff's 3rd Set of Interrogatories (No. 8) *[Bates Nos. 00000779-00000781]*	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
			23. PEF's Response to Staff's 4th Set of Interrogatories (Nos. 9 – 18) *[Bates Nos. 00000782-00000796]* 24. PEF's Response to Staff's 5th Set of Interrogatories (Nos. 19 – 25) *[Bates Nos. 00000797-00000805]* 25. PEF's Response to Staff's 6th Set of Interrogatories (No. 26) *[Bates Nos. 00000806-00000811]* **Gulf Power Company** 26. Gulf's Response to Staff's 1st Request for Production of Documents (No. 1) *[Bates Nos. 00000812-00000814]* 27. Gulf's Response to Staff's 2nd Request for Production of Documents (Nos. 2 - 5) *[Bates Nos. 00000815-00000902]* 28. Gulf's Response to Staff's 3rd Request for Production of Documents (No. 6) *[Bates Nos. 00000903-00000905]* 29. Gulf's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 3) *[Bates Nos. 00000906-00000909]* **Tampa Electric Company** 30. TECO's Response to Staff's 2nd Request for Production of Documents (No. 2) *[Bates Nos. 00000910-00000918]*	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			31. TECO's Response to Staff's 4th Request for Production of Documents (No. 4) *[Bates Nos. 00000919-00000922]* 32. TECO's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 2) *[Bates Nos. 00000923-00000930]* 33. TECO's Response to Staff's 2nd Set of Interrogatories (No. 3) *[Bates Nos. 00000931-00000932]* 34. TECO's Response to Staff's 3rd Set of Interrogatories (Nos. 4 – 7) *[Bates Nos. 00000933-00000961]* 35. TECO's Revised Form 42 – 1P, 10/17/08 *[Bates Nos. 00000962-00000963]* 36. TECO's 2009 Projection Schedules *[Bates Nos. 00000964-00000966]*	
Florida Power & Light Company (Direct)				
3	Korel M. Dubin	KMD-1	Appendix I Environmental Cost Recovery Final True-up January - December 2007 Commission Forms 42-1A through 42-8A	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
4	Korel M. Dubin	KMD-2	Appendix I: Environmental Cost Recovery Estimated/Actual Period January-December 2008 Commission Forms 42-1E through 42-8E	
5	Korel M. Dubin	KMD-3	Appendix I: Environmental Cost Recovery Projections January – December 2009 Commission Forms 42-1P through 42-7P	
6	R. R. Labauve	RRL-1	FPL's Supplemental CAIR/CAMR/CAVR Filing	
7	R. R. Labauve	RRL-2	Executive Order 07-127	
8	R. R. Labauve	RRL-3	HB 7135	
9	E. Silagy	ES-1	Martin Solar Project Milestones	
10	E. Silagy	ES-2	Desoto Solar Project Milestones	
11	E. Silagy	ES-3	Space Coast Solar Project Milestones	
Progress Energy Florida, Inc. (Direct)				
12	Will Garrett	WG-1	PSC Forms 42-1A through 42-8A, January 2007 – December 2007	
13	Will Garrett	WG-2	Capital Program Detail January 2008 – December 2008	
14	Patricia Q. West	PQW-1	**CONFIDENTIAL** Review of PEF's Integrated Clean Air Compliance Plan - 4/2/08	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
15	Dale Wilterdink	DW-1	Crystal River Project Organizational Structure	
16	Lori Cross	LC-1	PSC Forms 42-1E through 42-8E, January 2008 – December 2008	
17	Lori Cross	LC-2	Capital Program Detail January 2008 – December 2008	
18	Lori Cross	LC-3	PSC Forms 42-IP through 42-7P, January 2009 – December 2009	
19	Lori Cross	LC-4	Capital Program Detail January 2009 – December 2009	
Tampa Electric Company (Direct)				
20	Howard T. Bryant	HTB-1	Final Environmental Cost Recovery Commission Forms 42-1A through 42-8A for the period January 2007 through December 2007	
21	Howard T. Bryant	HTB-2	Environmental Cost Recovery Commission Forms 42-1E through 42-8E for the period January 2008 through December 2008	
22	Howard T. Bryant	HTB-3	Environmental Cost Recovery Commission Forms 42-1P through 42-7P for the period January 2009 through December 2009	
Gulf Power Company (Direct)				
23	James O. Vick	JOV-1	FDEP Letter of Clarification	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
24	James O. Vick	JOV-2	2009 Projection Filing – Plant Crist Consumptive Use Permit; NWFWMD correspondence to Gulf Power dated July 3, 2008	
25	Rhonda J. Martin The prefiled exhibit of Rhonda J. Martin will be adopted by Susan Ritenour.	RJM-1	Calculation of Final True-up 1/07 – 12/07	
26	Susan Ritenour (Adopts Martin)	SDR-2	Calculation of Estimated True-up 1/08 – 12/08	
27	Susan Ritenour (Adopts Martin)	SDR-3	Calculation of Projection 1/09 - 12/09	

HEARING EXHIBITS				
Exhibit Number	**Witness**	**Party**	**Description**	**Moved In/Due Date of Late Filed**
28				
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HEARING EXHIBITS				
Exhibit Number	**Witness**	**Party**	**Description**	**Moved In/Due Date of Late Filed**
33				
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HEARING EXHIBITS				
Exhibit Number	**Witness**	**Party**	**Description**	**Moved In/Due Date of Late Filed**
45				
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51				
52				

EXHIBIT NO. _____

DOCKET NO: 080007-EI

WITNESSES: VARIOUS

PARTIES: FLORIDA POWER & LIGHT CO.; PROGRESS ENERGY FLORIDA; GULF POWER COMPANY; and TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT-2 OF STIPULATED **(Redacted)** DOCUMENTS

Florida Power & Light

1. FPL's Response to Staff's 2nd Request for Production of Documents (No. 3) *[Bates Nos. 00000001-00000003*
2. FPL's Response to Staff's 4th Request for Production of Documents (No. 7) *[Bates Nos. 00000004-00000008]*
3. FPL's Response to Staff's 4th Request for Production of Documents (No. 9) *[Bates Nos. 00000009-000000010]*
4. FPL's Response to Staff's 4th Request for Production of Documents (No. 12) *[Bates Nos. 000000011-00000470]*
5. FPL's Response to Staff's 4th Request for Production of Documents (No. 14) *[Bates Nos. 00000471-00000559]*
6. FPL's Response to Staff's 4th Request for Production of Documents (No. 17) *[Bates Nos. 00000560-00000562]*
7. FPL's Response to Staff's 5th Request for Production of Documents (No. 23) *[Bates Nos. 00000563-00000565]*
8. FPL's Response to Staff's 5th Request for Production of Documents (No. 25) *[Bates Nos. 00000566-00000599]*
9. FPL's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 15) *[Bates Nos. 00000600-00000618]*
10. FPL's Response to Staff's 2nd Set of Interrogatories (Nos. 16 - 17) *[Bates Nos. 00000619-00000623]*
11. FPL's Response to Staff's 3rd Set of Interrogatories (No. 18 - 33) *[Bates Nos. 00000624-00000643]*
12. FPL's Response to Staff's 4th Set of Interrogatories (Nos. 34 - 45) *[Bates Nos. 00000644-00000668]*

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 2
COMPANY FL PSC Staff
WITNESS Staff's Composite Ex-2 Stipulated
DATE 11-04-08

13. FPL's Response to Staff's 5th Set of Interrogatories (Nos. 46 – 48) *[Bates Nos. 00000669-00000672]*

14. FPL's Response to Staff's 6th Set of Interrogatories (Nos. 49 – 50) *[Bates Nos. 00000673-00000676]*

15. FPL's Response to Staff's 7th Set of Interrogatories (No. 51) *[Bates Nos. 00000677-00000681]*

16. FPL's Response to Staff's 8th Set of Interrogatories (Nos. 52 – 56) *[Bates Nos. 00000682-00000691]*

Progress Energy Florida

17. PEF's Response to Staff's 2nd Request for Production of Documents (No. 2) *[Bates Nos. 00000692-00000699]*

18. PEF's Response to Staff's 3rd Request for Production of Documents (No. 3) *[Bates Nos. 00000700-00000730]*

19. PEF's Response to Staff's 4th Request for Production of Documents (Nos. 5 – 6) *[Bates Nos. 00000731-00000759]*

20. PEF's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 4) *[Bates Nos. 00000760-00000765]*

21. PEF's Response to Staff's 2nd Set of Interrogatories (Nos. 5 – 7) *[Bates Nos. 00000766-00000778]*

22. PEF's Response to Staff's 3rd Set of Interrogatories (No. 8) *[Bates Nos. 00000779-00000781]*

23. PEF's Response to Staff's 4th Set of Interrogatories (Nos. 9 – 18) *[Bates Nos. 00000782-00000796]*

24. PEF's Response to Staff's 5th Set of Interrogatories (Nos. 19 – 25) *[Bates Nos. 00000797-00000805]*

25. PEF's Response to Staff's 6th Set of Interrogatories (No. 26) *[Bates Nos. 00000806-00000811]*

Gulf Power Company

26. Gulf's Response to Staff's 1st Request for Production of Documents (No. 1) *[Bates Nos. 00000812-00000814]*

27. Gulf's Response to Staff's 2nd Request for Production of Documents (Nos. 2 - 5) *[Bates Nos. 00000815-00000902]*

28. Gulf's Response to Staff's 3rd Request for Production of Documents (No. 6) *[Bates Nos. 00000903-00000905]*

29. Gulf's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 3) *[Bates Nos. 00000906-00000909]*

Tampa Electric Company

30. TECO's Response to Staff's 2nd Request for Production of Documents (No. 2) *[Bates Nos. 00000910-00000918]*

31. TECO's Response to Staff's 4th Request for Production of Documents (No. 4) *[Bates Nos. 00000919-00000922]*

32. TECO's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 2) *[Bates Nos. 00000923-00000930]*

33. TECO's Response to Staff's 2nd Set of Interrogatories (No. 3) *[Bates Nos. 00000931-00000932]*

34. TECO's Response to Staff's 3rd Set of Interrogatories (Nos. 4 – 7) *[Bates Nos. 00000933-00000961]*

35. TECO's Revised Form 42 – 1P, 10/17/08 *[Bates Nos. 00000962-00000963]*

36. TECO's 2009 Projection Schedules *[Bates Nos. 00000964-00000966]*

PROFFERED BY: STAFF

1

FPL's Response to Staff's Second Request for Production of Documents (No. 3)

HEARING EXHIBIT - 00000001

Q.

Referring to the testimony of K.M. Dubin dated April 2, 2008, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-8A attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

A.

The "Equity Component" and "Debt Component" that make up the Return on Average Net Investment (Form 42-8A, Lines 7a and 7b) are derived as follows: Attachment I shows an annual "total equity" component of 5.6640% and annual "total debt" component of 1.8767% These annual return components are divided by 12 to get monthly return components. These monthly return components are then multiplied times the "Average Net Investment" amount shown on line 6 of Form 42-8A for each month. In the case of the "Equity Component," the resulting amount is then also divided by the "gross-up for taxes" factor of 0.61452 stated in Note D to Form 42-8A

Attachment I is provided as Bates No. ECRC 08-109

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES
ACTUAL COST RATES TO BE USED FOR JANUARY THROUGH DECEMBER 2006 ACTUALS

Equity @ 11.75%

CAPITAL STRUCTURE AND COST RATES PER 12/31/2006 SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	3,486,292,100	26.413%	5.539%	1.4630%	1.4630%
SHORT TERM DEBT	643,567,393	4.876%	4.576%	0.2231%	0.2231%
PREFERRED STOCK	0	0.000%	0.000%	0.0000%	0.0000%
CUSTOMER DEPOSITS	406,209,278	3.077%	5 963%	0.1835%	0.1835%
COMMON EQUITY	6,331,842,680	47.971%	11.750%	5.6366%	9.1763%
DEFERRED INCOME TAX	2,283,698,536	17.302%	0 000%	0.0000%	0.0000%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0 000%	0.0000%	0.0000%
WEIGHTED COST	47,778,535	0.362%	9 545%	0.0345%	0.0518%
			0		
TOTAL	$13,199,388,522	100.00%		7.541%	11.10%

CALCULATION OF THE WEIGHTED COST FOR INVESTMENT TAX CREDITS (b)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	
LONG TERM DEBT	$3,486,292,100	35.51%	5.54%	1.97%	1.97%
PREFERRED STOCK	0	0.00%	0 00%	0.00%	0.00%
COMMON EQUITY	6,331,842,680	64.49%	11.75%	7.58%	12.34%
TOTAL	$9,818,134,780	100.00%		9.54%	14.30%
RATIO					0.36%
					0.05%

DEBT COMPONENTS:	
LONG TERM DEBT	1.4630%
SHORT TERM DEBT	0.2231%
CUSTOMER DEPOSITS	0.1835%
TAX CREDITS -WEIGHTED	0 0071%
TOTAL DEBT	**1.8767%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	5 6366%
TAX CREDITS -WEIGHTED	0.0274%
TOTAL EQUITY	**5.6640%**
TOTAL	7.5407%
PRE-TAX EQUITY	9.2210%
PRE-TAX TOTAL	11.0977%

HEARING EXHIBIT - 00000003

2

FPL's Response to Staff's Fourth Request for Production of Documents (No. 7)

Q.
For each RFP issued for FPL's three Solar Energy Projects, please provide documents showing the list of all entities receiving the RFP.

A. Documents responsive to this request are provided as Bates Nos. ECRC 08-191 through ECRC 08-192.

Please see the following list of suppliers that received RFPs relating to DeSoto Solar and Space Coast Solar.

Puchase Order	Supplier 1	Supplier 2	Supplier 3	Supplier 3
4500441438	Al Budnick	N/A	N/A	N/A
4500435701	Archaeological & Historical Conservancy	N/A	N/A	N/A
4500424565	Boyle Engineering	WilsonMiller	N/A	N/A
4500426091	Boyle Engineering	Tetra Tech	N/A	N/A
4500430378	Boyle Engineering	WilsonMiller	N/A	N/A
4500433890	Boyle Engineering	N/A	N/A	N/A
CO#1 - 4500424565	Boyle Engineering	N/A	N/A	N/A
CO#1 - 4500430378	Boyle Engineering	N/A	N/A	N/A
CO#2 - 4500424565	Boyle Engineering	N/A	N/A	N/A
4500402410	Ecology & Environment	Pandion	ERM	Dynamac
4500409017	Golder Associates	N/A	N/A	N/A
4500425401	Golder Associates	N/A	N/A	N/A
4500424582	P & E Engineering	N/A	N/A	N/A
4500393475	Pandion Systems, Inc	N/A	N/A	N/A
4600003866	SF Holden	N/A	N/A	N/A
4500411801	WilsonMiller	N/A	N/A	N/A
4500433882	WilsonMiller	N/A	N/A	N/A
CO 4500411801	WilsonMiller	N/A	N/A	N/A
CO 4500411801	WilsonMiller	N/A	N/A	N/A
CO 4500411801	WilsonMiller	N/A	N/A	N/A

Please see the following list of suppliers that received RFPs relating to Martin Solar.

Description	Supplier(s)
Conceptual Design	WorleyParsons
EPCM	MSM
Modification Site Certification	Golder Associates
SCA	Flagsol, Gossamer, SENER
Solar Meter	Augustyn & Company
Species Survey	Golder Associates
Steam Side	Black & Veatch
Stormwater Design	Boyle Engineering
Topographic Survey	Boyle Engineering
Tubes	Schott

SOLAR PV BIDDERS LIST

First Solar
400 Somerset Corporate Blvd.
Suite 501
Bridgewater, NJ 08807
Contact: Bruce Curtis
Tel: 908-526-7900 ext. 113
Fax: 908-526-7906
Cell: 732-489-6144

Fotowatio USA
International Square Bld.
Suite 501-502
1875 I Street, N.W.
Washington, D.C. 2006
Contact: Diego Belmonte
Tel: 202-775-4937
diego.belmonte@fotowatiousa.com

Sharp Electronics Corporation
5901 Bolsa Avenue
Huntington Beach, CA 92647
Tel: 714-903-5030
Fax: 714-903-4858
Contact: Dick Lowry
LowryD@sharpsec.com

Solar World
9858 Glades Rd. #700
Boca Raton, FL 33434
Contact: Peter DeNapoli
Tel: 561-477-7679
Fax: 561-477-7617
Cell: 561-289-0232
peter.denapoli@solarworld-usa.com

Sun Edison
12500 Baltimore Avenue
Beltsville, MD 20705
Tel: 443-909-7200 ext 1265
Fax: 443-909-7166
Cell: 410-375-9420
Contact: Frances Yuhas
fyuhas@sunedison.com

Sunpower Systems
2954 San Pablo Avenue
Berkeley CA 94072
Contact: Geoff Wilcox and Ed Smeloff
Tel: 510-868-1380 Geoff
Tel: 510-289-9082 Ed
esmeloff@sunpowercorp.com
geoff.wilcox@sunpowercorp.com

GE
David Swanson
Tel: 561-624-8179
david1.swanson@ge.com

Schott
Casey Gutowski
Director of Business Development
SCHOTT Solar, Inc.
916-774-3012 V
559-999-1127 C
916-784-9781 F
casey.gutowski@us.schott.com
www.us.schott.com

3

FPL's Response to Staff's Fourth Request for Production of Documents (No. 9)

Q.

Please provide a copy of all documents showing FPL's evaluation of the RFP Responses received relative to each of FPL's three Solar Energy Projects.

A.

Confidential documents responsive to this request are provided as Bates Nos. ECRC 08-545 through ECRC 08-581, ECRC 08-1580 through ECRC 08-1582, ECRC 08-1585 through ECRC 08-1598, ECRC 08-1600 through ECRC 08-1607, ECRC 08-1610 through ECRC 08-1613, ECRC 08-1615 through 08-1621, ECRC 08-1623, ECRC 08-1625 through ECRC 08-1656, ECRC 08-1659 through ECRC 08-1664, ECRC 08-1667 through ECRC 08-1700, ECRC 08-1683 through ECRC 08-1700, ECRC 08-1702 through 08-1703, ECRC 08-1705 through 08-1707, ECRC 08-1709 through ECRC 08-1715, ECRC 08-2815 through ECRC 08-2829, ECRC 08-4344, ECRC 08-8119, ECRC 08-8122

Non confidential documents responsive to this request are provided as Bates Nos. ECRC 08-1583 through 08-1584, ECRC 08-1599, ECRC 08-1608 through 08-1609, ECRC 08-1614, ECRC 08-1622, ECRC 08-1624, ECRC 08-1657, ECRC 08-1658, ECRC 08-1665 through ECRC 08-1666, ECRC 08-1701, 08-1704, ECRC 08-1708, ECRC 08-1716 , ECRC 08-8120 through ECRC 08-8121 and ECRC 08-8123 through ECRC 08-8125

4

FPL's Response to Staff's Fourth Request for Production of Documents (No. 12)

Q.

Please provide a copy of the following:

a. **Contracts, agreements, letters, and memoranda involving SunPower Company as related to DeSoto Solar Energy Center and Space Coast Solar Energy Center.**

b. **Any and all other contracts, agreements, letters, and memoranda in FPL's possession related to the DeSoto and Space Coast Solar projects.**

A.

A.

responsive to this request are provided as Bates Nos. ECRC 08-2832 through ECRC 08-2835, ECRC 08-2886, ECRC 08-2901 through ECRC 08-2902, ECRC 08-2904 through ECRC 08-2906, ECRC 08-2991, ECRC 08-3022 through ECRC 08-3147, ECRC 08-3202 through ECRC 08-3202 through ECRC 08-3214, ECRC 08-3265, ECRC 08-3268 through ECRC 08-3268, ECRC 08-3279 through ECRC 08-3285, ECRC 08-3367, ECRC 08-3369, ECRC 08-3392 through 08-ECRC 08-3393, ECRC 08-3398 through ECRC 08-3464 and ECRC 08-3521 through ECRC 08-3529.

Non Confidential documents responsive to this request are provided as Bates Nos. ECRC 08-582 through ECRC 08-765, ECRC 08-2836 through ECRC 08-2885, ECRC 08-2887 through ECRC 08-2888, ECRC 08-2890 through ECRC 08-2899, ECRC 08-2903, ECRC 08-2907 through ECRC 08-2990, ECRC 08-2992 through ECRC 08-3020, ECRC 08-3148 through ECRC 08-3201, ECRC 08-3215 through 08-3264, ECRC 08-3266 through ECRC 08-3267, ECRC 08-3269 through 08-3277, ECRC 08-3282, ECRC 08-3286 through ECRC 08-3366, ECRC 08-3368, ECRC 08-3370 through 08-3391, ECRC 08-3394 through ECRC 08-3397, ECRC 08-3465 through ECRC 08-3467 and ECRC 08-3469 through ECRC 08-3520.

B

Confidential documents responsive to this request are provided as Bates Nos. ECRC 08-1717 through ECRC 08-1721, ECRC 08-1740 through ECRC 08-1745, ECRC 08-1764 through ECRC 08-1770, ECRC 08-1787 through ECRC 08-1796, ECRC 08-1811 ECRC 08-1814, ECRC 08-4399 through 08-4435, ECRC 08-4437 through ECRC 08-4441, ECRC 08-4445 through ECRC 08-4447, ECRC 08-4458 through ECRC 08-4466, ECRC 08-4469 through ECRC 08-4485, ECRC 08-4506 through ECRC 08-4511, ECRC 08-4530 through ECRC 08-4534, ECRC 08-4541 through 08-4548 and ECRC 08-4566 through ECRC 08-4573

Non Confidential documents responsive to this request are provided as Bates Nos. ECRC 08-1722 through ECRC 08-1739, ECRC 08-1746 through ECRC 08-1763, ECRC 08-1771 through ECRC 08-1786, ECRC 08-1797 through ECRC 08-1810, ECRC 08-1815 through ECRC 08-1830, ECRC 08-4345 through ECRC 08-4398, ECRC 08-4436, ECRC 08-4442 through ECRC 08-4444, ECRC 08-4448 through 08-4457, ECRC 08-4467 through ECRC 08-4468, ECRC 08-4486 through ECRC 08-4505, ECRC 08-4512 through ECRC 08-4529, ECRC 08-4535 through ECRC 08-4540, ECRC 08-4549 through ECRC 08-4565 and ECRC 08-4574 through 08-4585.

TURNKEY

ENGINEERING, PROCUREMENT AND CONSTRUCTION

AGREEMENT

FOR

SOLAR PHOTOVOLTAIC GENERATING FACILITY

BETWEEN

FLORIDA POWER & LIGHT COMPANY,
as FPL

AND

SUNPOWER CORPORATION, SYSTEMS,
as Contractor

Dated as of July 3, 2008

TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION

AGREEMENT FOR

SOLAR PHOTOVOLTAIC GENERATING FACILITY

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ECRC-08-2841 HEARING EXHIBIT - 00000019

TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT FOR SOLAR PHOTOVOLTAIC GENERATING FACILITY

THIS TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT FOR SOLAR PHOTOVOLTAIC GENERATING FACILITY (this "Agreement"), dated as of July 3, 2008, is by and between FLORIDA POWER & LIGHT COMPANY, a Florida corporation (hereinafter called "FPL") and SunPower Corporation, Systems, a Delaware corporation (hereinafter called "Contractor").

WITNESSETH:

WHEREAS, FPL wishes to construct and operate a solar photovoltaic generation facility with a minimum nominal capacity of 25 MW (net), and all services and utilities related thereto, all to be built on the Property Site (as hereinafter defined) located in DeSoto County, Florida;

WHEREAS, Contractor has represented that it is experienced and qualified in providing technical assistance, licensing, engineering, procurement, supply, construction management, construction, commissioning, start-up and testing services, and that it possesses the requisite expertise and resources to complete the Work (as hereinafter defined);

WHEREAS, Contractor has agreed to provide, through itself or through Subcontractors and Vendors (as such terms are hereinafter defined), such Work on a "turn-key" basis for the Contract Price (as hereinafter defined); and

WHEREAS, Contractor has agreed to guarantee the timely and proper completion of the Work in strict accordance with the terms and conditions hereinafter set forth.

NOW, THEREFORE, in consideration of the foregoing premises, the mutual promises and covenants herein contained, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, FPL and Contractor hereby agree as follows:

ARTICLE I.
GENERAL MATTERS

1.1 DEFINED TERMS

As used in this Agreement, including the appendices, exhibits and other attachments hereto, each of the following terms shall have the meaning assigned to such term as set forth below:

1.1.1 "Affiliate" means, in relation to any Person, any other Person:

(a) Which directly or indirectly controls, or is controlled by, or is under common control with, such Person; or

(b) Which directly or indirectly beneficially owns or holds fifty percent (50%) or more of any class of voting stock or other equity interests of such Person; or

(c) Which has fifty percent (50%) or more of any class of voting stock or other equity interests that is directly or indirectly beneficially owned or held by such Person, or

(d) Who either holds a general partnership interest in such Person or such Person holds a general partnership interest in the other Person.

For purposes of this definition, the word "controls" means possession, directly or indirectly of the power to direct or cause the direction of the management or policies of a Person, whether through the ownership of voting securities or otherwise.

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1.1.2 "After-Tax Basis" means, with respect to any indemnity payment to be received by any Person, the amount of such payment (the base payment) supplemented by a further payment (the additional payment) to that Person so that the sum of the base payment plus the additional payment shall, after deduction of the amount of all Federal, state, and local income Taxes required to be paid by such Person in respect of the receipt or accrual of the base payment and the additional payment (taking into account any reduction in such income Taxes resulting from Tax benefits realized by the recipient as a result of the payment or the event giving rise to the payment), be equal to the amount required to be received. Such calculations shall be made on the basis of the highest generally applicable Federal, state, and local income tax rates applicable to the corporation for whom the calculation is being made for all relevant periods, and shall take into account the deductibility of state and local income taxes for Federal income tax purposes. The foregoing calculations shall be made by the recipient Person's third party tax advisors.

1.1.3 "Agreement" has the meaning set forth in the first paragraph hereof, as same may be amended, supplemented or modified from time to time in accordance with the terms hereof.

1.1.4 "Applicable Laws" means any act, statute, law, regulation, permit, license, ordinance, rule, judgment, order, decree, directive, guideline or policy (to the extent mandatory) or any similar form of decision or determination by, or any interpretation or administration of, any of the foregoing by any Government Authority with jurisdiction over the Plant, the Job Site, the performance of the Work or other services to be performed under the Contract Documents.

1.1.5 "Applicable Permits" means any and all permits, clearances, licenses, authorizations, consents, filings, exemptions, rulings or approvals from or required by any Government Authority that are necessary for the performance of the Work or ownership or use of the Work.

1.1.6 "Applicable Standards" means those sound and prudent practices, acts, methods, specifications, codes and standards of design, engineering, assembly, erection, installation, construction, performance, safety and workmanship prudently and generally engaged in or observed by the majority of the professional engineering and construction contractors performing engineering and construction services for major, grid-connected solar electric generating facilities in the United States that, in the exercise of good judgment, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, Applicable Permits, reliability, safety, environmental protection, local conditions, economy and efficiency. Notwithstanding the foregoing, the Work or any portion thereof shall meet specifications that are at least as stringent as those set forth in Appendix A, Scope of Work, and any other specifications set forth in this Agreement.

1.1.7 "Builder's Risk Policy" has the meaning set forth in Section 9.9.4, All Risk Installation and Builder's Risk Insurance, of Article IX, INSURANCE.

1.1.8 "Business Day" means any day other than a Saturday, Sunday or a legal holiday in Florida, United States.

1.1.9 "Capability Verification Test" means the test further described in Appendix HH, Performance Testing.

1.1.10 "Change In Law" means the (A) enactment, adoption, promulgation, modification, or repeal (in each case, after the date of this Agreement but before the date of Provisional Acceptance) of any Applicable Law of any Government Authority of (i) the State of Florida (or any city, county or municipality therein) or (ii) the Federal Government of the United States to the extent such federal law, directly affects the Work performed at the Property Site or (B) the modification after the date of this Agreement of any FPL Permit, and as to both (A) and (B) that establishes requirements that materially and adversely affect Contractor's costs or schedule for performing the Work; provided, however, a change in (x) any federal, state or local Tax law or any other law imposing a Tax, duty, levy, impost, fee, royalty, or charge for which Contractor is responsible hereunder, or (y) any Applicable Law affecting the cost of Contractor's or any Subcontractor's or Vendor's Labor, including increases in worker's compensation rates, shall not be a Change In Law pursuant to this Agreement.

1.1.11 "Change Order" has the meaning set forth in Section 6.1, CHANGE ORDER AT FPL'S REQUEST, of Article VI, CHANGE ORDERS.

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1.1.12 "Changes" has the meaning set forth in Section 6.1, CHANGE ORDER AT FPL'S REQUEST, of Article VI, CHANGE ORDERS.

1.1.13 "Commencement Date" means the date Contractor anticipates it will construct improvements at, or deliver materials to, the Job Site that may be insured pursuant to a builder's risk policy, as set forth in a written Notice delivered by Contractor to FPL pursuant to Section 5.1.1.

1.1.14 "Confidential Information" has the meaning set forth in Section 18.3, CONFIDENTIALITY, of Article XVIII, MISCELLANEOUS.

1.1.15 "Construction and Milestone Payment Schedule" means the schedule of construction/milestone completion installment payments of the Contract Price attached hereto as Appendix D.

1.1.16 "Contract Documents" means this Agreement and all appendices, exhibits incorporated into the Agreement (as set forth in Section 1.3, APPENDICES), as same may be amended, supplemented or modified from time to time in accordance with the terms hereof.

1.1.17 "Contract Price" means the total sum payable by FPL as stated in Section 7.1, Contract Price, for all labor, all materials, and all equipment, which sum shall be due in accordance with the terms of the Contract Documents as consideration for the timely performance of the Scope of Work to be performed by or through Contractor on a "turn-key" basis in order to complete the Project, all in strict accordance with the terms of the Contract Documents, which sum shall only be subject to adjustment in accordance with the Contract Documents, including but not limited to the adjustments contemplated in Appendix J, Option Pricing.

1.1.18 "Contractor" means SunPower Corporation, Systems, a Delaware corporation (as referenced in the opening paragraph hereof), and includes its legal successors and permitted assignees as may be accepted by FPL, in writing, pursuant to the terms of the Contract Documents.

1.1.19 "Contractor Deliverables" means each of the design criteria, system descriptions, manuals, Drawings, Final Plans, design calculations, quality assurance reports and all other material documents relating to the Project to be delivered to FPL in accordance with the requirements of the Contract Documents.

1.1.20 "Contractor Equipment" means all of the equipment, materials, apparatus, structures, tools, supplies and other goods provided and used by Contractor and its Subcontractors and Vendors for performance of the Work but which is not intended to be incorporated into the Plant.

1.1.21 "Contractor Event of Default" has the meaning set forth in Section 15.1, CONTRACTOR EVENTS OF DEFAULT, of Article XV, TERMINATION.

1.1.22 "Contractor Insurance Policies" has the meaning set forth in Section 9.1, CONTRACTOR INSURANCE POLICIES, of Article IX, INSURANCE.

1.1.23 "Contractor Parent Company" has the meaning set forth in Section 11.8, PARENT GUARANTY, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.24 "Contractor Parent Guaranty" has the meaning set forth in Section 11.8, PARENT GUARANTY, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.25 "Contractor Permits" means the Applicable Permits, other than FPL Permits, to be obtained by Contractor as described in Appendix A, Scope of Work, or otherwise required pursuant to the Contract Documents.

1.1.26 "Contractor Project Engineering Manager" means the person designated by Contractor as having the responsibility, authority and supervisory power of Contractor for the engineering and design of the Plant.

1.1.27 "Contractor Project Manager" means the person designated by Contractor as having the centralized responsibility, authority and supervisory power of Contractor for design, procurement, construction, testing and start-up of the Plant, as well as all matters relating to the administration of the provisions of the Contract Documents.

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1.1.28 "Contractor Site Manager" means an employee of Contractor, working under the supervision of the Contractor Project Manager, located at the Property Site on a daily basis.

1.1.29 "Contractor Taxes" has the meaning set forth in Section 3.24, CONTRACTOR TAXES, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.30 "Contractor's Representative" has the meaning given in Section 3.12, PROJECT MANAGEMENT AND CONTRACTOR'S REPRESENTATIVE, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.31 "Credit Trigger Event" shall be deemed to occur if, at the end of the most recently ended fiscal quarter of Contractor, Contractor fails to maintain a Tangible Net Worth of greater than $550,000,000.

1.1.32 "Credit Event of Default" shall be deemed to occur if, at the end of the most recently ended fiscal quarter of Contractor, Contractor fails to maintain a Tangible Net Worth of greater than $100,000,000.

1.1.33 "Credit Rating" means, on the date such rating is determined, the LC Issuing Bank's latest: (i) unsecured debt rating; (ii) corporate credit rating; or (iii) issuer rating.

1.1.34 "Critical Milestones" means the Milestones set forth in Appendix C, Critical Milestones and Milestones.

1.1.35 "Critical Parameters" has the meaning set forth in Section 3.19.7, Quality Assurance Program, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.36 "Critical Path" means a determination of the Project Schedule specifically illustrating those unique activities and durations that must be completed in sequence to complete the Work, which sequence shall be determined using critical path method precedence networking techniques applied by Contractor.

1.1.37 "Damages" has the meaning set forth in Section 16.1, CONTRACTOR INDEMNIFICATION, of Article XVI, INDEMNIFICATION.

1.1.38 "Day" or "day" means a period of twenty-four (24) consecutive hours from 12:00 midnight (Eastern time), and shall include Saturdays, Sundays and all holidays except that in the event a time period set forth in the Contract Documents expires on a Day that is not a Business Day, such period shall be deemed to expire on the next Business Day thereafter.

1.1.39 "Defect" means, any designs, engineering, software, drawings, components, tools, Equipment, installation, construction, workmanship or Work that, in FPL's reasonable judgment:

(a) Do not conform to the terms or requirements of the Contract Documents;

(b) Are not of uniform good quality, free from defects or deficiencies in design, application, manufacture or workmanship, or that contain improper or inferior workmanship; or

(c) Would adversely affect the:

(i) Performance of the Plant under anticipated operating conditions;

(ii) Continuous safe operation of the Plant during the Plant's design life;

(iii) Structural integrity of the Plant;

(iv) Economic value of FPL's investment in the Plant, all as determined by reference to Prudent Utility Practices.

Anything to the contrary notwithstanding, the Parties agree that Work shall be considered to be defective if it does not conform to Applicable Standards.

1.1.40 "Dispute" has the meaning set forth in Section 17.1, FRIENDLY CONSULTATION, of Article XVII, DISPUTE RESOLUTION.

1.1.41 "Drawings" means all:

(a) Specifications, calculations, designs, plans, drawings, engineering and analyses, and other documents which determine, establish, define or otherwise describe the scope, quantity, and relationship of the components of the Plant, including the structure and foundation thereof; and

(b) Technical drawings, operating drawings, specifications, shop drawings, diagrams, illustrations, schedules and performance charts, calculations, samples, patterns, models, operation and maintenance manuals, piping and instrumentation diagrams, underground structure drawings, conduit and grounding drawings, lighting drawings, conduit and cable drawings, electric one-line's, electric schematics, connection diagrams and technical information of a like nature,

prepared or modified by Contractor or any of its Subcontractors or Vendors all of which are required to be delivered by Contractor, or any Subcontractor or Vendor, from time to time under the Contract Documents or at FPL's request which illustrates any of the Equipment or any other portion of the Work, either in components or as completed.

1.1.42 "Energy Yield Test" has the meaning set forth in Section 11.4.

1.1.43 "Environmental Control Program" means the environmental control program provided by FPL to Contractor.

1.1.44 "Environmental Plan" has the meaning set forth in Section 3.19.4, Health Plan, Safety Plan, and Environmental Plan, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.45 "Environmental Resource Plan" means the environmental resource plan prepared by FPL, which has been provided to Contractor prior to the date of the Agreement.

1.1.46 "Equipment" means all of the equipment, materials, apparatus, structures, tools, supplies, goods and other items provided by Contractor and its Subcontractors and Vendors that are installed or incorporated into the Plant or otherwise form or are intended to form part of the Work or the Plant (other than Contractor Equipment).

1.1.47 "Exempt Equipment" has the meaning set forth in Section 3.24.2, Exempt Equipment, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.48 "Expected Energy Output" has the meaning set forth in Section 2.1.2 of Appendix HH.

1.1.49 "Final Acceptance" means that all of the following have occurred as of the most recent applicable Tests:

(a) Provisional Acceptance has been achieved;

(b) The Tests, mechanical calibrations, electrical continuity and ground fault tests have been successfully completed and any Defects found have been corrected;

(c) Either the:

(i) Final Acceptance Performance Level specified in Section 11.3, FINAL ACCEPTANCE PERFORMANCE LEVEL; GUARANTEED PERFORMANCE LEVEL, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, has been met or exceeded as determined pursuant to Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES; or

(ii) Plant has achieved at a minimum the Minimum Performance Level as determined pursuant to Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, and (A) the Contract Price has been reduced in accordance with Section 10.5 for the percentage of the Final Acceptance Performance Level that has not been achieved and (B) Contractor has performed all Remediation Work requested by FPL related to any Work not associated with the percentage of the Final Acceptance Performance Level that has been achieved;

(d) The Plant has been constructed in accordance with the Contract Documents and the Drawings;

(e) The Final Plans accurately reflect the Plant as constructed;

(f) The Plant is capable of being operated in a safe, normal, reliable and continuous manner in accordance with Applicable Laws and Applicable Permits (excluding for this purpose all variances or waivers of any Applicable Permits) and the Contract Documents at all operating conditions and modes specified in the Scope of Work;

(g) Contractor shall have delivered to FPL all operation and maintenance manuals and Final Plans in accordance with the Scope of Work;

(h) No defective or incomplete portions of the Work exist;

(i) Either:

(i) All items on the Punch List have been completed; or

(ii) The Parties have reached an agreement pursuant to Section 10.6, PUNCH LIST, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE, and Contractor has paid all amounts due to FPL pursuant thereto;

(j) All of Contractor's cleanup and related obligations have been completed;

(k) Any and all Liens in respect to the Plant, the Contract Documents, the Equipment, the Job Site or any fixtures, personal property or Equipment included in the Work created by, through or under, or as a result of any act or omission of, Contractor or any Subcontractor, Vendor or other Person providing labor or materials in connection with the Work shall have been released or bonded in form reasonably satisfactory to FPL;

(l) Contractor has delivered to FPL a Contractor's Lien Waiver and Release, in substantially the form of Appendix R, Form of Contractor Certificate for Final Waiver of Liens, from Contractor and Subcontractor's Certificate for Final Waiver of Liens in the form of Appendix R-1, Form of Subcontractor Certificate for Final Waiver of Liens, from each Substantial Subcontractor and Substantial Vendor;

(m) Contractor shall have paid all Schedule Liquidated Damages due under the Contract Documents, if any;

(n) All other outstanding obligations of Contractor hereunder that FPL has notified Contractor of shall have been satisfied; and

(o) FPL has approved of and signed the Final Acceptance Certificate pursuant to Section 10.8.

1.1.50 "Final Acceptance Certificate" means the certificate issued by FPL indicating that Final Acceptance has been achieved by Contractor.

1.1.51 "Final Acceptance Date" means the date of achievement of Final Acceptance as indicated in the Final Acceptance Certificate pursuant to Section 10.8, FINAL ACCEPTANCE OF THE PLANT, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE.

1.1.52 "Final Acceptance Performance Level" means that, at a minimum, the Actual Energy Output is equal to or greater than ninety-five percent (95%) of the Net Energy Output Guarantee when corrected to Guarantee Design Conditions, calculated as follows:

$$\text{Actual Energy Output} \geq (0.95) * \text{Net Energy Output Guarantee}$$

Where "Actual Energy Output" has the meaning given in Section 2.1.2 of Appendix HH.

1.1.53 "Final Acceptance Performance Level Date" has the meaning set forth in Section 11.4.1.

1.1.54 "Final Plans" means final Drawings and final specifications, as revised to reflect the changes during construction, and shall include as-built drawings, piping and instrumentation diagrams, underground structure drawings (including buried piping, all utilities, and critical hidden items), electric one-lines, electric schematics and connection diagrams.

1.1.55 "Financial Closing" means that all of the following events shall have occurred (which events may occur over a period of time) with respect to the Plant: (i) the Financing Documents have been fully executed (which documents may be executed over a period of time) which together provide for financing for the Plant in an amount and on the terms acceptable to FPL; (ii) all conditions precedent to the initial availability of funds under the Financing Documents referred to in the preceding clause (i) have been fulfilled or waived and the first draw thereunder has been made by FPL; and (iii) FPL has received commitments for such equity as is required by FPL and satisfies the requirements of the Financing Parties.

1.1.56 "Financing Documents" means all the loan agreements, notes, indentures, securities, debt instruments, bonds, security agreements, swap agreements, letters of credit and other documents or agreements with a Financing Party or relating to a financing (including refinancing) by a Financing Party.

1.1.57 "Financing Parties" means the lenders, security holders, investors, export credit agencies, multilateral institutions, equity providers and others providing debt or equity financing or refinancing to or on behalf of FPL or any Affiliate of FPL or for the Project or any portion thereof, or any trustee or agent acting on behalf of any of the foregoing.

1.1.58 "Force Majeure Event" has the meaning set forth in Section 14.1, DEFINITION OF FORCE MAJEURE EVENT, of Article XIV, FORCE MAJEURE AND FPL CAUSED DELAY.

1.1.59 "FPL" means Florida Power & Light Company, a Florida corporation (as referenced in the opening paragraph hereof) and it includes its legal successors and those assignees as may be designated by FPL, in writing, pursuant to the terms of this Agreement.

1.1.60 "FPL Caused Delay" means a material delay in Contractor's performance of any Critical Milestone, to the extent Contractor demonstrates that such delay was actually and demonstrably caused by FPL's failure to perform any covenant of FPL hereunder (other than by exercise of rights under this Agreement, including the exercise by FPL of the right to have defective or nonconforming Work corrected or re-executed), including, without limitation, FPL's failure to timely obtain any FPL Permit, and which actually, demonstrably and adversely affects the Critical Path. Contractor expressly acknowledges and agrees that any delay, to the extent caused by Contractor's action or inaction (other than by exercise of rights under this Agreement), is not an FPL Caused Delay.

1.1.61 "FPL Event of Default" has the meaning set forth in Section 15.6, FPL EVENTS OF DEFAULT, of Article XV, TERMINATION

1.1.62 "FPL Interconnection Facilities" shall have the meaning ascribed thereto in Section 2.3 of Appendix A, Scope of Work.

1.1.63 "FPL Permits" means the Applicable Permits to be obtained by FPL as set forth in Appendix A, Scope of Work.

1.1.64 "FPL Taxes" has the meaning set forth in Section 4.9, FPL TAXES, of Article IV, CERTAIN OBLIGATIONS OF FPL.

1.1.65 "GAAP" shall mean generally accepted accounting principles in the United States of America, consistently applied throughout the specified period.

1.1.66 "Government Authority" means any and all foreign, national, federal, state, county, city, municipal, local or regional (or equivalent) authorities, departments, bodies, commissions, corporations, branches, directorates, agencies, ministries, courts, tribunals, judicial authorities, legislative bodies, administrative bodies,

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regulatory bodies, autonomous or quasi-autonomous entities or taxing authorities or any department, municipality or other political subdivision thereof.

1.1.67 "Grid" means the interconnected high voltage transmission facilities being a part of the FPL transmission system.

1.1.68 "Guarantee Design Conditions" means Standard Test Conditions as such term is defined in the Scope of Work and Appendix HH.

1.1.69 "Guaranteed Performance Level" means the Net Energy Output Guarantee, as guaranteed by Contractor pursuant to Section 11.3, FINAL ACCEPTANCE PERFORMANCE LEVEL; GUARANTEED PERFORMANCE LEVEL, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.70 "Guaranteed Performance Test" means the test performed by Contractor in order to determine the Net Energy Output of the Plant, as more particularly described in Section 2.0 of Appendix HH, Acceptance Testing.

1.1.71 "Guaranteed Provisional Acceptance Date" means December 31, 2009, the date which Contractor guarantees that the Project shall achieve Provisional Acceptance, as such date may be extended in accordance with the terms hereof.

1.1.72 "Hazardous Material" means any hazardous or toxic chemicals, hazardous materials, hazardous waste, hazardous constituents, hazardous or toxic or radioactive substances or petroleum products (including crude oil or any fraction thereof) defined or regulated as such under any Applicable Laws.

1.1.73 "Health Plan" has the meaning set forth in Section 3.19.4, Health Plan, Safety Plan, and Environmental Plan, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.74 "Indemnified Person" has the meaning set forth in Section 16.3, CONDITIONS OF INDEMNIFICATION, of Article XVI, INDEMNIFICATION.

1.1.75 "Indemnifying Party" has the meaning set forth in Section 16.3, CONDITIONS OF INDEMNIFICATION, of Article XVI, INDEMNIFICATION.

1.1.76 "Independent Engineer" means the Person appointed by the Financing Parties and approved by FPL to ensure that the Work is completed in accordance with the Contract Documents.

1.1.77 "Initial LC Amount Expiration Date" has the meaning set forth in Section 7.5.1.

1.1.78 "Initial Site Mobilization" means the first instance when any of Contractor or its Subcontractors' or Vendors' Labor or other representatives is present on the Property Site after the date of this Agreement.

1.1.79 "Intangible Asset" means any asset that is treated as an intangible asset according to GAAP, including:

(a) goodwill, including any amounts (however designated on the balance sheet) representing the cost of acquisitions of subsidiaries in excess of underlying tangible assets;

(b) patents, trademarks and copyrights;

(c) leasehold improvements not recoverable at the expiration of a lease; and

(d) deferred charges (including, but not limited to, unamortized debt discount and expense, organization expenses and experimental and development expenses, but excluding prepaid expenses).

1.1.80 "Intellectual Property Rights" has the meaning set forth in Section 3.32, INTELLECTUAL PROPERTY RIGHTS, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.81 "Job Site" means the Property Site (other than the area designated as Protected Areas, if any, and not constituting a part of the Job Site on the survey provided by FPL pursuant to Section 4.7, DESCRIPTION OF PROPERTY SITE, of Article IV, CERTAIN OBLIGATIONS OF FPL) and any other areas where Contractor

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may temporarily obtain care, custody and control, use, easement or license for purposes directly, indirectly or incidentally related to performance of, or as an accommodation to, the Work.

1.1.82 "Labor" means the workforce of the relevant Person, including its staff and employee and non-employee and skilled and unskilled workers.

1.1.83 "Latest Limited Notice to Proceed Date" has the meaning set forth in Section 5.2.2.

1.1.84 "Latest Notice to Proceed Date" has the meaning set forth in Section 5.2.4.

1.1.85 "LC Issuing Bank" means the domestic financial institution, acceptable to FPL and the Financing Parties and satisfying the requirements set forth in Section 7.5.3, LC Issuing Bank, of Article VII, CONTRACT PRICE; PAYMENTS TO CONTRACTOR, which institution will issue the Letter of Credit on behalf of Contractor in connection with the Project, as more particularly described in Section 7.5, LETTERS OF CREDIT, of Article VII, CONTRACT PRICE; PAYMENTS TO CONTRACTOR.

1.1.86 "Letter of Credit" has the meaning set forth in Section 7.5, LETTERS OF CREDIT, of Article VII, CONTRACT PRICE; PAYMENTS TO CONTRACTOR.

1.1.87 "Lien" means any lien, security interest, mortgage, hypothecation, encumbrance or other restriction on title or property interest.

1.1.88 "Lift Stay Order" has the meaning set forth in Section 18.20, ACCEPTANCE OR REJECTION IN BANKRUPTCY, of Article XVIII, MISCELLANEOUS.

1.1.89 "Limited Notice to Proceed" means each notice given by FPL to Contractor directing Contractor to commence a limited portion of the Work.

1.1.90 "Major Equipment" means any item or component, or set of items of components, of the Project with a value in excess of $250,000, the proper or efficient function of which materially affects the Plant's output or reliability.

1.1.91 "Major Manufacturers" means the manufacturers of the Major Equipment.

1.1.92 "Mechanical Completion" means that:

(a) The Equipment for the Project has been installed, including with the required connections and controls to produce electrical power;

(b) All Equipment related to the solar tracking system, if any, has been installed and checked for alignment, lubrication and rotation;

(c) All remaining electrical systems have been checked out and are ready for operation;

(d) All electrical continuity and ground fault tests and all mechanical tests and calibrations have been completed; and

(e) All instrumentation is operational and has been calibrated in accordance with manufacturers' standards and guidelines and, where possible, loop checked.

1.1.93 "Milestones" means the activities, events and targets, or combination thereof, set forth in Appendix C, Critical Milestones and Milestones, attached hereto.

1.1.94 "Minimum Performance Level" means that, at a minimum and as determined in Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, the Net Energy Output is equal to or greater than fifty percent (50%) of the Net Energy Output Guarantee when corrected to Guarantee Design Conditions.

1.1.95 "Module Warranty Period" has the meaning set forth in Section 12.1.4(c).

1.1.96 "Moody's" means Moody's Investor Services, Inc.

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1.1.97 "Net Energy Output" means electrical energy of the Plant, in kWh, measured at the revenue quality meters at the FPL Interconnection Facilities.

1.1.98 "Net Energy Output Guarantee" has the meaning set forth in Section 11.3, GUARANTEED PERFORMANCE LEVEL, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.99 "Noise Guarantee" means that the Project will function at a noise level that is equal to or less than the lower of the noise limitations set forth in Appendix A, Scope of Work, or the noise limitations contained in the Applicable Permits and Applicable Laws (as demonstrated by the Noise Test and excluding for purposes of determining compliance with the Applicable Permits and Applicable Laws all variances and waivers that may be applicable thereto).

1.1.100 "Noise Test" means the tests more particularly described in Appendix A, Scope of Work, which shall be performed simultaneously with the testing of the Minimum Performance Level and the Guaranteed Performance Level in order to evidence satisfaction of the Noise Guarantee for the Plant.

1.1.101 "Notice to Proceed" means the written notice given from FPL to Contractor directing Contractor to commence performance of the entire Work.

1.1.102 "Notice to Proceed Date" has the meaning set forth in Section 5.2.4.

1.1.103 "O&M Contractor" means the Person selected by FPL for the operation and maintenance of the Plant.

1.1.104 "O&M Personnel" has the meaning set forth in Section 3.22, TRAINING OF O&M PERSONNEL, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR

1.1.105 "Operating Guidelines" means the guidelines or requirements specified in the Utility interconnection agreement applicable to the Project.

1.1.106 "Operating Mode Test" means the test further described in Appendix A, Scope of Work.

1.1.107 "Parties" means collectively, FPL and Contractor.

1.1.108 "Party" means individually, FPL or Contractor.

1.1.109 "Payment Output Percentage" means the percentage determined in accordance with the following formula:

Payment Output Percentage = (1.2 x Output Percentage) - 20

Where:

Output Percentage = the percentage of the Guaranteed Performance Level achieved up to 95% (for purposes of Section 10.5.1) and 97% (for purposes of Section 11.4.3).

1.1.110 "Person" means an individual, partnership, corporation, limited liability company, company, business trust, joint stock company, trust, unincorporated association, joint venture, Government Authority or other entity of whatever nature.

1.1.111 "Plant" means the nominal 25 MW (net) solar photovoltaic, electrical generating facility, to be located on the Property Site, including the solar photovoltaic panels, the solar tracking system, if any, and all structures, facilities, appliances, lines, conductors, instruments, apparatus, components, roads and other equipment comprising and integrating the entire facility as more particularly described in Appendix A, SCOPE OF WORK.

1.1.112 "Plant Warranty Period" has the meaning set forth in Section 12.1.4(b).

1.1.113 "Pre-Existing Hazardous Material" means Hazardous Material that existed on or in the Property Site prior to Initial Site Mobilization by Contractor.

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1.1.114 "Procedures Manual" has the meaning set forth in Section 3.19.3, Procedures Manual, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.115 "Project" means the Plant and all equipment, services and utilities related thereto which must be designed, constructed, assembled, erected, commissioned, started, tested and otherwise completed by, or through, Contractor as part of the Scope of Work and in strict accordance with the provisions of the Contract Documents.

1.1.116 "Project Loss Manual" means the project loss manual prepared by FPL which has been provided to Contractor prior to the date of this Agreement.

1.1.117 "Project Schedule" means the schedule for completion of the Work attached hereto as Appendix B, Project Schedule.

1.1.118 "Property Site" means that certain piece of property located in DeSoto County, Florida, as more particularly described in Appendix P, Legal Description of Property Site.

1.1.119 "Protected Areas" has the meaning set forth in Section 3.16.4, *Protected Areas*, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.120 "Provisional Acceptance" means that all of the following have occurred for the Project:

(a) Mechanical Completion has been achieved;

(b) The Plant has been synchronized with the Grid in accordance with the Scope of Work and the Utility's interconnection requirements;

(c) The Plant is capable of being operated safely, normally, reliably and continuously in accordance with the requirements of all Applicable Laws, Applicable Permits and the Contract Documents at all operating conditions and modes specified in the Scope of Work;

(d) The Project has achieved at a minimum the Minimum Performance Level as determined pursuant to Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES;

(e) The Project has achieved the Noise Guarantee simultaneously with the Minimum Performance Level;

(f) The Operating Mode Tests and the Capability Verification Tests have been successfully completed and all criteria for passing such tests have achieved;

(g) Contractor has provided FPL with copies of all Contractor Permits;

(h) The training of O&M Personnel has been completed;

(i) All spare parts required under the Contract Documents have been delivered by Contractor to the Property Site in accordance with Section 3.26, SPARE PARTS AVAILABILITY, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR;

(j) All Work has been completed in accordance with the requirements of the Contract Documents (other than items on the Punch List); and

(k) Contractor shall have paid all Schedule Liquidated Damages due under the Contract Documents, if any.

For the avoidance of doubt, it is expressly acknowledged and agreed that the commencement or completion of any stormwater system to be built in connection with the Project shall not be a condition to achieving Provisional Acceptance.

1.1.121 "Provisional Acceptance Date" means the actual date of achieving Provisional Acceptance as determined pursuant to Section 10.7, PROVISIONAL ACCEPTANCE, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE.

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1.1.122 "Prudent Utility Practices" means those sound and prudent practices, acts, methods, specifications, codes and standards generally followed by the United States electric utility industry with respect to design, construction, operation, and maintenance of first class, major electric generating, transmission, and distribution facilities (including but not limited to, the engineering, operating and safety practices generally followed by the electric utility industry) that, in the exercise of good judgment, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, Applicable Permits, reliability, safety, environmental protection, local conditions, economy and efficiency.

1.1.123 "Punch List" has the meaning set forth in Section 10.6, PUNCH LIST, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE.

1.1.124 "Qualified Insurer" has the meaning set forth in Section 9.3, QUALIFIED INSURERS, of Article IX, INSURANCE.

1.1.125 "Quality Assurance Program" has the meaning set forth in Section 3.19.7, Quality Assurance Program, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.126 "Quality Control Manual" has the meaning set forth in Section 3.19.7, Quality Assurance Program, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.127 "Remediation Work" means work required by FPL to remove all Work and Contractor Equipment from the Property Site and restore the Property Site to the condition of the Property Site immediately prior to Initial Site Mobilization.

1.1.128 "Remedial Plan" means a plan of corrective action, submitted by Contractor pursuant to Section 10.5, PERFORMANCE SHORTFALLS, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE, that specifies in reasonable detail the actions Contractor proposes to undertake to cause the Project to satisfy the Final Acceptance Performance Level, and the period of time in which Contractor proposes to complete the corrective action; provided that such corrective action is reasonably likely to cause the Project to satisfy the Final Acceptance Performance Level as determined by root cause analysis of the deficiencies identified by previous testing.

1.1.129 "Request for Payment" means the written requests from Contractor to FPL for payment hereunder, which requests shall be in substantially the form of Appendix F, Form of Request for Payment.

1.1.130 "S&P" means Standard and Poor's Ratings Group (a division of McGraw Hill Companies).

1.1.131 "Safe and Secure Workplace Policy" means the safe and secure workplace policy of FPL which is attached hereto as Appendix Z-1, Safe and Secure Workplace Policy, as same may be amended or modified by FPL from time to time.

1.1.132 "Safety Plan" has the meaning set forth in Section 3.19.4, Health Plan, Safety Plan and Environmental Plan, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.133 "Schedule Liquidated Damages" has the meaning set forth in Section 11.2, SCHEDULE LIQUIDATED DAMAGES, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.134 "Scheduled Synchronization Date(s)" means the date identified by Contractor in a notice received by FPL at least one hundred forty (140) days prior to such date as being the date on which Contractor will first attempt to cause the generating equipment of the Project to be electrically synchronized and connected to the Grid.

1.1.135 "Scope of Work" means the services and work to be provided, or caused to be provided, by or through Contractor under the Contract Documents for the Contract Price, as more particularly described in Appendix A, Scope of Work, as the same may be amended from time to time in accordance with the terms hereof, and which Scope of Work includes, without limitation, all licenses, Contractor Permits, technical assistance, engineering, assembly, construction management, construction, services, labor, materials,

equipment, Contractor Equipment, operations and management that are indicated on, inferable from, or incidental to, the Contract Documents or the Drawings prepared in connection with the Contract Documents or that are likely to be required in accordance with Applicable Law, or that are properly and customarily included within the general scope and magnitude of the work incorporated into similar projects having similar output and performance requirements, all in order to produce a Project that complies with the requirements of the Contract Documents.

1.1.136 "Subcontractor" means any contractor, constructor or material man who performs any portion of the Scope of Work other than Contractor.

1.1.137 "Substantial Subcontractor" means a Subcontractor whose contract or contracts (in the aggregate) with Contractor require payments by Contractor totaling at least Two Hundred Fifty Thousand Dollars ($250,000.00).

1.1.138 "Substantial Vendor" means a Vendor whose contract or purchase orders (in the aggregate) with Contractor require payments by Contractor of at least Two Hundred Fifty Thousand Dollars ($250,000.00).

1.1.139 "Switchyard Facilities" means the area adjacent to the Plant designated by FPL for the 23 kV voltage equipment and apparatus used for connecting the Plant to the FPL Interconnection Facilities, all as more particularly described in Appendix A, Scope of Work.

1.1.140 "Tangible Net Worth" with respect to any Person means such Person's total stockholder's equity minus its Intangible Assets, each as would be reflected on a balance sheet prepared in accordance with GAAP.

1.1.141 "Tax" or "Taxes" means all fees, taxes, including sales taxes, use taxes, stamp taxes, value-added taxes, ad valorem taxes and property taxes (personal and real, tangible and intangible), customs, duties, tariffs, levies, assessments, withholdings and other charges and impositions of any nature, plus all related interest, penalties, fines and additions to tax, now or hereafter imposed by any Applicable Law or Government Authority (including penalties or other amounts payable pursuant to subtitle B of Title I of ERISA).

1.1.142 "Termination Payment" has the meaning set forth in Section 15.3.2, Termination Payment, of Article XV, TERMINATION.

1.1.143 "Termination Payment Schedule" means Appendix N hereto.

1.1.144 "Test Notice" has the meaning set forth in Section 10.1.2, Test Notice, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE

1.1.145 "Tests" means the Operating Mode Test, the Capability Verification Test, the Guaranteed Performance Test and the Noise Test.

1.1.146 "Utility" means FPL.

1.1.147 "Vendor" means any supplier, manufacturer or vendor of Equipment to Contractor or any Subcontractor.

1.1.148 "Warranty Period" and "Warranty Periods" have the meanings set forth in Section 12.1.4, Warranty Period, of Article XII, CONTRACTOR'S WARRANTIES.

1.1.149 "Work" has the meaning set forth in Section 3.1, SCOPE OF WORK; APPLICABLE STANDARDS, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, and includes the Plant, the Equipment, the Contractor Deliverables and any other product or result of the Work, but excludes any storm water system at or related to the Project Site.

1.2 INTERPRETATION

Unless the context of the Contract Documents otherwise requires:

1.2.1 The headings contained in this Agreement are used solely for convenience and do not constitute a part of this Agreement between the Parties, nor should they be used to aid in any manner to construe or interpret this Agreement;

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1.2.2 The gender of all words used herein shall include the masculine, feminine and neuter and the number of all words shall include the singular and plural words;

1.2.3 The terms "hereof", "herein" "hereto" and similar words refer to this entire Agreement and not to any particular Article, Section, Appendix or any other subdivision of this Agreement;

1.2.4 References to "Article," "Section" or "Exhibit" are to this Agreement unless specified otherwise;

1.2.5 Reference to "this Agreement" (including any Appendix hereto) or any other agreement, Exhibit, permit or document shall be construed as a reference to such agreement or document as the same may be amended, modified, supplemented or restated, and shall include a reference to any document which amends, modifies, supplements or restates, or is entered into, made or given pursuant to or in accordance with its terms;

1.2.6 References to any law, statute, rule, regulation, notification or statutory provision (including Applicable Laws, Applicable Permits and the Operating Guidelines) shall be construed as a reference to the same as it may have been, or may from time to time be, amended, modified or re-enacted;

1.2.7 References to any Person shall be construed as a reference to such Person's successors and permitted assigns; and

1.2.8 References to "includes," "including" and similar phrases means "including, without limitation."

1.3 APPENDICES

The following Appendices are attached to and incorporated into and made a part of this Agreement:

1.3.1 Appendix A ..... Scope of Work

1.3.2 Appendix B..... Project Controls Requirements

1.3.3 Appendix C..... Critical Milestones and Milestones

1.3.4 Appendix D ..... Construction and Milestone Payment Schedule

1.3.5 Appendix E..... Credit Trigger Event

1.3.6 Appendix F..... Form of Request for Payment

1.3.7 Appendix G ..... Form of Final Acceptance Certificate

1.3.8 Appendix H ..... Form of Contractor Certificate for Partial Waiver of Liens

1.3.9 Appendix H-1 ..... Form of Subcontractor Certificate for Partial Waiver of Liens

1.3.10 Appendix I..... Form of Contractor Parent Guaranty

1.3.11 Appendix J..... Option Pricing

1.3.12 Appendix K ..... Module Warranty

1.3.13 Appendix L..... Operating and Maintenance Manuals

1.3.14 Appendix M..... FPL Permits

1.3.15 Appendix N ..... Termination Payment Schedule

1.3.16 Appendix O ..... Project Management Team

1.3.17 Appendix P..... Legal Description of Property Site

1.3.18 Appendix Q ..... Intentionally Deleted

1.3.19 Appendix R..... Form of Contractor Certificate for Final Waiver of Liens

1.3.20 Appendix R-I..... Form of Subcontractor Certificate for Final Waiver of Liens

1.3.21 Appendix S ..... Form of Request for Change Order

1.3.22 Appendix T ..... Intentionally Deleted

1.3.23 Appendix U ..... Form of Letter of Credit

1.3.24 Appendix V ..... Contractor's Exclusions

1.3.25 Appendix W ..... Intentionally Deleted

1.3.26 Appendix X ..... Intentionally Deleted

1.3.27 Appendix Y ..... Form of Quality Assurance Programs

1.3.28 Appendix Z ..... Form of Safety Plan

1.3.29 Appendix Z-1 ..... Safe and Secure Workplace Policy

1.3.30 Appendix HH ..... Acceptance Testing

1.3.31 Appendix II ..... Performance Degradation Testing

1.4 ORDER OF PRECEDENCE

1.4.1 In the event of conflicts among the terms of the Contract Documents, interpretations shall be based upon the following Contract Documents which are set forth in ranked order of precedence:

(a) Amendments, addenda or other modifications to the Contract Documents (including Change Orders) duly signed and issued after the signing of this Agreement and effected in accordance with the terms hereof, with those of a later date having precedence over those of an earlier date;

(b) The Agreement; and

(c) The Appendices to the Agreement.

In the event of a conflict among, or within, any other Contract Document(s) within any one of the levels set forth in the foregoing order of precedence, or between the Contract Documents and Applicable Laws or Applicable Permits, or among Applicable Laws or Applicable Permits themselves, the more stringent or higher quality requirements shall control. All obligations imposed on Contractor and each Subcontractor under the Agreement or under Applicable Laws, Applicable Permits or Applicable Standards and not expressly imposed or addressed in the Contract Documents shall be in addition to and supplement the obligations imposed on Contractor under the Contract Documents, and shall not be construed to create an "irreconcilable conflict."

1.5 LANGUAGE

1.5.1 The Contract Documents and all documentation to be supplied hereunder (including, without limitation, all Contractor Deliverables and all warranties provided hereunder) shall be in the English language.

ARTICLE II.
RETENTION OF CONTRACTOR

2.1 RETENTION OF CONTRACTOR

FPL hereby engages Contractor, and Contractor hereby agrees to be engaged by FPL to perform the Work in accordance with the terms and conditions set forth herein.

2.2 STATUS OF CONTRACTOR; NO PARTNERSHIP

Contractor shall be an independent contractor with respect to any and all Work performed and to be performed under the Contract Documents. The Contract Documents shall not be interpreted or construed to create an association, joint venture or partnership relationship among or between the Parties or any similar relationship, obligations or liabilities. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, act on behalf of, or to act as or be an agent or representative of, or to otherwise bind or obligate the other Party.

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2.3 SUBCONTRACTORS AND VENDORS.

2.3.1 Subject to the terms hereof, Contractor shall have the right to have any portion of the Work performed by a Subcontractor or Vendor qualified to perform such Work pursuant to written subcontracts or written purchase orders; provided that Contractor shall not be relieved from any liability or obligation under the Contract Documents. Except as otherwise expressly provided in the Contract Documents, Contractor shall be solely responsible for engaging, managing, supervising and paying all such Subcontractors and Vendors. Contractor shall require that all Work performed, and all Equipment provided by Subcontractors and Vendors are received, inspected and otherwise furnished in accordance with the Contract Documents, and Contractor shall be solely liable for all acts, omissions, liabilities and Work (including Defects therein) of such Subcontractors and Vendors. FPL shall not have any obligation or liability to any Subcontractor or Vendor. Nothing in any contract, subcontract or purchase order with any Subcontractor or Vendor shall in any way diminish or relieve Contractor from any duties and obligations under the Contract Documents; and each such contract, subcontract and purchase order must provide that the rights thereunder are assignable to FPL and the Financing Parties or their designees at any time without the prior consent of the applicable Subcontractor or Vendor. No Subcontractor or Vendor is intended to be or shall be deemed a third-party beneficiary of the Contract Documents.

2.3.2 FPL shall have the right to approve, in advance in writing, each Substantial Subcontractor and Substantial Vendor in accordance with the terms hereof. Prior to retaining any Substantial Subcontractors or Substantial Vendors, Contractor shall notify FPL in writing and provide it with such information as necessary to enable FPL to evaluate each such proposed Substantial Subcontractor or Substantial Vendor for the portion of the Work proposed to be performed by it. Within fifteen (15) days after receipt of such information, FPL shall advise Contractor if any proposed Substantial Subcontractor or Substantial Vendor is unacceptable. If FPL fails to object to any proposed Substantial Subcontractor or Substantial Vendor within such fifteen (15) day period, Contractor may retain such Substantial Subcontractor or Substantial Vendor for the portion of the Work proposed. If FPL objects in writing (stating with reasonable detail the basis for such objection) within such fifteen (15) day period to such proposed Substantial Subcontractor or Substantial Vendor, Contractor shall not retain such proposed Substantial Subcontractor or Substantial Vendor. Approval of any Substantial Subcontractor or Substantial Vendor under this paragraph shall only be for the portion of the Work so approved. Contractor hereby acknowledges and agrees that the review and/or acceptance of any subcontract by FPL and the acceptance of the approved Substantial Subcontractors and Substantial Vendors shall not: (i) modify, in any way, the obligations of Contractor pursuant to the Contract Documents; or (ii) be raised as a claim or as a defense or counterclaim to any claim in connection with the Contract Documents.

2.3.3 Contractor shall submit to FPL a copy of each purchase order or agreement entered into with a Substantial Subcontractor or Substantial Vendor for Major Equipment. Each purchase order or agreement shall show, where applicable, the Vendor's or Subcontractor's name, manufacturer's name, materials type, model number, size, quantity and lists of the Major Equipment ordered, and shall be submitted to FPL when issued for purchase. For purposes of clarity, it is understood and agreed that no document required to be submitted to FPL pursuant to this Section 2.3.3 shall be required to contain any economic terms, all of which economic terms may be redacted prior to submission to FPL.

2.3.4 Each subcontract and purchase order shall require such Subcontractor and Vendor to assume toward Contractor those terms and conditions of contracting which Contractor customarily includes in its subcontracts. At a minimum, all subcontracts shall require the Subcontractors to comply with Applicable Laws and Applicable Permits, shall provide that FPL has the right of inspection as provided hereunder and require such Subcontractors and Vendors to:

(a) Be subject to the labor obligations hereunder as well as the safety and security provisions of the Contract Documents;

(b) Provide guarantees and warranties with respect to its portion of the Work and the Equipment,

(c) Provide certificates of insurance as set forth herein;

(d) Be subject to the dispute resolution procedures as required herein; and

(e) Have such terms and conditions as are reasonably and customarily obtained.

All subcontracts shall preserve and protect the rights of FPL, shall not prejudice such rights and shall require each Subcontractor to enter into similar agreements with other Subcontractors.

2.3.5 In addition to the requirements set forth in Section 2.3.4, above, Contractor shall include in each subcontract and purchase order the following language to make FPL an express third-party beneficiary of such subcontract or purchase order:

> "The parties hereto agree and acknowledge that the services/work/equipment to be provided hereunder by [subcontractor] will be incorporated into the power station being developed by [FPL]. As such, the parties expressly agree that FPL is a third party beneficiary of this [Agreement] entitled, in its own name or in the name of [Contractor], to enforce this [Agreement] against [subcontractor]."

ARTICLE III.
CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR

3.1 SCOPE OF WORK; APPLICABLE STANDARDS.

3.1.1 Contractor shall, at its own cost and expense:

(a) Design, engineer, procure, construct, start up, and carry out the Tests for the Plant, and perform its other obligations hereunder, including completion of the Scope of Work and any warranty work hereunder; and

(b) Manage, supervise, inspect and furnish all Labor, Equipment, Contractor Equipment, temporary structures, temporary utilities, products and services for the foregoing,

all on a turnkey basis, in accordance with the Contract Documents, including, without limitation, the Project Schedule and the Scope of Work, as the same may be modified from time to time in accordance with the terms hereof by a Change Order or other amendment hereto (all of the foregoing being collectively referred to in this Agreement as the "Work").

3.1.2 Subject to the remedies provided for herein, Contractor shall perform the Work and turn the Plant over to FPL in a manner that is:

(a) Sufficient, complete and adequate in all respects necessary for the Project to successfully achieve Provisional Acceptance by the Guaranteed Provisional Acceptance Date;

(b) In conformance with professional standards and skill, expertise and diligence of design and construction professionals regularly involved in first class, major grid-connected solar power projects in the United States;

(c) In compliance with the terms of the Contract Documents, the Operating Guidelines, the Utility's interconnection requirements, all Applicable Laws, Applicable Standards and Applicable Permits; and

(d) Approved as to form, use and content by all Government Authorities and private entities authorized to administer or enforce any building or construction code or standard whose approval of the final design of the Plant, or any portion thereof, is necessary for the construction, operation or interconnection of the Plant.

3.1.3 *Contractor's Exclusions*. In light of the foregoing, Contractor has included within the Contract Price the cost to complete the entire Scope of Work. Items need not be specifically listed in the Contract Documents or in Appendix A, Scope of Work, in order to be deemed to be items within the Scope of Work. It is understood that Contractor is better qualified to list exclusions than FPL is to list inclusions. Therefore,

any item indicated on the Contract Documents, inferable therefrom, incidental thereto or required in accordance with any Applicable Law, Applicable Standards, Applicable Permits or Prudent Utility Practices, that is not specifically excluded from the Scope of Work in Contractor's exclusions set forth on Appendix V, Contractor's Exclusions, is to be considered as part of the Scope of Work. In addition, the Scope of Work includes all that should be properly included and all that would be customarily included within the general scope and magnitude of the Work in order to achieve the Guaranteed Performance Level applicable to the Project. As a result, except for Contractor's exclusions set forth on Appendix V, Contractor's Exclusions, Contractor hereby waives any and all claims for an increase in the Contract Price or an extension of the Guaranteed Provisional Acceptance Date based, in whole or in part, upon an assertion that any certain license, technical assistance, engineering, assembly, construction, service, labor, material, equipment, operation or management is beyond the Scope of Work when such license, technical assistance, engineering, assembly, construction, service, labor, material, equipment, operation or management is indicated in the Contract Documents, the Drawings or other instruments of service prepared in connection with the Contract Documents, inferable therefrom, incidental thereto, required in accordance with any Applicable Law, Applicable Standards, Applicable Permits, Prudent Utility Practices or otherwise necessary in order to complete a Project in accordance with and subject to the requirements of the Contract Documents.

3.1.4 Contractor shall perform the Work in conformance with professional standards and skill, expertise and diligence of design and construction professionals regularly involved in first class, major, grid-connected solar power projects for public utilities in the United States. Without limiting the generality of the foregoing, Contractor shall:

(a) Comply with, and shall cause the Work and all components thereof to comply with, the Operating Guidelines, Applicable Laws, Applicable Standards, Applicable Permits, Prudent Utility Practices, the requirements of the Contract Documents and the generally accepted standard of care, skill and diligence as would be provided by, in the case of engineering services, a prudent engineering firm, and in the case of construction or procurement services, by a prudent construction firm, in each case experienced in supplying such services in the United States to power-producing entities for first class, major power projects;

(b) Cause the Work to be performed with Contractor's best skill and judgment, in a safe, expeditious, good and workmanlike manner in accordance with the preceding paragraph (a);

(c) Cause the Work to be approved as to form, use and content by all Government Authorities and private entities authorized to administer or enforce any building or construction code or standard whose approval of the final design of the Project, or any portion thereof, is necessary for the construction or operation of the Project;

(d) Cause the Plant to be designed to operate, and shall cause the Plant to be capable of being operated, at all levels and operating modes in accordance with the Operating Guidelines, Applicable Laws, Applicable Standards, Applicable Permits, Prudent Utility Practices and the requirements of the Contract Documents; and

(e) Cause the Plant and all items of Equipment and improvements comprising the Plant to be designed, manufactured, installed, calibrated and tested where applicable in accordance with the published standards (as of the dates specified) of the organizations listed in the Scope of Work and Contractor shall notify FPL of any standards of such organizations that are inconsistent with each other and advise FPL of the manner in which it intends to resolve such inconsistency in accordance with the published standard.

Contractor shall inspect or cause to be inspected all items to be incorporated into or used in the performance of the Work and shall reject those items determined not to be in compliance with the requirements of the Contract Documents. Except as otherwise expressly provided in this Agreement, the standard of performance set forth in this Section 3.1.4, shall apply to all aspects of the Work, and this Section 3.1.4, shall be deemed to be incorporated by reference into each provision of the Contract Documents describing the Work, Contractor's obligations hereunder, or referring to the "requirements of

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the Contract Documents", "in accordance with the Contract Documents" or words of similar effect. In no event will references in any provision of Contract Documents to one or more of the standards, guidelines, practices, regulations, laws, or permits contained in this Section 3.1.4, be interpreted to limit in the applicability of all such standards, guidelines, practices, regulations, laws, and permits to such provision. Additionally, as a condition to meeting Provisional Acceptance and Final Acceptance, the Work for such milestone must be completed in accordance with all of the standards, guidelines, practices, regulations, laws, and permits contained in this Section 3.1.4.

3.1.5 Contractor acknowledges that this Agreement constitutes, subject to the terms hereof, a fixed price obligation to:

(a) Engineer, design, procure, construct, test and start up through Provisional Acceptance a turnkey Project, complete in every detail, within the time and for the purpose designated herein;

(b) Achieve Final Acceptance within the time designated herein;

(c) Comply with all of the warranty obligations set forth in this Agreement; and

(d) Perform Contractor's other obligations hereunder.

References to the obligations of Contractor under this Agreement as being "turnkey" and performing the Work on a "turnkey basis" means that Contractor is obligated to supply all of the Equipment and design services, install all of the Equipment and supply all labor and to supply and perform all of the Work, in each case as may reasonably be required, necessary, incidental, or appropriate (whether or not specifically set forth in this Agreement) to complete the Work such that the Project satisfies the applicable terms, conditions, and Contractor's obligations concerning the Guaranteed Performance Level and other guarantees and requirements set forth in this Contract Documents, all for the Contract Price.

3.2 CONTROL AND METHOD OF THE WORK.

3.2.1 Subject to the terms hereof, Contractor shall be solely responsible for performing or causing to be performed the Work in accordance with the terms of the Contract Documents, and for all means, methods, techniques, sequences, procedures, and safety and security programs in connection with such performance. Contractor shall inform FPL in advance concerning its plans for carrying out the Work.

3.2.2 Whenever the words "as ordered," "as directed," "as required," "as permitted," "as allowed," "approved," "reasonable," "suitable," "acceptable," "properly," "satisfactory," or words or phrases of similar effect and import are used, it shall be understood that none of such terms shall imply that FPL has any authority over, right to control or responsibility for supervision of Contractor or its Subcontractors or Vendors, such supervision (including sole control over and responsibility therefor) being strictly reserved for Contractor. Any method of Work suggested by FPL that is used by Contractor will be used at the risk and responsibility of Contractor, and FPL will assume no responsibility therefor.

3.3 COMPLIANCE WITH LAW

Contractor shall comply, and shall cause all of its Subcontractors, Vendors and Persons that it has a right to direct who are engaged in the performance of any of the Work to comply with, all Applicable Laws and Applicable Permits. Contractor shall perform the Work in a manner designed to protect the environment on and off the Job Site and minimize damage or nuisance to Persons and property of the public or others, including damage or nuisance resulting from pollution, noise or other causes arising as a consequence of methods of construction or operation of the Plant. The foregoing shall not be construed as to limit Contractor's obligations and liabilities under Section 3.15, PROTECTION AND SAFETY, below.

3.4 CERTAIN MATTERS PERTAINING TO JOB SITE.

3.4.1 *Project Inspection.* Contractor acknowledges that, prior to the date of this Agreement, Contractor:

(a) Has made a complete and careful examination of the Job Site and the surrounding areas, drawings and specifications and other information set forth in the Contract Documents;

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(b) Has made a complete and careful examination to determine the difficulties and hazards incident to the performance of the Work, including:

(i) The location of the Project;

(ii) The proximity of the Project to adjacent facilities and structures;

(iii) The conditions of the roads and waterways in the vicinity of the Job Site, including the conditions affecting shipping and transportation, access, disposal, handling and storage of materials;

(iv) The nature and character of the soil, terrain, surface and subsurface conditions of the Job Site;

(v) The labor conditions in the region of the Job Site;

(vi) Applicable Laws and Applicable Permits;

(vii) Rights of FPL regarding the Job Site as set forth herein;

(viii) The local weather conditions based upon previous weather data;

(ix) The qualifications of all Subcontractors and Vendors;

(x) The Safe and Secure Workplace Policy, the Project Loss Manual and Environmental Control Program; and

(xi) All other known matters and other matters that Contractor should know under Applicable Standards that might affect Contractor's performance under this Agreement or the design, engineering, procurement, construction, start-up, demonstration and testing of the Plant; and

(c) Has determined to Contractor's satisfaction the nature and extent of such difficulties and hazards.

3.4.2 *Responsibility for Interpreting Sub-Surface Data*. Notwithstanding the above, where FPL has made investigations of subsurface conditions in areas where Work is to be performed under this Agreement, such investigations are made by FPL for the purpose of study and design. To the extent the records of such investigation are included in this Agreement, the interpretation of such records shall be the sole responsibility of Contractor. FPL assumes no responsibility whatsoever with respect to the sufficiency or accuracy of such investigations, the records thereof, or of the interpretations set forth and there is no warranty or guarantee, either express or implied, that the conditions indicated by such investigations or records thereof are representative of those existing throughout such areas, or any part thereof, or that unforeseen developments may not occur, or that materials other than or in proportions different from those indicated may not be encountered.

3.4.3 In light of the foregoing and subject to Section 3.4.4, Differing Condition, Contractor accepts the Job Site in its existing condition and waives any right to additional compensation beyond the Contract Price or an extension of the Guaranteed Provisional Acceptance Date, and any other claims that may arise due, in whole or in part, to errors or omissions in, or inconsistencies among, the Contract Documents and any information provided in connection with the Project. Contractor shall be solely responsible for performing any preliminary Work on the Job Site necessary for the commencement of construction to occur, including removal of all physical impediments to performing Work on the Job Site, above and below ground.

3.4.4 *Differing Condition*. Notwithstanding the acknowledgments set forth in Section 3.4.1, no less than sixty (60) days prior to commencement of Contractor's mobilization on the Job Site (the "Geotechnical Investigation Completion Date"), Contractor may conduct a geotechnical investigation in the location of the Job Site or any portion thereof as Contractor reasonably deems necessary to confirm the site conditions referred to in Sections 3.4.1, and 3.4.2, above. If as a result of the geotechnical investigation, Contractor:

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(a) Encounters any concealed subsurface conditions which a reasonable, experienced Contractor would not foresee existing at the Job Site and which vary materially from the conditions shown in the Contract Documents; and

(b) Any such condition causes a material increase or decrease in the Contract Price or time required for performance of the Work or otherwise materially affects any provision of this Agreement,

then Contractor shall notify FPL thereof and FPL may either:

(i) Issue a Change Order to address such condition; or

(ii) Terminate this Agreement pursuant to Section 15.3.

Contractor specifically waives the right to make any such claims after the Geotechnical Investigation Completion Date. Except as set forth in this Section 3.4.4, Contractor assumes the risk of surface and subsurface conditions at the Job Site and shall not be entitled to an extension of the Project Schedule or an increase in the Contract Price.

3.5 FPL ACCESS TO JOB SITE

Subject to Contractor's reasonable safety policies, FPL shall have the right to have representatives on the Job Site full time. In addition, Contractor shall provide reasonable access to the Job Site and the Work at all times to FPL, FPL's other contractors, the Independent Engineer and the Financing Parties and their respective employees, representatives, agents and consultants, subject to Contractor's reasonable safety policies.

3.6 INSPECTION AND TESTING OF WORK IN PROGRESS.

3.6.1 Each item of Equipment to be supplied by Contractor shall be subject to inspection and testing during and upon completion of its fabrication and installation in accordance with the provisions of the Scope of Work. Without limiting the foregoing, Contractor shall be responsible for inspection and testing of the Equipment in accordance with Applicable Standards.

3.6.2 Contractor shall perform inspection, expediting, quality surveillance and traffic services as are required for performance of the Scope of Work. Contractor shall perform such detailed inspection of Work in progress at intervals appropriate to the stage of construction or fabrication of the Project as is necessary to ensure that such Work is proceeding in accordance with this Agreement and the Contract Documents and to protect FPL against Defects and deficiencies in such Work. At least fifteen (15) Business Days prior to the time Contractor or its representative intends to inspect any item of Major Equipment, Contractor shall notify FPL in writing of such inspection which notice shall state the date, time and place where such inspection is to be conducted (provided that, if the inspection will occur at a location outside of the United States of America, Contractor shall provide such notice as soon as possible but in no event less than fifteen (15) Business Days prior to such inspection). FPL and/or its designated agent may, at FPL's option, accompany Contractor to the inspection by notifying Contractor in writing within five (5) Business Days of receipt of notice of the inspection. FPL's failure to notify Contractor within the permitted time period shall be deemed to be a decision by FPL not to attend the inspection. Contractor shall arrange for access to the manufacturer's facilities to permit any such inspection to be conducted smoothly. Contractor shall reimburse FPL for any costs necessarily and reasonably incurred by FPL due to Contractor's failure to prepare any portion of the Work for inspection or testing after having provided notice to FPL of any such inspection or test. With respect to any inspection that FPL chooses not to attend, Contractor shall:

(a) Keep FPL informed in all material respects of the progress and quality of all work;

(b) Advise FPL of any deficiencies revealed through such inspections and of the measures proposed by Contractor to remedy such deficiencies in order to avoid any delay in the completion of the Work and Contractor's performance of the Work; provided that, any such notice provided pursuant to this Section 3.6.2, shall not constitute a request for adjustment, extension or modification of the Project Schedule or FPL's consent to any of the same; and

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(c) Upon FPL's request, provide FPL with a reasonable opportunity to review Contractor's records with respect to such inspections. Contractor shall include the right to inspection by FPL or its representative in all subcontracts and purchase orders.

3.6.3 Contractor shall permit FPL and, as authorized by FPL, any Person designated by FPL, and the Financing Parties to inspect, test and observe the Work from time to time; provided, however, that none of such Persons shall have any authority or responsibility for such Work. Contractor shall provide FPL each month during performance of the Work with a schedule of all testing proposed for the following three (3) month period in compliance with the requirements of the Scope of Work.

3.7 NO WAIVER OF RESPONSIBILITY

No inspection made, acceptance of Work, payment of money or approval given by FPL, the Financing Parties or the Independent Engineer shall relieve Contractor of its obligations for the proper performance of the Work in accordance with the terms hereof. Subject to the limitations of Article XII, Contractor's Warranties, FPL may reject any Work with Defects or which is not in accordance with the requirements of the Contract Documents, regardless of the stage of completion, the time or place of discovery of error, and whether FPL previously accepted any or all of such Work through oversight or otherwise. Except with respect to the achievement of Provisional Acceptance and Final Acceptance, no approval given by FPL, in and of itself, shall be considered as an assumption of risk or liability by any such Person. Any such approval shall mean that the Person giving the approval has no objection to the adoption or use by Contractor of the matter approved at Contractor's own risk and responsibility. Contractor shall have no claim relating to any such matter approved, including any claims relating to the failure or inefficiency of any method approved.

3.8 DEFECTIVE WORK

3.8.1 Prior to Provisional Acceptance, Contractor shall at its own cost and expense correct or replace any Work that contains a Defect, or is not otherwise in accordance with the Contract Documents. Equipment that has been replaced, if situated on the Job Site, shall be removed by Contractor from the Job Site at Contractor's own cost and expense.

3.8.2 If Contractor or any Subcontractor defaults or neglects to carry out the Scope of Work in accordance with the Contract Documents and Contractor fails within a reasonable period of time (as reasonably determined by FPL) after it knows or should have known of such default or neglects to commence and continue correction of such default or neglect with diligence and promptness, FPL may, without prejudice to other remedies FPL may have under this Agreement, correct such deficiencies. In such event, an appropriate Change Order shall be issued deducting from payments then or thereafter due to Contractor the reasonable cost of correcting such deficiencies, including reasonable compensation for the costs to enforce this provision (including reasonable attorneys' fees) and any consultant's additional services and reasonable expenses made necessary by such default, neglect or failure. If payments then or thereafter due to Contractor are not sufficient to cover such amounts, Contractor shall pay the difference to FPL within three (3) days from FPL's request therefor.

3.8.3 Contractor shall correct any and all deficiencies as required by the Contract Documents notwithstanding any actual or possible legal obligation or duty of a Subcontractor concerning same and nothing contained in this Section shall modify Contractor's obligation to achieve Final Acceptance in accordance with the Contract Documents.

3.9 CLEAN-UP.

3.9.1 Without limiting the provisions of Section 3.16, ENVIRONMENTAL MATTERS, Contractor shall at all times keep the Job Site reasonably free from waste, rubbish and Hazardous Material, other than Pre-Existing Hazardous Material, relating to its Work. Contractor shall maintain the Job Site in a neat and orderly condition throughout the performance of the Work. Contractor shall employ sufficient personnel to clean its office and FPL's office at the Job Site and work areas each working day and shall cooperate with the other Persons working at the Job Site to keep the Job Site clean.

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3.9.2 Prior to the Final Acceptance Date or as soon as practicable after the termination of this Agreement by FPL in accordance with the provisions of Article XV, TERMINATION, Contractor shall:

(a) Remove all Contractor Equipment from the Job Site (other than equipment, supplies and materials necessary or useful to the operation or maintenance of the Plant and Equipment and equipment, supplies and materials directed by FPL to remain at the Job Site until completion of the Plant);

(b) Clean out all pits, pipes, chambers and conduits;

(c) Tear down and remove all temporary structures on the Job Site built by it or its Subcontractors and restore such areas to a condition consistent with that of a newly constructed photovoltaic solar power plant, except as required by Applicable Law, Section 3.16.4, Protected Areas, or any other provision of this Agreement; and

(d) Remove all waste, rubbish and Hazardous Material from and around the Job Site, except that Contractor shall not be required to excavate, remove, transport or otherwise dispose of:

(i) Pre-Existing Hazardous Material on the Job Site, other than as set forth in Section 3.16.1(d); and

(ii) Any waste, rubbish or Hazardous Material caused by FPL or its representatives.

3.10 OBTAINING, MAINTAINING AND IDENTIFYING PERMITS

3.10.1 Contractor shall, and shall cause its Subcontractors to comply with, all Applicable Permits, including FPL Permits and Contractor Permits. Contractor shall timely obtain and maintain all Contractor Permits. In addition, Contractor shall timely prepare and submit to the applicable Government Authority all engineering and construction related submittals, reports and other items (including those set forth in Appendix A, Scope of Work) required to maintain and comply with any FPL Permit and provide all assistance reasonably requested by FPL in connection with FPL's efforts to obtain the FPL Permits, including, without limitation, witnesses testimony, depositions, preparation and submission of exhibits, reports or submittals, technical calculations and attending meetings; provided that FPL shall provide Contractor, at no cost to FPL, with all information, documentation and assistance reasonably requested by Contractor to permit Contractor to comply with the provisions of this Section 3.10.1. In the event that any Applicable Permit is required for the Plant or to perform the Work that is not identified in the Contract Documents, Contractor or FPL, as applicable, shall promptly, after it becomes aware of the need for such Applicable Permit, notify the other Party that such Applicable Permit is required. If such permit is of a nature typically obtained by contractors in power projects, Contractor shall, at its sole cost and expense, be obligated to obtain and maintain such Applicable Permit on behalf of FPL. Otherwise, FPL shall obtain and maintain such Applicable Permit.

3.10.2 All Applicable Permits (other than any building permits (but excluding any applicable occupancy certificates) or other Applicable Permits designated as either "To be issued in the name of Contractor" or "To be issued in the name of FPL and Contractor" on Appendix A, Scope of Work, or Appendix M, FPL Permits) shall be issued in the name of FPL unless otherwise required by Applicable Law or such Applicable Permit. If any Contractor Permit (or application therefor) is in the name of FPL or otherwise requires action by FPL, FPL shall, upon the request of Contractor, sign such application or take such action as reasonably appropriate.

3.10.3 FPL reserves the right to review any such application of Contractor; provided, however, that FPL's exercise of such right shall not under any circumstances be considered an approval of the necessity, effect or contents of such application or related permit. Contractor shall deliver to FPL true and complete copies of all Applicable Permits obtained by Contractor upon its receipt thereof. Contractor shall use best efforts to identify in writing to FPL all Applicable Permits and other government requirements for performance of the Work not identified in the Contract Documents, or shall confirm in writing that, to the best of Contractor's knowledge, there are no such Applicable Permits or other government requirements other than as identified in the Contract Documents prior to the date of this Agreement.

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3.11 LABOR.

3.11.1 *General.* Contractor shall be responsible for retaining all Labor necessary for it to perform its obligations hereunder and comply with the provisions hereof, all in accordance with Applicable Laws. Contractor shall be responsible for all costs incurred in complying with this Section 3.11, or otherwise associated with its Labor, including, without limitation, costs incurred by any member of its Labor, whether by direct contract or subcontract, for medical treatment, transport and accommodation as a result of injuries or illness arising from engagement or employment in the execution of the Work.

3.11.2 *Engagement of Labor.* Contractor shall make its own arrangements for the engagement of all Labor in connection with the Contract Documents and the performance of the Work. Contractor shall employ in the performance of the Work only Labor, whether supervisors, skilled workers or laborers, who are competent to perform their assigned duties in a safe and secure manner and shall use all reasonable efforts to cause its Subcontractors and Vendors to adhere to the same standard with respect to their Labor. Contractor agrees, where required by Applicable Law, to employ only licensed personnel in good standing with their respective trades and licensing authorities to perform engineering, design, architectural and other professional services in the performance of the Work. All such professional services shall be performed with the degree of care, safety, skill and responsibility customary among such licensed personnel. All Labor shall have received formal documented training, to the extent required by Applicable Standards, in their area of expertise and, if applicable, certification.

3.11.3 *Identification.* Contractor shall identify each member of its and its Subcontractor's and Vendor's Labor in accordance with the standards and procedures that are mutually acceptable to the Parties.

3.11.4 *Supply of Services for Labor.* Contractor shall provide and maintain at the Job Site, in accordance with Applicable Laws and Applicable Permits, such accommodations, services and amenities as necessary for all Labor employed for the purpose of or in connection with the Contract Documents, including all water supply (both for drinking and other purposes), electricity supply, sanitation, safety, security, fire prevention and fire-fighting equipment, refuse disposal systems and other requirements in connection with such accommodations or amenities.

3.11.5 *Alcohol and Drugs.* Contractor shall not possess, consume, import, sell, give, barter or otherwise dispose of any alcoholic beverages or drugs (excluding drugs for proper medical purposes and then only in accordance with Applicable Law) at the Job Site, or permit or suffer any such possession, consumption, importation, sale, gift, barter or disposal by its Subcontractors, agents or Labor and shall at all times assure that the Job Site is kept free of all such substances. Contractor shall immediately identify and remove from its or its Subcontractors' employment at the Job Site any person (whether in the charge of Contractor or any Subcontractor) who is in possession of or under the influence of any dangerous or controlled drug, alcohol or other such substance at any time during such person's performance of any portion of the Work, excluding any person using a prescription drug under supervision and approval from a medical doctor, or any other person who does or whose actions may create any unsafe condition or other situation that may cause damage or harm to any person or property.

3.11.6 *Arms and Ammunition.* Except as required for Job Site security, Contractor shall not possess, give, barter or otherwise dispose of, to any person or persons, any arms or ammunition of any kind at the Job Site, or permit or suffer the same as aforesaid and shall at all times assure that the Job Site is kept free from arms and ammunition.

3.11.7 *Disorderly Conduct.* Contractor shall be responsible for the conduct and deeds of its Labor and its Subcontractors' Labor relating to the Contract Documents and the consequences thereof. Contractor shall at all times take all reasonable precautions to prevent any unlawful, riotous or disorderly conduct by or among such Labor and for the preservation of peace, protection and safety of Persons and property in the area of the Job Site against the same. Contractor shall not interfere with any members of any authorized police, military or security force in the execution of their duties.

3.11.8 *General Management of Employees.* Subject to FPL's rights as set forth in Section 3.11.11, Replacement at FPL's Request, Contractor shall preserve its rights to exercise and shall exercise its management rights in

performing the Work. Such management rights shall include the rights to hire, discharge, promote and transfer employees; to select and remove foremen or other persons at other levels of supervision; to establish and enforce reasonable standards of production; to introduce, to the extent feasible, labor saving equipment and materials; to determine the number of craftsmen necessary to perform a task, job or project; and to establish, maintain and enforce rules and regulations conducive to efficient and productive operations.

3.11.9 *Labor Disputes*. Contractor shall use reasonable efforts to minimize the risk of labor-related delays or disruption of the progress of the Work. Contractor shall promptly take any and all reasonable steps that may be available in connection with the resolution of violations of collective bargaining agreements or labor jurisdictional disputes, including the filing of appropriate processes with any court or administrative agency having jurisdiction to settle, enjoin or award damages resulting from violations of collective bargaining agreements or labor jurisdictional disputes. Contractor shall advise FPL promptly, in writing, of any actual or threatened labor dispute of which Contractor has knowledge that might materially affect the performance of the Work by Contractor or by any of its Subcontractors or Vendors. Notwithstanding the foregoing, the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the discretion of the Party having the difficulty, except as expressly provided for in Section 14.1, Definition of Force Majeure Event.

3.11.10 *Personnel Documents*. Contractor shall ensure that all its personnel and personnel of any Subcontractors or Vendors performing the Work are, and at all times shall be, in possession of all such documents (including, without limitation, visas, driver's licenses and work permits) as may be required by any and all Applicable Laws.

3.11.11 *Replacement at FPL's Request*. Within one (1) day after request by FPL, Contractor shall remove from the Job Site and performance of the Work, and shall cause any Subcontractor or Vendor to remove from the Job Site and performance of the Work, any Person performing the Work whom FPL determines, in its sole discretion, to be creating a safety hazard or a material risk of either: (i) non-achievement of Mechanical Completion or Provisional Acceptance; or (ii) material non-performance by Contractor in accordance with this Agreement. In addition, Contractor shall include in each subcontract a provision that requires each Subcontractor and Vendor to remove any employee or independent contractor of such Subcontractor or Vendor used in the Work or in such Subcontractor's and Vendor's warranty obligations within one (1) day after receiving notice from FPL to remove such employee or independent contractor.

3.12 PROJECT MANAGEMENT AND CONTRACTOR'S REPRESENTATIVE.

3.12.1 *Project Management*. Contractor has designated a management team as set forth on Appendix O, Project Management Team, and any future members of the management team must be approved by FPL in writing prior to his/her designation, which approval shall not be unreasonably withheld. During the performance of the Work from the Initial Site Mobilization and thereafter, Contractor shall maintain continuously at the Job Site adequate management, supervisory, administrative, security and technical personnel, including the Contractor Site Manager, to ensure expeditious and competent handling of all matters related to the Work, according to its determination of the staffing required for this purpose. Contractor will not re-assign, remove or replace the Contractor Project Manager, Contractor Project Engineering Manager or Contractor Site Manager without FPL's prior written consent, which consent shall not be unreasonably withheld. Contractor shall promptly replace its Contractor Project Manager, Contractor Project Engineering Manager or Contractor Site Manager, upon written request of FPL, if such individual is disorderly or if in FPL's opinion, such individual is otherwise incompetent for his position and responsibilities.

3.12.2 *Contractor's Representative*. Contractor shall appoint one individual (the "Contractor's Representative"), with the prior written consent of FPL, which shall not be unreasonably withheld, who shall be authorized to act on behalf of Contractor and with whom FPL may consult at all reasonable times, and whose instructions, requests and decisions in writing will be binding upon Contractor. Contractor shall not remove or replace such representative without prior written notice to FPL.

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3.13 TEMPORARY OFFICE QUARTERS.

3.13.1 During the performance of the Work from the Initial Site Mobilization and thereafter, Contractor shall maintain, at a reasonable location designated by FPL, a suitable office at the Property Site at or near the site of the Work which shall be the headquarters of Contractor's Representative designated pursuant to Section 3.12, Project Management and Contractor's Representative, above.

3.13.2 Contractor shall provide FPL's representatives with office space, including all utilities, heating, ventilation and air conditioning, contemporaneously with the existence of Contractor's site office specified in paragraph (a) above, which office space shall be subject to the approval of FPL and be in compliance with the requirements therefore in Appendix A, SCOPE OF WORK. Contractor shall properly maintain such offices and shall employ sufficient personnel to clean such office each working day that such offices are used. Contractor shall be responsible for paying all utility deposits and charges, other than long distance telephone charges related to calls made by FPL and its representatives, related to such offices for FPL.

3.14 COOPERATION WITH OTHER CONTRACTORS/COMMUNITY.

3.14.1 Contractor acknowledges that work may be performed by others at the Job Site during the execution of Work under this Agreement. Contractor further acknowledges that FPL, through itself or through its employees, subcontractors or agents, will continue to work and perform activities in connection therewith at and around the Job Site during the execution of the Work under this Agreement. Contractor shall cooperate and cause its Subcontractors and Vendors to cooperate with FPL and other unrelated contractors who may be working at or near the Job Site in order to assure that neither Contractor, nor any of its Subcontractors or Vendors unreasonably hinders or increases, or makes more difficult than necessary the work being done by FPL and other unrelated contractors. Contractor agrees to perform the Work in full cooperation with such others and to permit, without charge, reasonable access to, and use of, the Job Site and the Work, by said others or by FPL, whether such Work is partially or entirely complete, when, in the judgment of FPL, such access or use is necessary for the performance and completion of the work of others. All material and labor shall be furnished, and the Work performed, at such time or times as shall be for the best interest of all contractors concerned, to the end that all Work, and the work of any separate contractor, will be properly coordinated and completed in accordance with the applicable schedules and the times of completion required by the Contract Documents.

3.14.2 In addition to complying with all Applicable Laws and Applicable Permits, Contractor shall use reasonable efforts, and cause its Subcontractors and Vendors to use their reasonable efforts, to assist FPL in creating, assessing and carrying out programs which shall, during all phases of the Work, minimize the impacts upon the host community caused by the construction of the Project. Such programs shall include: (i) sequencing of the Work so as to minimize the impacts of noise and dust at and around the Job Site; and (ii) using local labor and other resources whenever possible and cost effective.

3.15 PROTECTION AND SAFETY.

3.15.1 Prior to the Provisional Acceptance Date, Contractor shall be responsible for the security, protection and safety of all Persons (including members of the public and the employees, agents, contractors, consultants and representatives of FPL, the Financing Parties, Contractor and its Subcontractors and Vendors, and other contractors and subcontractors) and all public and private property (including structures, sewers and service facilities above and below ground, along, beneath, above, across or near the Job Site) that are at or near the Job Site or that are in any manner affected by the performance of the Work. As of the Provisional Acceptance Date, FPL shall have operational control over the Project. Notwithstanding the foregoing, Contractor shall remain responsible for the security, protection and safety of all Persons performing any portion of the Work at the direction of Contractor as well as any damage to property caused directly or indirectly by Contractor's negligent acts or omissions and/or failure to comply with the provisions of the Contract Documents while on the Job Site.

3.15.2 Contractor shall initiate and maintain reasonable safety precautions and accident prevention programs for the Job Site and in the performance of the Work, which shall be in compliance with all Applicable Laws and Applicable Permits, to prevent injury to persons or damage to property on, about or adjacent to the Job

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Site and in the performance of the Work. Without limiting the generality of the foregoing, Contractor shall furnish and maintain all necessary safety equipment such as barriers, signs, warning lights and guards as required to provide adequate protection to persons and property. In addition, Contractor shall give reasonable notice to owners of public and private property and utilities when such property is susceptible to injury or damage through the performance of the Work and shall make all necessary arrangements with such owners relative to the removal and replacement of protection of such property or utilities.

3.15.3 Contractor shall provide FPL, within five (5) Days following its occurrence, with written:

(a) Notification of all Occupational Safety and Health Act recordable events;

(b) Notifications and copies of all citations by Government Authorities concerning accidents or safety violations at the Job Site;

(c) Reports of near misses at the Job Site; and

(d) Copies of written accident reports for lost time accidents.

Contractor shall promptly deliver to FPL any written communication with any Government Authority or insurance company (including any notices) with respect to accidents that occur at the Job Site.

3.16 ENVIRONMENTAL MATTERS.

3.16.1 *Hazardous Material.* Contractor shall, and shall cause its Subcontractors and Vendors to, comply with all Applicable Laws relating to Hazardous Material and all Applicable Permits. Without limiting the generality of the foregoing:

(a) Contractor shall, and shall cause its Subcontractors and Vendors to, apply for, obtain, maintain and renew all Contractor Permits, and comply with all Applicable Permits, in any case, as required by Applicable Laws regarding Hazardous Material that are necessary, customary or advisable for the performance of the Work. Contractor shall, and shall cause its Subcontractors and Vendors to, have an independent Environmental Protection Agency identification number for disposal of Hazardous Material under the Contract Documents if and as required under Applicable Laws or Applicable Permits.

(b) Contractor shall conduct its activities under the Contract Documents, and shall cause each of its Subcontractors to conduct its activities, in a manner designed to prevent pollution of the environment or any other release of any Hazardous Material by Contractor and its Subcontractors and Vendors in a manner or at a level requiring remediation pursuant to any Applicable Law.

(c) Contractor shall not cause or allow the release or disposal of Hazardous Material at the Job Site, bring Hazardous Material to the Job Site, or transport Hazardous Material from the Job Site, except in accordance with Applicable Law and Applicable Permits. Contractor shall be responsible for the management of and proper disposal of all Hazardous Material brought onto or generated at the Job Site by it or its Subcontractors or Vendors, if any. Contractor shall cause all such Hazardous Material brought onto or generated at the Job Site by it or its Subcontractors or Vendors, if any, to be:

(i) Transported only by carriers maintaining valid permits and operating in compliance with such permits and laws regarding Hazardous Material pursuant to manifest and shipping documents identifying only Contractor as the generator of waste or person who arranged for waste disposal; and

(ii) Treated and disposed of only at treatment, storage and disposal facilities maintaining valid permits operating in compliance with such permits and laws regarding Hazardous Material, from which, to the best of Contractor's knowledge, there has been and will be no release of Hazardous Material.

(iii) Contractor shall submit to FPL a list of all Hazardous Material to be brought onto or generated at the Job Site prior to bringing or generating such Hazardous Material onto

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or at the Job Site. Contractor shall keep FPL informed as to the status of all Hazardous Material on the Job Site and disposal of all Hazardous Material from the Job Site.

(d) If Contractor or any of its Subcontractors or Vendors releases any Hazardous Material on, at, or from the Job Site, or becomes aware of any Person who has stored, released or disposed of Hazardous Material on, at, or from the Job Site during the Work, Contractor shall immediately notify FPL in writing. If Contractor's Work involved the area where such release occurred, Contractor shall immediately stop any Work affecting the area. Contractor shall, at its sole cost and expense, diligently proceed to take all necessary or desirable remedial action to clean up fully the contamination caused by any:

(i) Release by Contractor or any of its Subcontractors or Vendors of any Pre-Existing Hazardous Material; and

(ii) Hazardous Material that was brought onto or generated at the Job Site by Contractor or any of its Subcontractors or Vendors, whether on or off the Job Site.

(e) If Contractor discovers any Pre-Existing Hazardous Material that has been stored, released or disposed of at the Property Site, Contractor shall immediately notify FPL in writing. If Contractor's Work involves the area where such a discovery was made, Contractor shall immediately stop any Work affecting the area and FPL shall determine a reasonable course of action. Contractor shall not, and shall cause its Subcontractors and Vendors to not, take any action that may exacerbate any such contamination.

(f) Contractor shall be solely responsible for remedial action to clean up fully the contamination referenced in Section 3.16.1(d). If so requested by FPL, Contractor shall cooperate with and assist FPL in making the Job Site available for taking necessary remedial steps to clean up any such contamination at FPL's expense as determined in accordance with Section 6.3, CHANGES TO CONTRACT PRICE; DISPUTES, of Article VI, CHANGE ORDERS. Contractor shall promptly deliver to FPL any notice or violation, letter of non-compliance or similar communication from any Government Authority.

3.16.2 *Waste Treatment and Disposal*. Without limiting the foregoing:

(a) *Toxic Waste and Industrial Hazards:* Contractor shall be responsible for the proper management and disposal of all toxic waste and industrial hazards brought onto or generated at the Job Site by it or its Subcontractors or Vendors, if any. Contractor shall, and shall cause its Subcontractors and Vendors to, comply with all Applicable Laws, Applicable Permits and applicable safety standards related to the treatment, storage, disposal, transportation and handling of toxic wastes and industrial hazards. Contractor shall not store or dispose of toxic wastes and industrial hazards near groundwater, surface water or drainage systems. Liquid wastes shall not be dumped onto the ground or in any groundwater, surface water or drainage systems. All waste oil and grease resulting from construction activities shall be collected and disposed of in a manner that prevents contamination to soil, ground water, and surface water, and incinerated if possible. Vehicle maintenance shall be conducted in safe areas away from watercourses and oil or fluid runoff shall be collected in grease traps. Toxic waste and industrial hazard storage containers shall be well-labeled.

(b) *Sanitary and Solid Waste:* Contractor shall take appropriate measures in accordance with the Applicable Law and Applicable Permits for the treatment and disposal of sanitary and solid waste, and in particular, Contractor shall perform the Work in such a manner so as to protect environmentally sensitive areas and water supplies. Run-off from disposal sites shall be curtailed.

3.16.3 *Fuel Storage*. The location, facilities, safety measures and environmental and pollution control in connection with storage of fuel or like substances shall comply with all Applicable Laws and Applicable Permits.

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3.16.4 *Protected Areas*. Contractor acknowledges that portions of the Property Site may be wetlands or other protected areas ("Protected Areas") as indicated on the survey to be provided by FPL pursuant to Section 4.7, DESCRIPTION OF PROPERTY SITE, of Article IV, CERTAIN OBLIGATIONS OF FPL. Certain of these Protected Areas, if designated on such survey, do not constitute a part of the Job Site. Contractor shall erect a temporary barrier or other blockade to isolate Protected Areas and protect such areas from impact by any Work. Contractor shall not allow any Work to be conducted in or otherwise interfere with or impact such Protected Areas. Contractor shall, and shall cause its Subcontractors and Vendors to, comply with the Environmental Resource Plan and all permits, rules, regulations and all other Applicable Laws and Applicable Permits in connection with the Protected Areas on or adjacent to the Property Site.

3.17 FIRE PREVENTION.

3.17.1 Contractor shall be responsible for providing adequate fire prevention and protection at the Job Site and shall take all reasonable precautions to minimize the risk of fire at the Job Site. Contractor shall provide instruction to the Labor in fire prevention control and shall provide appropriate fire-fighting and fire protection equipment and systems at the Job Site.

3.17.2 Contractor shall promptly collect and remove combustible debris and waste material from the Job Site in accordance with Applicable Laws and Applicable Permits, and shall not permit such debris and material to accumulate. Contractor shall control the usage of fires for any purpose in the vicinity of the Work and shall agree upon the appropriateness of any such fires with FPL. Any areas of vegetation damaged by fire which are reasonably determined by FPL to have been initiated by Contractor's or Subcontractors' Labor shall be recultivated and otherwise rehabilitated by Contractor, at Contractor's expense.

3.17.3 Contractor will complete all systems, procedures and Equipment constituting the Plant fire protection system as necessary during construction to protect Work in progress, in particular with regard to fuel and other flammable materials.

3.18 RELIGIOUS AND ARCHAEOLOGICAL RESOURCES

In the event any archaeological or religious sites, places, monuments or areas are discovered or identified by Contractor during the performance of Work under the Contract Documents, Contractor shall leave such sites untouched and protected by fencing and shall immediately stop any Work affecting the area. Contractor shall notify FPL of any such discovery as soon as practicable, and Contractor shall carry out FPL's instructions for dealing with the same. All fossils, coins, articles of value or antiquity and structures and other remains or things of geological, archaeological, historical, religious, cultural or similar interest discovered on the Job Site shall, as between FPL and Contractor, be deemed to be the absolute property of FPL. Contractor shall prevent its and its Subcontractors' and Vendors' Labor and any other Persons from removing or damaging any such article or thing.

3.19 REPORTS, PLANS AND MANUALS.

3.19.1 *Status Reports*. Within ten (10) days after the beginning of each month, commencing with the month following the date of this Agreement, Contractor shall prepare and submit to FPL written progress reports, in accordance with the requirements of Appendix B, Project Schedule and Reporting Requirements, which include a description of the progress and status of the Work compared to the Project Schedule, the status of Equipment and other scheduled deliveries, the Subcontractors' activities and engineering, procurement and construction progress. In addition, each such progress report will provide cost information regarding backcharges and a summary of any Changes executed by the Parties as of the date of such report. A reasonable number of photographs shall also be included reasonably documenting the construction progress. Each photograph shall show the date, Contractor's name and description of the view taken. In accordance with Section 5.3, PROJECT SCHEDULE, of Article V, PROJECT SCHEDULE, Contractor shall also report any events which may affect the Project Schedule, including any Force Majeure Events, liens on the Property Site or the Project, or any asserted violations of Applicable Laws.

3.19.2 *Reporting of Accidents*. Contractor shall report in writing to FPL (and, to the extent required by any Applicable Law or Applicable Permit, the appropriate Government Authority) details of any significant safety event or accident required to be reported under U.S. Department of Labor Occupational Safety &

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Health Administration standards that is on or about the Job Site as soon as possible after its occurrence, but in any event not later than forty-eight (48) hours after such accident occurs. In the case of any fatality or serious injury or accident, Contractor shall, in addition, notify FPL (and, to the extent required by any Applicable Law or Applicable Permit, the appropriate Government Authority) immediately.

3.19.3 *Procedures Manual.* No later than forty-five (45) days following the date hereof, Contractor shall prepare and submit to FPL a procedures manual that describes the administrative procedures to be used by Contractor and FPL for interfacing during the performance of the Work (the "Procedures Manual"). Contractor shall either promptly make changes to the Procedures Manual suggested by FPL or negotiate and resolve in good faith with FPL such changes. Upon approval of the Procedures Manual by the Parties, the Parties shall comply with the provisions thereof. The Procedures Manual may be changed from time to time with the approval of the Parties. Contractor shall provide six (6) copies, as well as an electronic copy, of the Procedures Manual to FPL.

3.19.4 *Health Plan, Safety Plan and Environmental Plan.* No later than thirty (30) days prior to Initial Site Mobilization, Contractor shall prepare and submit to FPL:

(a) A health plan that includes health, first aid facility/area with qualified attendant and emergency procedures to be used at the Job Site (the "Health Plan");

(b) An environmental plan (the "Environmental Plan" as more particularly described in Appendix A, Scope of Work) that includes:

(i) A Hazardous Material, waste and industrial hazards management and disposal program which details the controlled usage and treatment of all Hazardous Material, toxic wastes, industrial hazards, sanitary waste, solid waste and other waste brought onto, used or produced at the Job Site or in relation to the Work and outlines a management structure for carrying out the specific provisions of such program;

(ii) An environmental protection and management program, including, without limitation, a sediment and erosion control program

(iii) A revegetation program, with a Change Order related thereto; and

(iv) The description, location and drawings of construction facilities and temporary works; and

(c) A safety plan substantially in the form of Appendix Z, Form of Safety Plan, which shall include an acknowledgement by Contractor that Contractor shall at all times remain in compliance with all federal, state and local safety codes (the "Safety Plan").

Each of the Health Plan, Environmental Plan and Safety Plan shall be consistent with all Applicable Laws and Applicable Permits and shall be submitted to FPL for review and comment. Contractor shall either promptly make changes to such Health Plan, Environmental Plan or Safety Plan incorporating the comments of FPL or negotiate and resolve in good faith with FPL any such changes. Contractor shall comply and ensure that its Subcontractors comply with the Health Plan, Environmental Plan, Safety Plan, the Safe and Secure Workplace Policy, the Project Loss Manual and the Environmental Control Program.

3.19.5 *Meetings.* During the performance of the Scope of Work, Contractor and FPL shall, at a minimum, conduct meetings each month at a mutually convenient time and date for the purpose of reviewing the progress of the Scope of Work, the latest progress reports, the Health Plan, the Environmental Plan, the Safety Plan, Quality Assurance Program, Contractor's and Subcontractors' adherence to the Scope of Work and the Project Schedule as well as the status of any claims on the Project and claims submitted pursuant to the terms of the Contract Documents. Contractor shall prepare detailed minutes of each such meeting, in form and content acceptable to FPL, and shall distribute same to FPL within five (5) days after such meeting.

3.19.6 *Contractor Not Relieved of Duties or Responsibilities.* Neither the submission to or approval by FPL of progress and other reports, plans and manuals, nor the provision of general descriptions shall relieve Contractor of any of its duties or responsibilities under the Contract Documents.

3.19.7 *Quality Assurance Program.*

(a) Contractor shall use effective quality assurance programs (collectively, the "Quality Assurance Program"), which such programs:

(i) Propose the manner in which Contractor intends to achieve the highest standards in the performance of the entire Scope of Work;

(ii) Shall be acceptable to FPL; and

(iii) Shall be consistent with the requirements of Appendix Y, Form of Quality Assurance Programs, and Appendix A, Scope of Work, in performing the Work.

(b) Within thirty (30) days after the date of this Agreement, Contractor shall provide to FPL a description of the Quality Assurance Program, which shall be substantially in the form of Appendix Y, Form of Quality Assurance Programs, (the "Quality Control Manual"), to be used by Contractor in the performance of the Work. The Quality Control Manual shall also include all proposed types of Critical Parameters that Contractor shall define as the Scope of Work progresses. "Critical Parameters" are defined as construction critical dimensions, commissioning critical set-points, critical alignments and process critical set-ups for Equipment, sub-systems, systems and the Plant, as mutually agreed to by the Parties.

(c) As soon as the Critical Parameters have been finalized, Contractor shall include the same in the Project Schedule. Contractor shall provide FPL with tentative dates for the performance of Critical Parameters, which dates shall be updated monthly, and shall also provide FPL with twenty-four (24) hour written notice prior to performance of any Critical Parameters. FPL will review and provide comments to such programs in writing within thirty (30) days after submission by Contractor.

(d) If FPL's comments are reasonable changes to the quality assurance programs submitted by Contractor, Contractor will effect such changes at no additional cost to FPL and resubmit such programs to FPL within ten (10) days after Contractor receives FPL's comments. FPL will have ten (10) days after such resubmission to review and provide comments to such programs resubmitted by Contractor. Such procedure shall continue with the same ten (10) day time periods until FPL accepts such programs. If FPL fails to respond within any of the applicable periods specified above, FPL shall be deemed to have agreed to the last such programs submitted by Contractor. If applicable, Contractor shall also submit verification of ISO 9001 qualification.

(e) Contractor's program shall address how improvement actions will be applied on the Project's processes, products and services. Contractor shall also have in place a formal system of collecting, reviewing and evaluating corrective and preventive actions from a lessons learned process that will ensure desirable changes regarding engineering, procurement, construction, start-up, turnover or operation feedback from recently completed (or in process projects) are incorporated.

(f) A post award (pre-production) meeting shall be held at Contractor's facility to demonstrate Contractor's understanding of the quality and quality assurance requirements, and present their methods of complying with these requirements.

3.20 DRAWINGS, ENGINEERING DATA AND OTHER MATERIALS.

3.20.1 All Drawings, Final Plans, reports and other information (except financial, accounting and payroll records) furnished to Contractor, or prepared by it, its Subcontractors or others in connection with the performance of the Work, whenever provided, shall be kept by Contractor in an orderly and catalogued fashion for reference by FPL during the performance by Contractor of the Work. Contractor shall maintain at the Property Site at least one (1) copy of all Drawings, Final Plans, Change Orders and other modifications in good order and marked to record all changes made during performance of the Work, including, without limitation, all field deviations from the construction drawings. As a condition precedent to Final

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Acceptance, or upon the earlier termination of this Agreement, Contractor shall transfer the Final Plans to FPL and they shall become the sole property of FPL.

3.20.2 Final Plans (in both hard copy and magnetic media at no extra charge to FPL), if not furnished earlier, shall be furnished to FPL upon Contractor's request for a Final Acceptance Certificate or upon the earlier termination of this Agreement. Contractor and any of its Subcontractors, as applicable, may retain copies all such documents for their records, subject to the confidentiality provisions of this Agreement.

3.20.3 Within ninety (90) days after the date of this Agreement, Contractor shall furnish FPL (in electronic format whenever available) with conceptual engineering drawings and the specifications pertaining to the electric generators and step-up transformers of the Plant, including demonstrations that the:

(a) Requirements for reactive supply facilities at the Plant will be met; and

(b) Plant will meet the guidelines and performance standards set forth in the Contract Documents and the Operating Guidelines.

3.20.4 Contractor shall submit all Drawings in electronic format to FPL in accordance with Appendix A, Scope of Work, for review and comment as provided in the Scope of Work. Based upon FPL's comments, if any, Contractor shall resolve FPL's comments. Contractor shall revise such Drawings from time to time, as required to reflect any changes, in the actual installation of any individual Equipment or system or the Plant as a whole. Notwithstanding anything contained herein to the contrary, FPL's review and/or acceptance of the Drawings, or any portion thereof, shall not in any way relieve Contractor of any of its obligations or warranties set forth herein, including, but not limited to, its full responsibility for the accuracy of the dimensions, details, integrity and quality of the Drawings.

3.21 OPERATING AND MAINTENANCE MANUALS

Contractor shall supply FPL with manuals and/or handbooks (in electronic format) which provide, either in a single manual or handbook or collectively, complete operating and maintenance instructions (including inventories of spare parts and tools and parts lists with ordering instructions) for each major piece of Equipment and system of the Plant. Each such manual and handbook shall comply with the requirements of the Scope of Work and the guidelines contained in Appendix L, including with respect to matters such as quantity, content and the time when such manuals are to be supplied to FPL, and shall be substantially complete and delivered to FPL prior to Mechanical Completion in order to support training of personnel and start-up and testing of the Plant.

3.22 TRAINING OF O&M PERSONNEL.

3.22.1 During the construction of the Plant, and at least ninety (90) days prior to the Provisional Acceptance Date, Contractor shall provide, at its own expense, a training program in Plant operation and maintenance for FPL's Plant personnel and the O&M Contractor's Plant personnel (collectively, "O&M Personnel"). The training program provided by Contractor shall be subject to FPL's prior written approval and shall:

(a) Include classroom and field training;

(b) Include all manuals, drawings, and other educational materials necessary or desirable for the adequate training of O&M Personnel; and

(c) Establish quality controls so that O&M Personnel are suitably trained and capable of operating and maintaining the Plant after Provisional Acceptance.

Representatives of manufacturers of Equipment shall be utilized to provide specialized training for such Equipment where deemed necessary by the Parties. All training programs conducted in accordance with this Section 3.22, shall be videotaped and made available to FPL in electronic format.

3.22.2 Contractor shall make every reasonable effort to use the O&M Personnel during Plant start-up and initial operation; however, neither FPL nor O&M Contractor shall be obligated to:

(a) Supply personnel for the construction of the Plant; nor

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(b) Provide during Plant start-up and initial operation more O&M Personnel than the number of O&M Personnel FPL and O&M Contractor would use during normal Plant operation as determined by FPL. Contractor shall have complete responsibility for directing, coordinating, monitoring and supervising O&M Personnel during Plant start-up and initial Plant operations.

3.22.3 In addition, Contractor shall:

(a) Remain solely responsible for performing the Work in accordance with this Agreement, including Contractor's obligation to achieve Mechanical Completion, achieve Provisional Acceptance by the Guaranteed Provisional Acceptance Date and achieve Final Acceptance, regardless of any act, omission, failure, non-achievement, or non-performance of the O&M Personnel;

(b) Remain fully responsible for all acts and omissions of the O&M Personnel in connection with the commissioning and operation of the Plant until the Provisional Acceptance Date as fully as if Contractor had independently engaged such O&M Personnel; and

(c) Be responsible for all acts and omissions of the O&M Personnel after the Provisional Acceptance Date if such acts or omissions are taken at the direction of Contractor.

3.22.4 The cost of the O&M Personnel's travel, lodging, food and other living expenses shall be borne by FPL. Contractor shall have the right to require FPL to remove O&M Personnel from the Job Site if Contractor reasonably believes that any such O&M Personnel is unable to properly perform its obligations in connection with the commissioning and operation of the Plant and Contractor provides FPL a written explanation of its reasons for exercising the removal rights granted to it hereunder; provided that the failure of such O&M Personnel to perform their obligations or the removal of any O&M Personnel pursuant to this Section 3.22, shall not relieve Contractor of any of its obligations hereunder.

3.23 ACCOUNTING INFORMATION; FINANCIAL REPORTING REQUIREMENTS

3.23.1 During the term of this Agreement and continuing for five (5) years after the Final Acceptance Date, Contractor will provide FPL with any reasonably necessary assistance, including providing all documents, cost information and other information that FPL believes necessary, in a form reasonably acceptable to FPL, for FPL's federal, state or local tax filings, exemptions or positions advocated by FPL, including, without limitation, sales, use and property taxes; provided, however, that such access to cost information not otherwise made available to FPL pursuant to the terms hereof shall be disclosed to an independent auditor of FPL's choice that agrees to keep secret from FPL, Contractor's cost and other competitively sensitive information.

3.23.2 Unless otherwise publicly available, Contractor shall as soon as available, but in any event within sixty (60) days after each of the first three (3) quarters of each calendar year, deliver to FPL a copy of the complete unaudited balance sheet for such quarter for the Contractor Parent Company prepared in accordance with generally accepted accounting principles and certified by the Chief Financial Officer of Contractor Parent Company. Unless otherwise publicly available, Contractor shall as soon as available, but in any event within ninety (90) days after December 31 of each year, deliver to FPL a copy of the complete audited financial statements for such year with an unqualified opinion for the Contractor Parent Company prepared in accordance with generally accepted accounting principles.

3.24 CONTRACTOR TAXES.

3.24.1 Except for FPL Taxes, Contractor shall, as required by applicable law, pay and administer any and all Taxes and duties incurred or payable in connection with the Work, including, without limitation, taxes based on or related to the income, receipts, capital or net worth of Contractor, Contractor's or its Subcontractors' or Vendors' Labor or income, except for FPL Taxes (collectively, "Contractor Taxes"); provided, however, that if Contractor is responsible for payment of FPL Taxes under Applicable Law, unless otherwise instructed by FPL or FPL is contesting such FPL Taxes, Contractor shall pay such FPL Taxes and any penalties and interest due thereon, and FPL shall reimburse Contractor for such FPL Taxes and any penalties and interest due thereon resulting from instructions provided by FPL upon submission of evidence of payment. Contractor shall promptly provide FPL with reports or other evidence reasonably

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acceptable to FPL showing the payment of Contractor Taxes by Contractor and any FPL Taxes required to be paid by Contractor pursuant to this Section 3.24. Contractor shall use commercially reasonable efforts to cooperate with FPL to endeavor to minimize any FPL Taxes. Notwithstanding the foregoing, Contractor agrees to purchase for resale to FPL any machinery or equipment in connection with the Work that would be the type of property that would qualify as manufacturing machinery and equipment entitled to the exemption from the Florida sales and use tax provided under Applicable Laws and, at the direction of FPL, Contractor agrees to take such action as may be reasonably required to allow such property, to the extent possible to qualify for any sales or use tax exemption. If required in connection with the purchase of any such property from its Vendors, to the extent permitted by applicable law, Contractor agrees to provide its Vendors a resale certificate or applicable affidavit as approved by the State of Florida reflecting the fact that Contractor is purchasing such property for resale to FPL. Contractor agrees to take any other action reasonably necessary to ensure that the purchase of qualifying machinery with respect to the Work is exempt from sales and use tax under Florida (or other applicable) law. To the extent Contractor is required by Applicable Law to collect sales tax from FPL, Contractor shall collect sales tax from FPL on all materials physically incorporated in the Plant that are not subject to exemption unless FPL has elected to provide Contractor with a direct pay certificate issued to FPL by the State of Florida, in which case, FPL shall pay such sales tax directly to the State of Florida. In the event that an assessment for sales and/or use or excise taxes are levied against Contractor, any Subcontractor or Vendor, Contractor shall promptly notify FPL and furnish to FPL a copy of such assessment. In the event that FPL determines that the assessment should be contested and so notifies Contractor in writing, FPL may, at FPL's sole cost and expense, file such documents as are necessary to contest such assessment. FPL shall exclusively control any contest, assessment or other action regarding any such taxes or assessments, or any penalties or interest in respect thereof. In addition to Contractor's other obligations as set forth herein, Contractor shall cooperate with and assist FPL, at FPL's expense, in any contest or proceeding relating to Taxes payable by FPL hereunder.

3.24.2 Exempt Equipment. Some of the machinery, equipment, parts or other items of tangible personal property to be incorporated into the Plant may be exempt from certain taxes (such exempt items, the "Exempt Equipment"). FPL and Contractor will work together to determine which purchases constitute purchases of Exempt Equipment, and Contractor and FPL will take reasonably necessary actions to ensure that such Exempt Equipment qualifies for applicable tax exemptions.

3.25 CLAIMS AND LIENS FOR LABOR AND MATERIALS

If FPL is paying when due all undisputed amounts in accordance with the Contract Documents, Contractor shall, at Contractor's sole expense, discharge and cause to be released, whether by payment or posting of an appropriate surety bond in accordance with Applicable Law, within ten (10) days after receipt of a written demand from FPL, any Lien in respect to the Plant, the Contract Documents, the Equipment, the Job Site or any fixtures or personal property included in the Work (whether or not any such Lien is valid or enforceable) created by, through or under, or as a result of any act or omission (or alleged act or omission) of, Contractor or any Subcontractor, Vendor or other Person providing labor or materials within the scope of Contractor's Work. Notwithstanding the foregoing provision, as long as FPL, in its sole discretion, determines that the Job Site and the improvements thereon will not be subject to any liability, penalty or forfeiture, upon the written request of Contractor, FPL may permit Contractor to contest the validity, enforceability or applicability of any such Lien, in which event FPL shall provide, at no cost to FPL, such cooperation as Contractor may reasonably request in connection therewith.

3.26 SPARE PARTS AVAILABILITY.

3.26.1 *Start-up Spare Parts*. Prior to Mechanical Completion, Contractor shall obtain all spare parts required for Plant start-up and testing. All spare parts not used during Plant start-up and testing shall become the property of FPL, it being understood and agreed that additional photovoltaic panels held by Contractor at the Project Site but not incorporated into the Project shall not be deemed to be spare parts.

3.26.2 *Operating Spare Parts*. At least ten (10) days prior to the Provisional Acceptance Date, Contractor shall provide FPL with each manufacturer's recommended spare parts list for the Equipment, which list shall

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include part numbers, recommended quantities, price, mean times to failure, mean times to repair and a description of lead times necessary for orders of such spare parts, in each case to the extent reasonably available to Contractor. Contractor agrees to:

(a) Obtain from each Major Manufacturer an assignable guaranty that such Major Manufacturer will have available for purchase by FPL for a period of five (5) years after the Provisional Acceptance Date, all spare parts for the Major Equipment supplied by such Major Manufacturer required to keep the Plant in good operating condition, it being understood that some of such parts are not "shelf items" and will have to be manufactured by the Major Manufacturer after it receives an order for them;

(b) Make spare parts (other than spare parts for the Major Equipment) available for purchase by FPL for a period of five (5) years after the Provisional Acceptance Date to the extent that Contractor is able to obtain them from the manufacturer who supplied them for the Plant as originally built;

(c) Find another source that can supply such spare parts if Contractor is unable to obtain such spare parts from such manufacturer; and

(d) Obtain a firm price for such spare parts reasonably acceptable to FPL for a period of five (5) years after the Provisional Acceptance Date.

3.26.3 With regard to the spare parts described in paragraph (b) above, upon written notice from FPL at any time prior to the Provisional Acceptance Date, Contractor shall, at FPL's expense but without mark-up or multiplier, purchase and have delivered to the Job Site as soon as possible permanent plant spares. Contractor will pay for and replace such spares if used during start-up and commissioning of the Plant.

3.27 CONTRACTOR'S OBLIGATION TO NOTIFY

Contractor shall keep FPL advised as to the status of the Equipment and Work and shall promptly inform FPL in writing upon the occurrence of any of the following, any:

3.27.1 Occurrence or event that may be expected to impact the schedule for delivery and/or installation of Equipment;

3.27.2 Technical problem not anticipated at the start of the Work or of significant magnitude that may impact the Plant or any component thereof or the Project Schedule;

3.27.3 Defect; and

3.27.4 Material changes to previously submitted information. FPL shall have the right to verify the information provided by Contractor. In connection therewith, Contractor shall identify those items provided to FPL that would enable FPL to verify such information in an expedient manner.

3.28 CONSTRUCTION UTILITIES

Contractor shall be responsible for the cost, supply and availability of electric power and distribution requirements for the performance of the Work at the Job Site for the construction and up to Provisional Acceptance; provided, however, Contractor shall be responsible for the cost of any such items to the extent required in order to reperform any Tests. Contractor shall provide its own telephone, facsimile, radio and other communication facilities at the Job Site as necessary for the performance of the Work. If FPL determines that any Test performed or to be performed by Contractor will result in financial harm to FPL, Contractor will accommodate FPL's reasonable requests to mitigate or alleviate such harm to FPL. In addition, Contractor shall provide, at its sole cost and expense, all chemicals for commissioning, start-up and testing and its own temporary lighting, water and sewer facilities at the Job Site.

3.29 LINES AND GRADES

Contractor shall provide for the proper laying out of the construction Work, for making measurements and for establishing temporary or permanent reference marks in connection with the construction Work and Plant. Contractor shall ensure that all improvements constructed in connection with the Work are constructed within the boundaries of the Property Site as delineated in Appendix P, Legal Description of Property Site,

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and do not encroach on any easements, rights of way or other improvements existing on the Property Site as delineated in Appendix P, Legal Description of Property Site. FPL may at its sole discretion and cost, check the reference marks, lines, grades and measurements so established. Contractor shall carefully preserve all monuments, bench marks and reference points. In case of its destruction thereof, Contractor will be responsible for all damages, costs and expenses related to their replacement and for any mistake or loss of time that may result therefrom. Permanent monuments or bench marks which must be removed or disturbed shall be protected until they can be properly referenced for relocation. Contractor shall furnish materials and assistance for the proper replacement of such monuments or bench marks.

3.30 TEMPORARY STRUCTURES

Temporary structures for offices, quarters, storage and other uses for Contractor, its Subcontractors and Vendors and FPL shall be constructed only in locations approved by FPL. Contractor shall erect temporary walls, bulkheads or fences where required to isolate the construction area from adjacent property in order to increase safety and security and to minimize noise, dust and dirt from affecting the property surrounding the Job Site.

3.31 WEATHERPROOF COVERINGS

Contractor shall provide adequate and sufficient weatherproof and flame resistant coverings for outdoor storage at the Job Site. The cover or sheeting shall be tied down to prevent moisture from damaging the Equipment.

3.32 INTELLECTUAL PROPERTY RIGHTS.

3.32.1 Contractor agrees to grant and hereby grants to FPL an irrevocable, permanent, non-exclusive, royalty-free license to utilize all of Contractor's trade secrets, patents, copyrights, trademarks, proprietary rights or information, licenses and other intellectual property rights (collectively, the "Intellectual Property Rights") and the Intellectual Property Rights of third parties (to the extent of Contractor's rights thereto which can be transferred without violation of obligations owed to such third parties), to the extent now existing or developed primarily for the Project, related to the Work, to the extent reasonably necessary for completion, design, construction, installation, operation, maintenance, repair, or replacement of the Project, or Contractor's expansion, modification, or alteration of the Project (or any subsystem or component thereof designed, specified, or constructed by Contractor under this Agreement).

3.32.2 FPL shall have the right to assign the benefit of such license to any Financing Party in connection with granting a security interest in the Project or any portion thereof, to a purchaser in connection with a transfer of the Project, or to any subsequent purchaser or assignee of same. Any such purchaser or assignee shall acquire such license subject to the same terms and restrictions as stated in this Section 3.32.

3.32.3 Contractor shall, prior to directing any Subcontractor to produce any design or engineering work in connection with the Project, obtain a valid written assignment of all applicable Intellectual Property Rights from such Subcontractor in terms identical to those that obligate Contractor to FPL as expressed in this Section 3.32, which Intellectual Property Rights Contractor hereby assigns to FPL.

3.32.4 Should Contractor or any employee or agent of Contractor make any invention or discovery in connection with performing the Work, such invention or discovery shall be deemed to be the sole and exclusive property of Contractor. To the extent FPL has any right or title thereto or interest therein, FPL hereby assigns (and shall cause the assignment of) all such right and title to, and interest in, any such invention or discovery to Contractor. FPL shall, at Contractor's expense and request, cooperate in pursuing and effecting the transfer to Contractor of all of FPL's right and title to and interest in any such invention or discovery, including, without limitation, executing or causing the execution of assignments and applications, and assign with prosecution and enforcement of rights with respect to any such invention or discovery, including, without limitation, executing patent applications and powers of attorney with respect thereto. Notwithstanding the above, in the event FPL contributes to the joint invention of any invention or discovery in connection with the Project ("FPL Assisted Discoveries"), Contractor hereby grants (and shall grant) to FPL a non-exclusive, royalty-free license to use such FPL Assisted Discoveries for any purpose at any location in the State of Florida.

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3.32.5 This Section 3.32, shall survive the expiration or termination of this Agreement.

3.33 EMERGENCIES

In the event of any emergency that endangers or could endanger life or property, Contractor shall take such action as may be reasonable and necessary to prevent, avoid or mitigate injury, damage or loss and shall, as soon as possible, report any such incidents, including Contractor's response and actions with respect thereto, to FPL.

3.34 [INTENTIONALLY DELETED]

3.35 WASTEWATER, POTABLE WATER

Contractor shall supply at its expense all raw, potable and other water at the Job Site as necessary in connection with the installation, start-up and testing of the Plant. Contractor shall dispose of all wastewater in conformance with Applicable Law and Applicable Permits.

3.36 [INTENTIONALLY DELETED]

3.37 START UP PROCESS

Contractor shall perform the Plant start-up in accordance with the process set forth in Appendix A, Scope of Work. Whenever FPL's staffing situation permits, FPL and Contractor shall mutually agree upon and utilize qualified FPL seconded personnel for start-up leadership positions, including the technical start-up manager and key start-up supervision positions; provided, however, Contractor shall remain fully responsible for all acts and omissions of such personnel in connection with the commissioning and operation of the Plant until the Provisional Acceptance Date as if Contractor had independently engaged such personnel, and be responsible for all acts and omissions of such personnel after the Provisional Acceptance Date if such acts or omissions are taken at the direction of Contractor.

3.38 ACCOMMODATIONS REGARDING TESTING

Contractor shall (excluding any action which will affect Contractor's ability to complete the Work within the time required pursuant to this Agreement or increase Contractor's cost to complete the Work) coordinate with FPL the scheduling of any Test, which efforts may include modification of Contractor's planned test program to maximize the value of energy sold. Contractor shall coordinate such Test with the dispatch schedule for the Plant, so as not to interfere with FPL's or its Affiliates' obligations with respect thereto.

3.39 ACCESS

Contractor shall use only the entrance(s) to the Job Site specified by FPL for ingress and egress of all personnel, equipment, vehicles, and materials. Contractor shall perform the Work consistent and in accordance with FPL's ownership, license and easement rights in and to the Job Site.

3.40 NATURE OF OBLIGATIONS

Except as expressly stated to the contrary herein, the Contract Price includes the cost of completion of all the foregoing obligations. Contractor hereby agrees that it shall be ultimately responsible for the performance of all activities, which may be necessary and desirable for the full performance of the Scope of Work, all in accordance with the Contract Documents.

ARTICLE IV.
CERTAIN OBLIGATIONS OF FPL

4.1 PERMITS

FPL shall, with Contractor's reasonable assistance (to be provided at no cost to FPL), timely obtain and maintain, at its own cost and expense, all FPL Permits. In addition, FPL shall execute such applications as Contractor may reasonably request in connection with obtaining any of the Contractor Permits; provided, that FPL shall provide Contractor with such information and documentation, at no cost to FPL, as Contractor shall reasonably request in order to execute such applications. FPL shall deliver to Contractor evidence that the FPL Permits necessary to begin construction of the Plant have been received by FPL or, if any such

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required FPL Permit has not actually been issued, that it has been approved for issuance, or in the opinion of FPL, will be approved for issuance.

4.2 INTERCONNECTION FACILITIES

At least thirty (30) days prior to the Provisional Acceptance Date, FPL shall give Contractor reasonable access to the FPL Interconnection Facilities.

4.3 FPL OBLIGATIONS IN SCOPE OF WORK

FPL shall comply with each and every obligation and duty assigned to FPL in the Scope of Work.

4.4 [INTENTIONALLY DELETED]

4.5 ACCESS TO PROPERTY SITE

Subject to Section 3.37, START UP PROCESS, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, and consistent with the terms of the Applicable Permits and FPL's ownership, license, and easement rights in and to the Job Site, FPL shall make the Job Site reasonably available to Contractor and its Subcontractors and Vendors and assure reasonable rights of ingress and egress to and from the Job Site for Contractor and its Subcontractors and Vendors for performance of the Work; provided, however, that Contractor shall coordinate with FPL regarding: (i) initial entry onto the Job Site or any part thereof; and (ii) contact with the Persons who own property on or near, or have granted license or easement rights in and to, the Job Site. During the period commencing on the Final Acceptance Date and ending at the expiration of the Warranty Period provided in Section 12.1.4(c), FPL shall make the Job Site reasonably available to Contractor for the sole purpose of monitoring FPL's compliance with operation and maintenance manuals and manufacturers' guidelines applicable to the Equipment in connection with Contractor's satisfaction of its warranty obligations under Article 12, Contractor's Warranties.

4.6 [INTENTIONALLY DELETED]

4.7 DESCRIPTION OF PROPERTY SITE

On or before thirty (30) days after the date of the Agreement, FPL shall deliver to Contractor a boundary survey of the Property Site. Contractor may rely on such boundary survey for the sole purpose of establishing the boundaries of the Property Site.

4.8 NOTICE OF FINANCIAL CLOSING

FPL shall give Contractor prompt written notice of the scheduled and actual date of Financial Closing.

4.9 FPL TAXES

FPL shall pay all real property taxes assessed against the Property Site and any permanent use charges (but excluding charges and taxes for utilities and fuel to be supplied by Contractor as required hereunder, which shall be Contractor's responsibility), and, subject to Section 3.24, CONTRACTOR TAXES, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR FPL, shall be responsible for the payment of, or reimbursement to Contractor of, state or local sales and/or use taxes assessed by the State of Florida (or any city, county or municipality therein) in connection with the purchase of all Equipment, except for such taxes FPL contests in good faith, in each case including any such taxes resulting from a Change In Law (collectively, "FPL Taxes"). In the event that FPL is required to pay additional Taxes, penalties or interest because Contractor failed to follow written instructions of FPL appropriately or to comply with its obligations under Section 3.24, CONTRACTOR TAXES, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR FPL, Contractor shall be responsible for the cost of such additional Taxes, penalties or interest within thirty (30) days of FPL's request therefor.

4.10 FPL'S COOPERATION

At no additional cost to FPL, FPL shall make reasonable efforts to supply to Contractor, in a timely manner, either directly or indirectly, material information and data that is available to FPL and that is required for the performance of the Work; provided, however, FPL does not warrant the correctness of the information and

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documentation provided hereunder. Although FPL may provide or may have provided Contractor with copies of certain studies, reports or other information (including oral statements), Contractor acknowledges and agrees that:

4.10.1 All such documents or information have been or will be provided as background information and as an accommodation to Contractor;

4.10.2 FPL makes no representations or warranties with respect to the accuracy of such documents or the information (including oral statements) or opinions therein contained or expressed; and

4.10.3 It is not relying on FPL for any information, data, inferences, conclusions, or other information with respect to the Job Site (other than the boundary survey referred to in Section 4.7, DESCRIPTION OF PROPERTY SITE), including the surface and subsurface conditions of the Job Site and the surrounding areas.

4.11 FPL'S REPRESENTATIVE

No later than the date of this Agreement, FPL shall designate in writing one or more representatives at the Property Site (at least one of whom shall be at the Job Site during normal business hours) who shall act as the point of contact for both Contractor and the Independent Engineer with respect to the prosecution of the Work, administration of the Contract Documents on behalf of FPL, approval of Contractor's submissions hereunder and inspection of the Work, as reasonably necessary for Contractor's performance of the Work; provided that such representative(s) shall not be authorized to execute or make any amendments to, authorize Change Orders in respect of, or provide waivers under, this Agreement. FPL shall provide Contractor with prior written notice in the event that it designates any additional representatives or removes any existing representatives.

4.12 [INTENTIONALLY DELETED]

4.13 OPERATION AND MAINTENANCE

Subject to Contractor's removal rights set forth in Section 3.22, TRAINING OF O&M PERSONNEL, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, FPL shall, commencing fifteen (15) days prior to the anticipated Provisional Acceptance Date (as determined by FPL based on the circumstances existing at the time of determination), provide O&M Personnel with skills and training appropriate for the operation of a photovoltaic solar power plant reasonably required for training by Contractor as provided in accordance with Section 3.22, TRAINING OF O&M PERSONNEL, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, and for testing, start-up, operation, commissioning, and maintenance of the Project; provided, however, that Contractor shall remain solely responsible for performing the Work in accordance with this Agreement, including Contractor's obligation to achieve Mechanical Completion and Provisional Acceptance on or before the Guaranteed Provisional Acceptance Date, regardless of any act, omission, failure, non-achievement, negligence or non-performance of such O&M Personnel.

ARTICLE V.
PROJECT SCHEDULE

5.1 COMMENCEMENT OF WORK

Prior to the issuance of the Notice to Proceed, Contractor shall commence and diligently pursue completion of the Work only to the extent provided in a Limited Notice to Proceed issued pursuant to Section 5.2.2.

5.2 NOTICE TO PROCEED

5.2.1 *Commencement Date.* Between two to eight (2-8) weeks before Contractor will construct improvements at, or deliver materials to, the Job Site that may be insured pursuant to a Builder's Risk Policy, Contractor shall deliver in writing to FPL a notice setting forth the Commencement Date.

5.2.2 *Limited Notice to Proceed.* Prior to the issuance of the Notice to Proceed, FPL may issue one or more Limited Notices to Proceed; provided, however, if the Limited Notice to Proceed has not been issued by FPL pursuant to Section 5.2.3 below, on or before August 1, 2008 (the "Latest Limited Notice to Proceed Date"), Contractor shall be entitled to a day-for-day extension of the Guaranteed Provisional Acceptance

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Date and all Critical Milestone Dates related thereto for each day after August 1, 2008, that FPL has failed to issue a Limited Notice to Proceed, in each case extension shall be Contractor's sole and exclusive remedy for such failure and Contractor shall not be entitled to claim an FPL Caused Delay with respect to such failure. The date on which FPL provides Contractor with a Limited Notice to Proceed, if at all, pursuant to Section 5.2.3 below, shall be the "Limited Notice to Proceed Date". Any Work described in a Limited Notice to Proceed shall be subject to the terms of this Agreement and Contractor shall commence such portion of the Work after the Limited Notice to Proceed Date set forth therein and thereafter diligently pursue that portion of such Work. Any payment by FPL with respect to such portions of the Work shall be determined and applied to the Contract Price in accordance with Article VII hereof.

5.2.3 *Limitation on Work Prior to Notice to Proceed.* A Limited Notice to Proceed, issued pursuant to this Section 5.2.3, if any, shall authorize Contractor to commence performance of the Work; provided, however, Contractor may not perform any construction activities at the Job Site; and further provided, Contractor shall not enter into any contract, agreement or purchase order (or any obligation or commitment with respect thereto) with a Subcontractor or Vendor without the prior written consent of FPL (which consent may be granted or withheld in FPL's sole discretion).

5.2.4 *Notice to Proceed.* The Business Day after which FPL provides Contractor with the Notice to Proceed shall be the "Notice to Proceed Date"; provided, however, that the Notice to Proceed Date shall not be later than January 1, 2009 (the "Latest Notice to Proceed Date"). On the Notice to Proceed Date, Contractor shall commence and shall thereafter diligently pursue all of the Work assigning to it a priority that should reasonably permit the attainment of Provisional Acceptance on or before the Guaranteed Provisional Acceptance Date. Contractor shall proceed with the performance of the Work in accordance with the Project Schedule.

5.2.5 *Delay in Notice to Proceed.* If a Notice to Proceed has not been issued by the Latest Notice to Proceed Date, and such failure causes an increase in the Contract Price or time required for performance of the Work, then Contractor shall promptly notify FPL thereof in writing and FPL may either (i) issue a Change Order to address such failure in which event the Latest Notice to Proceed Date shall be extended for thirty (30) days and the procedure set forth herein shall be repeated upon the expiration of each additional thirty (30) day period; or (ii) terminate this Agreement pursuant to Section 15.3,and FPL shall only be obligated to pay Contractor an amount equal to any applicable Termination Payment. If this Agreement is terminated pursuant to this Section 5.2.5, then except as set forth in Section 15.3, neither Party shall have any further rights or obligations hereunder (other than such rights and obligations that by the express terms of this Agreement survive the expiration or earlier termination of this Agreement or as otherwise set forth in a Limited Notice to Proceed).

5.3 PROJECT SCHEDULE.

5.3.1 Contractor shall perform the Work in compliance with the Project Schedule, including completing the Work required by the Guaranteed Provisional Acceptance Date and the Final Acceptance Date. Contractor hereby covenants and warrants to FPL that in undertaking to complete the Work in accordance with the terms hereof, Contractor has taken into consideration and made reasonable allowances for hindrances and delays incident to such Work not caused by FPL. Contractor shall provide the reports as required herein, and provide any further information required by FPL as FPL, the Financing Parties or the Independent Engineer may reasonably request to verify actual progress and forecast future progress of the Work. Contractor shall promptly notify FPL in writing of any occurrence that Contractor has reason to believe will adversely affect the completion of the Work by the Guaranteed Provisional Acceptance Date or materially adversely affect completion of the Work in accordance with the Project Schedule. Contractor will specify in said notice the corrective action planned by Contractor to overcome the effect of the delay or potential delay.

5.3.2 Without limiting the obligations of Contractor under Section 5.3.1, above, Contractor shall provide, together with its monthly status reports required hereunder, a project schedule and any updates thereto that provide for the orderly, practicable and expeditious completion of the Work in accordance with the requirements of the Contract Documents. The project schedule and any update shall be presented

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electronically on a monthly basis and in such reasonable detail as FPL and the Independent Engineer may require and shall address all material elements of the Work. Additionally, the updated project schedule shall be made available to FPL monthly, and as otherwise reasonably requested by FPL, in MS Project format on a computer located at the Property Site. Contractor shall consult with FPL in connection with each update provided under this paragraph. Notwithstanding anything contained herein to the contrary, in the absence of a Change Order, no update to the project schedule shall in any way amend, alter or otherwise change the Project Schedule or the Guaranteed Provisional Acceptance Date.

5.3.3 *Adequate Assurance.* In the event FPL reasonably believes Contractor's completion of any Critical Milestone set forth in Appendix C, Critical Milestones and Milestones, will not be completed by the date required therein, FPL shall notify Contractor in writing, and Contractor shall, within seven (7) days of receipt of FPL's notice, provide to FPL a written plan detailing the activities or sequence of events Contractor will implement to assure completion of the Critical Milestone by the date required in Appendix C, Critical Milestones and Milestones, and Contractor shall promptly implement such activities and sequence of events. In the event Contractor fails to complete any of the Critical Milestones by the date required in Appendix C, Critical Milestones and Milestones, Contractor shall provide to FPL a written recovery plan that will demonstrate achievement of the Critical Milestone at the earliest possible date to minimize delay of the Project Schedule and Contractor shall promptly implement any such recovery plan. Such recovery plan shall include, without limitation, reasonable evidence of increases in Contractor's work force, increases in the number of shifts, overtime operations, additional days of Work per week, and such other evidence (including Critical Path schedule analysis) as necessary for the timely completion of the Work in accordance with the Contract Documents. Approval by FPL and the Independent Engineer of such plan shall not:

(a) Be deemed in any way to have relieved Contractor of its obligations under this Agreement relating to the failure to achieve Mechanical Completion or Provisional Acceptance by the Guaranteed Provisional Acceptance Date;

(b) Be a basis for an increase in the Contract Price; or

(c) Limit the rights of FPL under Section 11.2, SCHEDULE LIQUIDATED DAMAGES, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

Further, Contractor acknowledges that the implementation of any such recovery plan may result in material additional costs and expenditures for Contractor (including by way of overtime, additional crews and/or additional shifts). Contractor agrees that it shall not be entitled to a Change Order or any other compensation or increase in the Contract Price in connection with the implementation of any such recovery plan.

5.3.4 No later than fifteen (15) days following the date hereof, Contractor shall prepare and submit to FPL for review and comment a preliminary draft of the Critical Path, in form and content acceptable to FPL. Upon receipt of comment from FPL, Contractor shall either promptly make changes to the Critical Path as suggested by FPL or negotiate and resolve in good faith with FPL such changes. Upon approval of the Critical Path by the Parties, Contractor shall comply with the provisions thereof. Contractor shall provide five (5) copies, as well as an electronic copy, of the Critical Path to FPL. Contractor shall not revise or modify the Critical Path, except pursuant to a Scope Change Order mutually agreed by the Parties.

5.3.5 In no event will Contractor's failure to complete one or more Milestones by the date required for such Milestone change, delay or otherwise affect the required completion date for any other Milestone.

5.4 ACCELERATION OF WORK

In addition to the provisions of Sections 5.3.3, above, relating to delays in the Work, in the event of delay, including any event which causes the prosecution of the Work to fail to conform to the Project Schedule, FPL may, by notice to Contractor, direct that the Work be accelerated by means of overtime, additional crews or additional shifts or resequencing of the Work. If:

(a) Such delay arises from any FPL Caused Delay or Force Majeure Event; or

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(b) Contractor provides reasonable evidence to FPL that such delay results from a suspension pursuant to Section 15.4, SUSPENSION BY FPL FOR CONVENIENCE, of Article XV, TERMINATION.

then Contractor shall be entitled to reimbursement of increased cost as a result of such acceleration (i.e., premium portion of overtime pay, additional crew, shift or Equipment cost and such other items of incremental cost requested in advance by Contractor and approved by FPL which approval will not be unreasonably withheld) less savings or costs not incurred due to such acceleration, but expressly waives any other compensation therefor. CONTRACTOR SHALL RECEIVE NO SUCH REIMBURSEMENT FOR COSTS ARISING OUT OF, AND CONTRACTOR SHALL BE SOLELY RESPONSIBLE FOR ANY COSTS INCURRED BY CONTRACTOR AS A RESULT OF, ACCELERATION RELATED TO ANY EVENT OTHER THAN THE EVENTS SPECIFICALLY DESCRIBED IN THIS SECTION 5.4, PARAGRAPHS (a) AND (b), ABOVE. Contractor shall cause prosecution of the Work to conform to the Project Schedule within thirty (30) days after receiving written notice from FPL to accelerate the Work.

5.5 LIQUIDATED DAMAGES

Nothing contained in this Article shall relieve Contractor of its obligation to pay Schedule Liquidated Damages in the event that Provisional Acceptance is not achieved by the Guaranteed Provisional Acceptance Date.

ARTICLE VI.
CHANGE ORDERS

6.1 CHANGE ORDER AT FPL'S REQUEST.

6.1.1 FPL may at any time, by written notice to Contractor, request an addition to or deletion from or other changes in the Work or schedule therefor (together with any necessary or requested amendments to this Agreement with respect thereto) (hereinafter "Change" or "Changes") by submitting a Request for Change Order in the form attached hereto as Appendix S, Form of Request for Change Order. Contractor shall review and consider such requested Change and shall make a written response thereto within ten (10) days after receiving such request. If Contractor believes that giving effect to any Change requested by FPL will increase or decrease its cost of performing the Work, shorten or lengthen the time needed for completion of the Work, require modification of its warranties in Article XII, CONTRACTOR'S WARRANTIES, or require a modification of any other provisions of the Contract Documents, its response to the Change request shall set forth such changes (including any amendments to the Contract Documents) that Contractor deems necessary as a result of the requested Change and its justification therefor. If Contractor accepts the Changes requested by FPL (together with any amendments to the Contract Documents specified therein) or if the Parties agree upon a modification of such requested Changes, the Parties shall set forth the agreed upon Change in the Work and agreed upon amendments to the Contract Documents, if any, in a written change order signed by all Parties (a "Change Order"). Each Change Order shall constitute a final settlement of all items covered therein, including any compensation for impact on, or delay or acceleration in, performing the Work. If the Parties do not agree upon all terms of the Change Order, Contractor shall proceed with such Work and the dispute shall be resolved in accordance with Article XVII, DISPUTE RESOLUTION; provided that if the Parties are unable to reach agreement on the cost of a requested Change, Contractor shall perform the requested Change in accordance with Section 6.3, CHANGES TO CONTRACT PRICE, below.

6.1.2 FPL may at any time, by written notice to Contractor, propose Changes in the Work or the Project Schedule due to a Force Majeure Event or an FPL Caused Delay. If there is a material impact that will actually, demonstrably, adversely and materially affect Contractor's ability to complete one or more Critical Milestones by the required date as a result of such Force Majeure Event or an FPL Caused Delay, then the Parties agree to bargain reasonably and in good-faith for the execution of a mutually acceptable Change Order. Force Majeure Events will only entitle Contractor to extensions of the Project Schedule.

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6.2 CHANGE ORDERS REQUESTED BY CONTRACTOR.

6.2.1 It is the intent of FPL and Contractor that the Scope of Work attached hereto as Appendix A, Scope of Work, includes all items necessary for the proper execution and completion of the Work. As more particularly described in Section 3.1.3, Contractor's Exclusions, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR work not described in the Scope of Work attached hereto as Appendix A, Scope of Work, shall not require a Change Order if such work is consistent with and reasonably inferable from the Scope of Work, so that an engineering, procurement and construction contractor of Contractor's experience and expertise should have anticipated that the work would have been required.

6.2.2 Subject to Section 6.2.3, below, Contractor may at any time, by written notice to FPL, request a Change in the Work (together with any necessary or requested amendments to the Contract Documents) and FPL may accept or reject such request in its sole discretion. If Contractor believes that such requested Change will increase or decrease its cost of performing the Work, lengthen or shorten the time needed for completion of the Work, require modification of its warranties in Article XII, CONTRACTOR'S WARRANTIES, or require a modification of any other provisions of the Contract Documents, it shall notify FPL of such, setting forth its justification for and effect of such changes, within ten (10) days after making a request for a Change. If FPL accepts the Changes requested by Contractor (together with amendments to the Contract Documents specified therein, if any), or if the Parties agree upon a modification of such requested Changes, the Parties shall set forth the agreed upon Change in the Work and agreed upon amendments to the Contract Documents, if any, in a written Change Order signed by all Parties. For the avoidance of doubt, the Parties agree that FPL's representative referred to in Section 4.11 shall not have authority to approve Change Orders. The Parties acknowledge and agree that one or more of the documents and agreements, including agreements with Subcontractors, may not be amended orally or through course of conduct. The Parties hereby express their intention that this Agreement will not be modified orally, through course of conduct or otherwise (regardless of whether any other agreements or documents relating to this Project have been so amended or modified).

6.2.3 Contractor may at any time, by written notice to FPL, propose Changes in the Work or the Critical Milestones due to:

(a) A Force Majeure Event, provided that such Force Majeure Event has an impact that will actually, demonstrably, adversely and materially affect Contractor's ability to complete one or more Critical Milestones by the required dates and further provided that Contractor complies with requirements provided in Article XIV, FORCE MAJEURE EVENT AND FPL CAUSED DELAY, and Section 6.2.2, above;

(b) An FPL Caused Delay, provided that such FPL Caused Delay has a demonstrable material cost increase to Contractor and/or schedule impact that will actually, demonstrably, adversely and materially affect Contractor's ability to complete one or more Critical Milestones by the required dates and further provided that Contractor complies with the requirements set forth in Article XIV, FORCE MAJEURE EVENT AND FPL CAUSED DELAY;

(c) A Change In Law, provided that such Change In Law prevents Contractor from performing all or a portion of the Work, has a demonstrable material cost increase to Contractor and/or has a schedule impact that will actually, demonstrably, adversely and materially affect Contractor's ability to complete one or more Critical Milestones by the required dates, and further provided that Contractor shall diligently make adjustments to minimize the effect of such Change In Law on the Project; or

(d) Certain unforeseeable subsurface conditions but only to the extent provided in Section 3.4.4, Differing Condition, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

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Unless the foregoing conditions are met, Contractor may not request a Change in the Work or Critical Milestones due to a Force Majeure Event, FPL Caused Delay, Change In Law or unforeseeable subsurface conditions.

6.2.4 If FPL agrees that Contractor has met all of the applicable conditions precedent for a requested Change, then the Parties agree to bargain reasonably and in good faith for the execution of a mutually acceptable Change Order. Force Majeure Events will only entitle Contractor to extensions of the Project Schedule. If in such event the Parties are unable to agree on a mutually acceptable Change Order, then the dispute shall be resolved in accordance with Article XVII, DISPUTE RESOLUTION. Any extension permitted under this Section shall be of an equitable duration designed to reflect the delay actually caused by the relevant event despite Contractor's reasonable efforts to mitigate the same.

6.2.5 Intentionally Deleted.

6.2.6 If Contractor knows of circumstances or events that do or may require a Change in the Work or Project Schedule, and Contractor does not provide written notification to FPL of such within fifteen (15) days after the date Contractor knows or should have known (in the exercise of due diligence) of such circumstances or events, then Contractor shall not have any right to request or require any additional consideration or other changes as to cost, schedule, warranty obligations or other provisions hereof, and Contractor shall have waived any claims or offsets against FPL, with respect to any Change Order or any necessary Change in the Work or Project Schedule arising out of such circumstances or events.

6.3 CHANGES TO CONTRACT PRICE; DISPUTES

A Change Order initiated by either Party may have the effect of either increasing or decreasing the Contract Price. Any Contractor response to a Change Order under Section 6.1, CHANGE ORDER AT FPL'S REQUEST, above, and any Contractor request for Changes under Section 6.2, CHANGE ORDERS REQUESTED BY CONTRACTOR, above, shall be accompanied by a proposed all inclusive final lump sum cost (separating materials and labor) to FPL. In the event that the Parties are unable to reach an agreement on an all-inclusive final lump sum cost to FPL or a not-to-exceed cost as a result of a requested Change, then Contractor agrees to perform the requested Change and the Contract Price shall be adjusted by the amount of such additional cost and expense as is not in dispute pending resolution of the dispute pursuant to Article XVII, DISPUTE RESOLUTION. In addition, in the event that FPL and Contractor are unable to reach agreement on a Change Order for a Change requested by either FPL or Contractor, at the direction of FPL (and only at the direction of FPL), FPL's proposed Changes shall become effective as a Change Order and Contractor shall continue to perform the Work in accordance with such Change Order and the proposed Changes shall be performed by Contractor at its sole cost and expense pending resolution of the dispute pursuant to Article XVII, DISPUTE RESOLUTION.

6.4 INFORMATION REQUESTS

FPL may request that Contractor provide written information (prior to the issuance of a request for Changes) regarding the effect of a contemplated Change on pricing, scheduling, warranty obligations or on other terms of the Contract Documents. The purpose of such a request will be to determine whether or not a Change will be implemented. Contractor shall provide the requested information within fourteen (14) days after the receipt of said request. Contractor will be allowed to reasonably delay its response to such request to the extent that fulfilling such request would significantly delay progress on the Work, unless FPL agrees to extend the required completion date for the affected Milestone. Such an information request is not a Change Order and does not authorize Contractor to commence performance of the contemplated change in Scope of Work.

6.5 MINOR CHANGES

FPL shall have the direct authority to issue clarifications and order minor changes in the Work, effected by written order, which do not involve any adjustment to the Contract Price or the Guaranteed Provisional Acceptance Date and do not require Contractor to incur any additional material cost or expense; provided that such clarifications and changes are consistent with the intent of the Contract Documents. Such clarifications and changes shall be binding on FPL and Contractor. Contractor shall carry out such written

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(a) Schedule Liquidated Damages payable by Contractor;

(b) Amounts withheld pursuant to:

(i) Section 7.3.3, Protect FPL From Loss;

(ii) Section 7.6.1, Satisfaction of Liens, below; and

(c) Reasonable costs incurred by FPL in enforcing:

(i) Section 6.2.2, of Article VI, CHANGE ORDERS;

(ii) Section 14.5, NOTICE OF FPL CAUSED DELAY, of Article XIV, FORCE MAJEURE AND FPL CAUSED DELAY; or

(iii) Any other provision hereof (including attorneys' and other consultants' fees) regardless of whether such provisions expressly provide for withholding or set-off.

7.3 GENERAL PROVISIONS FOR PAYMENTS.

7.3.1 If applicable, any payment by FPL shall be accompanied by a notice to Contractor specifying the amount of each deduction and setting forth the reason(s) why the deduction is justified; provided that FPL's failure to provide any such notice shall not result in a breach hereof or be deemed a waiver of any right to deduct any amount hereunder. NOTWITHSTANDING ANY PROVISION OF THIS AGREEMENT TO THE CONTRARY, FAILURE BY FPL TO PAY ANY AMOUNT DISPUTED IN GOOD FAITH UNTIL RESOLUTION OF SUCH DISPUTE IN ACCORDANCE WITH THIS AGREEMENT SHALL NOT ALLEVIATE, DIMINISH, OR MODIFY IN ANY RESPECT CONTRACTOR'S OBLIGATIONS TO PERFORM HEREUNDER, INCLUDING CONTRACTOR'S OBLIGATION TO MEET THE GUARANTEED PROVISIONAL ACCEPTANCE DATE.

7.3.2 Failure or forbearance on the part of FPL in withholding any amounts due under a Request for Payment or invoice shall not be construed as accepting or acquiescing to any disputed claims. In addition, the making of any payment by FPL shall not constitute an admission by it that the Work covered by such payment (or any Work previously performed) is satisfactory or timely performed, and FPL shall have the same right to challenge the satisfactoriness and timeliness of such Work as if it had not made such payment. If, after any such payment has been made, it is subsequently determined by FPL, acting reasonably, that Contractor was not entitled to all or a portion of any such payment, Contractor shall promptly refund all or a portion of such payment to FPL.

7.3.3 *Protect FPL From Loss*. Notwithstanding any other provision to the contrary contained herein, FPL, in addition to its rights set forth in Section 7.5, LETTERS OF CREDIT, shall have no obligation to make payments to Contractor hereunder and FPL may decide not to certify payment or may nullify the whole or a part of a certification for payment made pursuant to a previous Request for Payment to such extent as may be necessary in FPL's opinion to protect FPL from loss because of:

(a) Defective Work not remedied;

(b) Third party claims filed (including Liens), or reasonable evidence indicating probable filing of such claims;

(c) Failure of Contractor to make payments when due to Subcontractors or Vendors;

(d) Damage to FPL or another contractor, including damage to the property of FPL or any of its Affiliates but only to the extent Contractor may be liable for such damage pursuant to this Agreement;

(e) Contractor's, or any Subcontractor's or Vendor's failure to carry out the Scope of Work in accordance with the Contract Documents;

(f) The occurrence of a Contractor Event of Default;

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(g) A good faith determination by FPL that Contractor cannot, with prompt and reasonable acceleration of the Work, achieve Provisional Acceptance before the Guaranteed Provisional Acceptance Date; provided, however, the amount withheld or retained on account of this paragraph, shall not exceed the amount of Schedule Liquidated Damages which would be payable under Section 11.2, SCHEDULE LIQUIDATED DAMAGES, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, on account of the then estimated delay in Provisional Acceptance;

(h) Contractor's failure to deliver a recovery plan acceptable to FPL as set forth in:

(i) Section 5.3.3, Adequate Assurance, of Article V, PROJECT SCHEDULE, or

(ii) the failure of Contractor to cause the prosecution of the Work to conform to any such recovery plan accepted by FPL;

(i) Contractor's failure to deliver any Contractor Deliverable to FPL on or before the date such item is scheduled to be delivered; or

(j) Contractor's failure to remove and replace, or cause any Subcontractor or Vendor to remove and replace, within ten (10) days after receiving notice pursuant to Section 3.11.11, Replacement at FPL's Request, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, any employee of Contractor or such Subcontractor or Vendor who is employed in the Work or the warranty obligations of Contractor or such Subcontractor or Vendor.

Notwithstanding the provisions of Section 15.7, TERMINATION BY CONTRACTOR DUE TO FPL DEFAULT, of Article XV, TERMINATION, and 17.3, CONTINUING OBLIGATIONS AND RIGHTS, of Article XVII, DISPUTE RESOLUTION, Contractor shall not have any rights of termination or suspension under such Sections as a result of FPL's exercise or attempted exercise of its rights under this Section 7.3. FPL shall release payments withheld pursuant to this Section 7.3.3 within thirty (30) days from the date when Contractor cures all such breaches to the satisfaction of FPL.

7.3.4 Each payment made pursuant to this Article shall be paid directly to Contractor. Such payment shall be wire-transferred to an account or accounts designated by Contractor in its Request for Payment.

7.4 INTENTIONALLY DELETED.

7.5 LETTERS OF CREDIT

Simultaneously with the execution of this Agreement, Contractor shall, at its own expense, cause the LC Issuing Bank to issue and maintain, by renewal or replacement, for the periods specified herein, an irrevocable, unconditional, transferable, standby, revolving letter of credit in favor of FPL meeting the requirements of this Section 7.5, and in form and substance as set forth on Appendix U, Form of Letter of Credit, (the "Letter of Credit") and such Letter of Credit must provide for draws in the United States. The Letter of Credit shall constitute security for Contractor's obligations hereunder. All fees and charges, including, without limitation, issuing, commitment and operation fees and charges, relating to the Letter of Credit shall be borne by Contractor. The Letter of Credit shall comply with and be subject to the following terms and conditions:

7.5.1 Upon issuance, the Letter of Credit shall have a face amount equal to Six Million Nine Hundred Thousand and 00/100 Dollars ($6,900,000.00). On the date (the "Initial LC Amount Expiration Date") sixty (60) days after either Contractor satisfies the Energy Yield Test or the Contract Price is reduced, in each case, in accordance with Section 11.4.3,, and thereafter so long as the Letter of Credit is required to be provided hereunder, the face amount shall automatically be reduced to (or the LC Issuing Bank may issue a replacement Letter of Credit with a face amount equal to) Three Million Four Hundred and Fifty Thousand and 00/100 Dollars ($3,450,000.00); provided, if Contractor elects to cause the LC Issuing Bank to issue a replacement Letter of Credit to FPL, upon receipt of such replacement Letter of Credit by FPL, FPL shall, as promptly as practicable thereafter, mark the replaced Letter of Credit "canceled" and return it to the LC Issuing Bank for cancellation. Within seven (7) Days of FPL's notice to Contractor of the occurrence of a Credit Trigger Event, either (a) the face amount of the Letter of Credit shall be adjusted in accordance with

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person relating to or affecting this Agreement, except claims for which Contractor has delivered a dispute notice to FPL. No payment by FPL shall be deemed a waiver by FPL of any obligation of Contractor under this Agreement.

ARTICLE VIII.
TITLE, RISK OF LOSS AND POSSESSION

8.1 CLEAR TITLE

8.1.1 Contractor warrants and guarantees that legal title to and the ownership of the Work (including, without limitation, all Equipment, patents, licenses, Contractor Deliverables, operation and maintenance manuals and any spare parts purchased by Contractor on behalf of FPL at FPL's request in connection with the construction, operation and maintenance of the Plant) shall pass to FPL, free and clear of any and all Liens, upon Provisional Acceptance.

8.1.2 Notwithstanding anything to the contrary, the costs of unloading and transporting to the Job Site are included in the Contract Price.

8.2 RISK OF LOSS

8.2.1 From the date hereof until the Provisional Acceptance Date, Contractor hereby assumes the risk of loss for the Project and the Work, including:

(a) Any Equipment whether on or off the Job Site;

(b) All other Work completed on or off the Job Site; and

(c) All Work in progress.

8.2.2 All Equipment not yet incorporated into the Plant shall be stored in secured areas. Contractor shall bear the responsibility of preserving, safeguarding, and maintaining such Equipment and any other completed Work and Work in progress (including spare parts provided by FPL). If any loss, damage, theft or destruction occurs to the Work, on or off the Job Site, for which Contractor has so assumed the risk of loss, Contractor shall, at FPL's option and at Contractor's cost, promptly repair or replace the property affected thereby. If FPL elects not to repair or replace the affected property, Contractor shall pay to FPL any proceeds received from the insurance required to be maintained by Contractor pursuant to Section 9.1.8 or 9.1.9 due to such loss, damage, theft or destruction. Risk of loss for the Project and the Work shall pass to FPL (excluding Contractor Equipment and other items to be removed by Contractor, which shall remain the responsibility of Contractor) on the Provisional Acceptance Date. Subject to the foregoing, from and after the date of the transfer of risk of loss, FPL shall assume all risk of physical loss or damage thereto; provided, however, Contractor shall, subject to the provisions of Article XII, Contractor's Warranties, continue to be responsible after Provisional Acceptance Date for claims, physical loss or damage to the Work to the extent resulting from (a) the acts or omissions of Contractor or any Affiliate thereof, any Subcontractor or Vendor, or anyone directly or indirectly employed by any of them, or anyone for whose acts such Person may be liable and/or (b) any failure to comply with the requirements of the Contract Documents.

ARTICLE IX.
INSURANCE

9.1 CONTRACTOR INSURANCE POLICIES

Upon execution of the Agreement and continuing through the Final Acceptance Date, Contractor shall, at its sole cost and expense, obtain and maintain and cause its Subcontractors to obtain and maintain in force insurance policies satisfying the requirements of this Article, providing the following coverages of the types and in the amounts as follows (the "Contractor Insurance Policies"):

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9.1.1 *Workers' Compensation Insurance*. Workers' Compensation that complies with the laws of the State of Florida and such other jurisdictions as may be applicable to its operations and includes an alternate employer endorsement. The amount of coverage of the insurance policy shall be the statutory amount required by the laws of the State of Florida. Where applicable, coverage shall include protection under the U.S. Longshoreman's and Harbor Worker's Act, Outer Continental Shelf Lands Act and Maritime Law, including the Jones Act and Death on the High Seas Act. Contractor expressly agrees to comply with all provisions of the Workers' Compensation Laws or similar employee benefit laws of the United States, or wherein said Work is to be performed, or of the countries from which its personnel are employed, where required, if applicable.

9.1.2 *Employers' Liability Insurance*. Employers' Liability Insurance including Occupational Disease in the amount of One Million Dollars ($1,000,000).

9.1.3 *Comprehensive or Commercial General Liability Insurance*. Comprehensive or Commercial General Liability insurance shall be on a broad form occurrence basis which shall be in the amount of One Million Dollars ($1,000,000) per occurrence and Two Million Dollars ($2,000,000) in the aggregate for this Project including, but not limited to coverage for the following:

(a) Premises and Construction Operations;

(b) Independent Contractors;

(c) Products and Completed Operations, maintained for a period of two (2) years from the Final Acceptance Date;

(d) Explosion, Collapse and Underground Hazards;

(e) Broad Form Contractual Liability Coverage, applicable to damages and indemnities set forth in this Agreement;

(f) Personal Injury Coverage;

(g) Non-Owned Watercraft, if applicable;

(h) Broad Form Property Damage;

(i) Cross Liability coverage or Severability of Interest clause;

(j) Broad Form Named Insured Endorsement; and

(k) Action over coverage.

9.1.4 *Automobile Liability Insurance*. Automobile Liability Insurance, on an occurrence basis including coverage for all owned, leased, hired or non-owned automotive equipment (and containing appropriate no fault insurance provisions or other endorsements as are required under jurisdictional law or requirements), in the amount of One Million Dollars ($1,000,000) per occurrence or the amount required by Applicable Law, whichever is greater.

9.1.5 *Umbrella Excess Liability Insurance*. Umbrella Excess Liability to be provided on a following form basis with coverage as broad as the primary policies in the amount of Twenty Million Dollars ($20,000,000) each occurrence and in the aggregate.

9.1.6 *All Risk Equipment Insurance*. All Risk Equipment Insurance covering all risk of physical damage to equipment owned by Contractor and/or provided for use at the Job Site by Contractor.

9.1.7 *Professional Liability Insurance*. Professional Liability Insurance on a claims made basis with limits of $1,000,000 each occurrence and, at execution of this Agreement, $2,000,000, and upon the Commencement Date, $3,000,000, aggregate for liability arising out of any negligent act, error, mistake or omission resulting from Contractor's engineering, procurement, construction, design, commissioning, start-up and testing services, such coverage to remain in effect for not less than four (4) years following Provisional Acceptance.

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9.1.8 *Inland and Marine Cargo Insurance.* Inland and Marine Cargo Insurance, if applicable - replacement value, which coverage may be included as part of the Builder's Risk Policy.

9.2 FORM OF CONTRACTOR INSURANCE POLICIES.

9.2.1 Each Contractor Insurance Policy shall be written on an occurrence basis. Subject to the limits and coverages specified in Section 9.1, CONTRACTOR INSURANCE POLICIES, and except for Workers' Compensation, Contractor shall name FPL, designated Affiliates of FPL, the Utility, the Financing Parties and any other Person designated by FPL (including their respective officers, directors and employees) as additional insureds on Contractor's liability policies as required to be carried by Contractor by the provisions of Section 9.1, CONTRACTOR INSURANCE POLICIES, for liabilities of Contractor under the Contract Documents. Each Contractor Insurance Policy shall provide, either in its printed text or by endorsement, that:

(a) It shall be primary with respect to the interest of FPL, designated Affiliates of FPL and the Financing Parties (including their respective officers, directors and employees); and

(b) Any other insurance maintained by FPL, designated Affiliates of FPL or the Financing Parties is in excess and not contributory to Contractor Insurance Policies in all instances regardless of any like insurance coverage that FPL, designated Affiliates of FPL and the Financing Parties may have.

9.2.2 Contractor shall require the issuers of the coverages specified in 9.1, CONTRACTOR INSURANCE POLICIES, to amend such Contractor Insurance Policies to:

(a) Include a waiver of all rights of subrogation against the Financing Parties, FPL and designated Affiliates of FPL and any other Person designated by FPL and their respective directors, officers and employees;

(b) Contain a severability of interest provision;

(c) Provide that none of the Financing Parties, FPL or designated Affiliates of FPL or their respective directors, officers or employees shall be liable for the payment of premiums under such policy;

(d) Provide that complete copies of all inspection or other reports required or performed for the insurer shall be provided to both FPL and the Financing Parties within thirty (30) days of delivery to Contractor;

(e) Provide that FPL and the Financing Parties must be given at least sixty (60) days' prior written notice of any change in, non-renewal or cancellation of such coverages that are initiated by insurer, except ten (10) days for non-payment of premium, and

(f) Provide that FPL and the Financing Parties must be given at least sixty (60) days' prior written notice of any change in, non-renewal or cancellation of such coverages that are initiated by Contractor, except ten (10) days for non-payment of premium.

9.2.3 Contractor shall be responsible for additional costs associated with modifying inadequate coverage, terms and conditions to meet the requirements of this Agreement. Contractor shall comply with all the conditions stipulated in each of the insurance policies. Contractor shall make no material alteration to the terms of any insurance required herein without the prior written approval of FPL. If an insurer makes (or purports to make) any such alteration, Contractor shall notify FPL immediately. If any such notice is sent from an office outside the United States, it will be sent by international courier. Contractor shall be responsible to insure against risk of loss or damage to any Contractor Equipment and other equipment and tools that will not be incorporated into or become part of the Project.

9.3 QUALIFIED INSURERS

All Contractor Insurance Policies shall be written by insurers reasonably acceptable to FPL and the Financing Parties and that are rated "A-" or higher by A.M. Best's Key Rating Guide, or as may be approved in writing

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by FPL and the Financing Parties from time to time (a "Qualified Insurer"). In addition, if required by the Financing Parties, the Qualified Insurer must be able to provide a non-vitiation endorsement.

9.4 CERTIFICATES OF INSURANCE

Contractor shall require all insurers under Contractor Insurance Policies to provide the Financing Parties, FPL and such other interested Persons as may be designated by FPL with certificates of insurance, in form and substance acceptable to the Financing Parties and FPL, evidencing and describing the insurance policies and endorsements maintained hereunder prior to commencement of the Work, or upon issuance of such policies, if earlier, and on each issuance anniversary while such insurance is in effect. The certificates of insurance shall evidence and describe the insurance policies and endorsements, including, without limitation, the requirements for the additional insured and waiver of subrogation as described in Section 9.2, FORM OF CONTRACTOR INSURANCE POLICIES. Notwithstanding anything to the contrary contained herein, evidence of such coverage shall be provided to FPL as a condition precedent to Initial Site Mobilization.

9.5 INSPECTION OF CONTRACTOR INSURANCE POLICIES

In respect of all Contractor Insurance Policies, Contractor shall, when so requested by FPL, produce Contractor's policies of insurance and confirmation of premium payment for such policies. If policies have not been secured on a project specific basis, Contractor may delete proprietary information not relevant to Contractor/FPL project prior to transmission.

9.6 SUBCONTRACTORS' INSURANCE

Before permitting any of its Subcontractors to perform any Work at the Job Site, Contractor shall obtain a certificate of insurance from each such Subcontractor evidencing that such Subcontractor has obtained the insurance required of Subcontractors by Contractor and in the case of Substantial Subcontractors, as required by FPL. All policies of Substantial Subcontractors shall include, and Contractor shall use reasonable efforts to require all other Subcontractors to include, a waiver of any right of subrogation of the insurers thereunder against FPL, the Financing Parties and Contractor, and any right of the insurers to set-off or counterclaim, offset or any other deduction, whether by attachment or otherwise, in respect of any liability or any such Person insured under such policy. Policies provided by Substantial Subcontractors and Substantial Vendors shall be in amounts and upon conditions as are customarily and normally provided in the major, grid-connected solar power generation industry.

9.7 REMEDY ON FAILURE TO INSURE

If Contractor shall fail to obtain and keep in force Contractor Insurance Policies, FPL may, without limiting any other remedy it may have, obtain and keep in force any such insurance and pay such premium or premiums as may be necessary for that purpose and recover from Contractor whether by way of deduction, offset or otherwise the cost of obtaining and maintaining such insurance.

9.8 MANAGEMENT OF INSURANCE POLICIES

Except as directed by FPL, Contractor shall be responsible for managing and administering all Contractor Insurance Policies, including the payment of all deductibles and self-insured retention amounts, the filing of all claims and the taking of all necessary and proper steps to collect any proceeds on behalf of the relevant insured Person. Contractor shall at all times keep FPL informed of the filing and progress of any claim. If Contractor shall fail to perform these responsibilities, FPL may take such action as it determines appropriate under the circumstances. In the event Contractor collects proceeds on behalf of other Persons, it shall ensure that these are paid directly from the insurers to the relevant Person and, in the event that it receives any such proceeds, it shall, unless otherwise directed by FPL, pay such proceed to such Party forthwith and prior thereto, hold the same in trust for the recipient.

9.9 FPL INSURANCE POLICIES

Subject to Section 9.9.3, prior to the Initial Site Mobilization by Contractor and continuing through the Final Acceptance Date, FPL shall obtain and maintain in force with responsible and reputable insurance carriers, subject to usual and customary terms, exclusions and limitations and deductible provisions the following insurance of the types set forth below:

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9.9.1 *Workers' Compensation Insurance*. Workers' Compensation covering all of FPL's employees - statutory limit;

9.9.2 *Employers' Liability Insurance*. Employers' Liability covering all of FPL's employees;

9.9.3 *Property Insurance*. After Provisional Acceptance and through the end of all of the Warranty Periods, FPL shall provide property insurance for the Plant and the Property Site in an amount and on terms that FPL deems reasonable.

9.9.4 *All Risk Installation and Builder's Risk Insurance*. No later than the Commencement Date, FPL shall obtain and maintain in force an All Risk Installation and Builder's Risk Insurance Policy (the "Builder's Risk Policy"). The Builder's Risk Policy shall be in an amount at least equal to the maximum foreseeable loss that could reasonably be sustained with respect to the Project or, if such amount is unavailable, such lower amount as may be commercially available at the time FPL procures such policy. A certificate of insurance evidencing the Builder's Risk Policy shall be furnished to the Contractor within thirty days after Contractor notifies FPL in writing that it will construct improvements at, or deliver materials to, the Job Site that may be insured pursuant to a builder's risk policy. Contractor shall be named as an additional insured on any Project-specific Builder's Risk Policy. The Builder's Risk Policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines, provided the per occurrence deductible shall not exceed the amounts which are available to FPL on a commercially reasonable basis, as determined by FPL in its sole discretion. The Builder's Risk Policy will be maintained in accordance with terms reasonably available in the insurance market for the construction of major solar electric generating facilities and shall cover physical loss to property at the Job Site which results from a Defect but will not cover the Defect, including the cost to remedy the Defect. FPL shall cause the underwriter of the Builder's Risk Policy to waive all rights of subrogation against Contractor and its Subcontractors for damages covered by the Builder's Risk Policy. If a loss is insured under the Builder's Risk Policy, FPL will prepare and submit to the insurer any claim and proof of loss in accordance with the terms of the Builder's Risk Policy, and Contractor shall provide FPL with such documentation as FPL may reasonably require in connection with the preparation of such claim and proof of loss. FPL shall use commercially reasonable efforts for the benefit of the Parties in pursuing any claim under the Builder's Risk Policy, including, if permitted by the Builder's Risk Policy, pursuit of partial payment for partial proof of loss and payment of undisputed amounts due under the Builder's Risk Policy, provided Contractor acknowledges and agrees that the Builder's Risk Policy may not require such partial payments. FPL shall keep the Contractor reasonably informed of the status of claims negotiations between FPL and the insurer under the Builder's Risk Policy and if Contractor is not satisfied with the progress of such negotiations, it shall have the right to address such dissatisfaction with FPL's management and FPL shall use reasonable efforts to address Contractor's concerns. Notwithstanding the foregoing and subject to FPL's obligation to use commercially reasonable efforts in pursuing claims under the Builder's Risk Policy, any decisions made in the settlement or negotiation of any claim under the Builder's Risk Policy shall be in FPL's sole discretion. Upon availability and reasonable prior notice, Contractor's authorized representative shall be entitled to receive a copy of the Builder's Risk Policy. Contractor is responsible for the deductible under the Builder's Risk Policy; provided, however, Contractor's responsibility therefor shall in no event exceed $500,000 per occurrence.

9.10 FORM OF FPL'S POLICIES

9.10.1 FPL shall provide Contractor with a certificate of insurance evidencing those policies set forth in Section 9.9, FPL INSURANCE POLICIES. As it applies to this Agreement, FPL shall provide that the insurance required pursuant to Section 9.9, FPL INSURANCE POLICIES, shall, except for Workers' Compensation, name Contractor and its Subcontractors as additional insureds thereunder only as their respective interests may appear but only with respect to Work performed pursuant to the Agreement.

9.10.2 Contractor shall be responsible for the payment of all deductibles for such claims caused, directly or indirectly, through the acts or omissions of Contractor, any Affiliate thereof, any Subcontractor or Vendor, or anyone directly or indirectly employed by any of them, or anyone for whose acts such Person may be liable.

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9.11 CONTRACTOR'S ASSISTANCE

In the event a loss is sustained under any of FPL's policies, such loss will be adjusted by FPL and/or the Financing Parties with the insurance companies. Contractor will assist FPL and the Financing Parties in the adjustment of losses. In the event a loss is sustained under the Builder's Risk Policy, such loss will be adjusted by Contractor and FPL with the insurance companies. FPL and Contractor agree to waive all rights of recovery against each other, and shall cause their respective underwriters to waive all rights of subrogation, for damages caused by fire and/or other perils to the extent covered and paid for by the Cargo Insurance. Contractor shall cooperate with FPL in obtaining and maintaining the insurance policies of FPL and shall provide all Drawings, Final Plans, certificates and other information that FPL or its insurers may reasonably require. Upon FPL's reasonable request, Contractor shall with all due diligence comply with the conditions of FPL's insurance polices and all reasonable requirements of the insurers in connection with the settlement of claims, the recovery of losses and the prevention of accidents and shall bear at its own cost the consequences of any failure to do so.

9.12 RESPONSIBILITY FOR SAFE DELIVERY OF MATERIALS OF CONTRACTOR

In addition to Section 8.2., RISK OF LOSS, of Article VIII, RISK OF LOSS AND POSSESSION, Contractor shall comply with all warranty requirements or other requirements set forth in all policies, including transport or marine/inland marine cargo insurance policies.

9.13 NO LIMITATION ON LIABILITY

Nothing in this Article shall be deemed to limit Contractor's liability under the Contract Documents regardless of the insurance coverages required by this Article. Except for the coverage limits of liability for insurance companies set forth in Section 9.1, CONTRACTOR INSURANCE POLICIES, no limitation of liability provided to Contractor under the Contract Documents is intended nor shall run to the benefit of any insurance company or in any way prejudice, alter, diminish, abridge or reduce, in any respect, the amount of proceeds of insurance otherwise payable to FPL or the Financing Parties under coverage required to be carried by Contractor under the Contract Documents, it being the intent of the Parties that the full amount of insurance coverage bargained for be actually available notwithstanding any limitation of liability contained in the Contract Documents, if any. FPL assumes no responsibility for the solvency of any insurer or the failure of any insurer to settle any claim.

9.14 FPL CONTROLLED INSURANCE PROGRAM

FPL and Contractor agree that FPL may substitute its own Owner's Controlled Insurance Program ("OCIP") for the purpose of providing during the term of the Agreement Worker's Compensation insurance, Commercial General Liability insurance and other insurance requested by FPL that is typically covered by OCIPs. In such event, FPL shall procure and pay the costs for certain insurance coverages on behalf of Contractor and Subcontractors.

ARTICLE X.
SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE

10.1 GENERAL.

10.1.1 All start-up, synchronization, operation and testing conducted by Contractor shall be in accordance with the Contract Documents, applicable manufacturers' instructions and warranty requirements, Applicable Laws, Applicable Standards, Applicable Permits, Prudent Utility Practices and any and all applicable rules as agreed to by FPL and Contractor. Contractor shall provide FPL with at least thirty (30) days' advance written notice of the first Test that involves delivering energy to the Grid. In addition, no Test of the Plant that delivers electrical output shall be conducted unless Contractor gives prior written notice thereof as provided in Section 10.1.2, Test Notice. FPL, Financing Parties, the Utility, the Independent Engineer, all relevant Government Authorities and their respective authorized representatives shall have the right to inspect the Work and to be present during the start-up, synchronization, operation and testing of the Project pursuant to this Article.

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10.1.2 Test Notice.

(a) Prior to performing any Test, Contractor shall deliver to FPL a written notice thereof (a "Test Notice") specifying a date for commencement of any or all of the Tests. Contractor shall coordinate with FPL the scheduling of any Test and FPL shall coordinate such Test with the dispatch schedule for the Plant, so as not to interfere with FPL's or its Affiliates' obligations with respect thereto. Contractor shall deliver a Test Notice at least ten (10) Business Days prior to the commencement of any Test. FPL shall, within five (5) Business Days after its receipt of such Test Notice, deliver to Contractor a written notice:

(i) Accepting such Test Notice; or

(ii) Denying that the prerequisites for performing such Test have been completed and stating the facts upon which such reasonable denial is based.

(b) Upon receipt of notice denying that the prerequisites for performing such Test have been completed, Contractor shall take such action as is appropriate to remedy the conditions described in such notice from FPL. Following any such remedial action, Contractor shall deliver to FPL a new Test Notice conforming to the requirements of this Section 10.1.2, and the provisions of this Section 10.1.2, shall apply with respect to such new Test Notice in the same manner as they applied with respect to the original Test Notice.

(c) The foregoing procedure shall be repeated as often as necessary until FPL no longer rejects the Test Notice; provided, however, if Contractor is required to notify following receipt of FPL's written notice in which FPL denies that the prerequisites for performing a task have been completed, such renotification may be given within five (5) Business Days of such notice by FPL, and FPL shall have three (3) Business Days following the receipt of such resubmitted notice to file written objections as described above. Contractor shall reschedule Tests as requested by FPL to reasonably accommodate the schedules of Persons whom FPL deems necessary to attend the Tests. Contractor shall promptly notify FPL of any proposed change in the schedule of Tests and may not conduct any such test under such proposed changed schedule unless FPL receives reasonable advance notice of the actual date of commencement of such rescheduled test. FPL shall be responsible for notifying the Utility, the Financing Parties and the Independent Engineer for witnessing Tests. Contractor shall reimburse FPL for all additional direct costs reasonably and necessarily incurred by FPL due to Contractor's failure to provide written notice in accordance with this Section 10.2, or due to Contractor's failure to prepare any portion of the Work for inspections or testing after having provided notice to FPL of any such inspection or test.

10.2 SYNCHRONIZATION

Together with the notice of the Scheduled Synchronization Date, Contractor shall provide FPL a start-up and test schedule for the Project and copies of all manufacturers' specifications, schedules of protection schemes, and protection relay settings. Contractor shall promptly give FPL notice of any expected change in the Scheduled Synchronization Date or other information provided with the notice as described above (or any modifications thereto); provided that Contractor shall provide at least ten (10) days prior written notice of the actual synchronization date. Contractor shall perform the synchronization procedures in accordance with the Scope of Work and FPL's direction regarding Utility's requirements. Utility and its authorized representatives shall have the right to be present during the synchronization.

10.3 MECHANICAL COMPLETION

Upon satisfaction of all requirements for Mechanical Completion, Contractor shall provide FPL with a notice of Mechanical Completion. Within three (3) Business Days of receipt of such notice, FPL shall notify Contractor in writing whether or not Contractor has fulfilled the requirements of Mechanical Completion. If Contractor has not fulfilled such requirements for Mechanical Completion, FPL shall specify in such notice to Contractor in reasonable detail the reasons that the requirements for Mechanical Completion have not been met. Contractor shall promptly act to correct such deficiencies so as to achieve Mechanical Completion as soon as possible (and no later than by the applicable date set forth in Appendix C, Critical Milestones and

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Milestones, if such date has not already passed). Following any such remedial action, Contractor shall deliver to FPL a new notice of Mechanical Completion and the provisions of this Section 10.3, shall apply with respect to such new Mechanical Completion notice in the same manner as they applied to the original Mechanical Completion notice so long as, if the Guaranteed Provisional Acceptance Date shall have passed, Contractor is paying Schedule Liquidated Damages when due in accordance with Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

10.4 PERFORMANCE TESTS

10.4.1 Contractor is responsible for conducting the Tests and any required re-tests for the purposes of determining achievement of the Minimum Performance Level and the Final Acceptance Performance Level. Only after the Project:

(a) Has achieved Mechanical Completion;

(b) Has been synchronized with the Grid in accordance with the Scope of Work and Utility's requirements;

(c) Is capable of being operated safely, normally, reliably and continuously in accordance with the requirements of the Contract Documents at all operating conditions and modes specified in the Scope of Work (although minor portions of the Project not essential to its safe, continuous and reliable operation may remain to be completed); and

(d) Is ready for the Tests to be performed in accordance with the Contract Documents,

shall Contractor conduct the Tests.

10.4.2 Each Test shall be conducted in accordance with the terms of the Contract Documents, including the Scope of Work and Appendix HH, after complying with the notice provisions of Section 10.1.2, Test Notice. If the Project achieves the Minimum Performance Level, Contractor shall, upon satisfaction of the other requirements to Provisional Acceptance, submit a notice of Provisional Acceptance in accordance with Section 10.7, PROVISIONAL ACCEPTANCE. If the Project fails all or any part of the Tests, including, without limitation, the failure to achieve the Minimum Performance Level, Contractor shall take appropriate corrective action and the Tests shall be performed again. If the Project fails all or any part of the retest, Contractor shall take appropriate corrective action and the Tests shall be repeated. If Contractor fails to achieve the Minimum Performance Level and satisfy all of the other requirements of Provisional Acceptance on or prior to the Guaranteed Provisional Acceptance Date, Contractor shall pay Schedule Liquidated Damages in accordance with Section 11.2, SCHEDULE LIQUIDATED DAMAGES, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES. In addition, Contractor shall repeat the Tests in accordance with Section 11.6.1 during the applicable time periods set forth in Section 11.1, COMPLETION GUARANTEE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES. Contractor shall provide a written report of the results of each Test to FPL.

10.5 PERFORMANCE SHORTFALLS.

10.5.1 Prior to the Guaranteed Provisional Acceptance Date, if the Project has achieved the Minimum Performance Level necessary for Provisional Acceptance, as determined pursuant to Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES (but not the Final Acceptance Performance Level), and the Project is capable of being operated safely, normally and continuously in accordance with the requirements of the Contract Documents at all operating levels specified in the Scope of Work (although minor portions of the Project not essential to its safe, continuous and reliable operation may remain to be completed), and after complying with the notice provisions of Section 10.1.2, Test Notice, Contractor may conduct the Tests again in accordance with the terms of the Contract Documents, including the Scope of Work, in order to attempt to achieve the Final Acceptance Performance Level. If the Project fails to achieve all or any part of the Final Acceptance Performance Level after the Guaranteed Provisional Acceptance Date, Contractor shall, subject to Contractor's rights set forth in the following sentence, submit a Remedial Plan reasonably acceptable to FPL and take appropriate corrective action and repeat the Tests. If the Project fails all or any part of the

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Final Acceptance Performance Level after the Guaranteed Provisional Acceptance Date but all other requirements for Final Acceptance have been met, including the achievement of the Minimum Performance Level, Contractor shall have the option of:

(a) Submitting a Remedial Plan reasonably acceptable to FPL and take appropriate corrective action and repeat the Tests; or

(b) Giving notice to FPL of its declaration of Final Acceptance and reducing the Contract Price based on the results of the last Guaranteed Performance Test performed (and during which the Noise Guarantee was simultaneously satisfied) prior to the issuance of such notice.

If Contractor selects option (b), above, (i) the Contract Price will be reduced to an amount equal to the Contract Price multiplied by the Payment Output Percentage and (ii) Contractor shall perform all Remediation Work requested by FPL related to Work not associated with the percentage of the Final Acceptance Performance Level that has been achieved. For example, if 75% of the Final Acceptance Performance Level is achieved, to the extent requested by FPL, Work not associated with achieving such 75% of the Final Acceptance Performance Level (such Work being referred to as the "Non-Accepted Work") shall be removed from the Property Site and the Property Site on which such Non-Accepted Work is located or performed shall be restored to the condition of the Property Site immediately prior to Initial Site Mobilization to the extent requested by FPL.

10.5.2 Notwithstanding the foregoing and subject to the terms and conditions contained herein, Contractor may repeat the Tests until the earliest of the:

(a) Date that is one hundred and eighty (180) days after the Guaranteed Provisional Acceptance Date;

(b) Achievement by Contractor of the Final Acceptance Performance Level; or

(c) Delivery by Contractor to FPL of Contractor's notice of declaration of Final Acceptance and reduction of the Contract Price in accordance with Section 10.5.1.

Contractor shall provide a written report of the results of each Test to FPL. The Minimum Performance Level, the Final Acceptance Performance Level and any other Net Energy Output used to calculate any reduction of Contract Price shall be achieved only while the Plant is operating in compliance with the Noise Guarantee (excluding for this purpose all waivers and variances permitted under Applicable Permits).

10.5.3 If the Final Acceptance Performance Level is not achieved within one hundred and eighty (180) days after the Guaranteed Provisional Acceptance Date and Contractor has not selected option (b) of Section 10.5.1, then the Contract Price will be automatically reduced to an amount equal to the Contract Price multiplied by the Payment Output Percentage, which Payment Output Percentage shall be based on the results of the last Guaranteed Performance Test performed (and during which the Noise Guarantee was simultaneously satisfied) prior to one hundred and eighty (180) days after the Guaranteed Provisional Acceptance Date.

10.5.4 At no time between the Provisional Acceptance Date and Final Acceptance shall the performance of the Project fall below the Minimum Performance Level, for reasons not due to FPL's operation of the Project or a Force Majeure Event.

10.6 PUNCH LIST.

10.6.1 At all times during performance of the Work, Contractor shall maintain a list setting forth parts of the Work which remain to be performed in order to confirm that the Work fully complies with the terms of the Contract Documents. Contractor shall promptly provide a copy of such list to FPL upon request. Contractor shall make such revisions to such list as and when requested by FPL from time to time.

10.6.2 No later than thirty (30) days before the Provisional Acceptance Date, Contractor shall prepare and submit to FPL a comprehensive list (the "Punch List") of items to be completed for the Project to reach Final Acceptance. The Punch List shall not include any item that affects the safety, reliability or operability of the Equipment, the Plant or any portion thereof or requires a shut-down or reduced operation of the

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Equipment, the Project or any portion thereof to be completed. Contractor shall make such revisions to the Punch List as and when reasonably requested by FPL from time to time.

10.6.3 The Parties agree that with respect to Punch List items that remain uncompleted and which are preventing Final Acceptance, it may be more expedient for FPL to complete such Punch List items, at its election and option. If the Parties are able to agree upon the commercial value of all items on the Punch List, and FPL so elects, at its sole discretion, FPL may, in lieu of requiring Contractor to complete any item on the Punch List, require Contractor to pay to FPL an amount equal to one hundred fifty percent (150%) of the commercial value of such Punch List item as reasonably determined by FPL. FPL shall have the right to offset such amount owed by Contractor against any amounts owed by FPL to Contractor at Final Acceptance, or otherwise under the Contract Documents.

10.7 PROVISIONAL ACCEPTANCE.

10.7.1 After completing the Tests in accordance with Section 10.4, TESTS, and Contractor determines that all of the requirements for Provisional Acceptance have been completed, Contractor shall provide written notice thereof to FPL.

10.7.2 Within three (3) Business Days following receipt by FPL of such notice of Provisional Acceptance, FPL shall notify Contractor in writing whether or not Contractor has fulfilled the requirements of Provisional Acceptance. If Contractor has fulfilled the requirements of Provisional Acceptance, FPL shall notify Contractor that it has achieved Provisional Acceptance. If Contractor has not fulfilled such requirements for Provisional Acceptance, FPL shall specify in such notice to Contractor in reasonable detail the reasons for determining that the requirements for Provisional Acceptance have not been met. Contractor shall promptly act to correct such deficiencies so as to achieve Provisional Acceptance as soon as possible (and no later than by the Guaranteed Provisional Acceptance Date if such date has not already passed). Following any such remedial action, Contractor shall deliver to FPL a new notice of Provisional Acceptance and the provisions of this Section 10.7.2, shall apply with respect to such new Provisional Acceptance notice in the same manner as they applied to the original Provisional Acceptance notice. The foregoing procedure shall be repeated as often as necessary, so long as Contractor is paying when due Schedule Liquidated Damages (if applicable), until acceptance by FPL of Contractor's Provisional Acceptance notice and delivery by FPL of its own notice to Contractor that Provisional Acceptance has been achieved. The date on which Provisional Acceptance is achieved by Contractor shall be the "Provisional Acceptance Date."

10.8 FINAL ACCEPTANCE OF THE PLANT

After achieving Provisional Acceptance in accordance with Section 10.7, PROVISIONAL ACCEPTANCE, when Contractor determines that all of the requirements for Final Acceptance have been completed (other than execution of the Final Acceptance Certificate by FPL), or when Contractor has elected to or is required to declare Final Acceptance pursuant to Section 10.5, PERFORMANCE SHORTFALLS, Contractor shall submit a proposed Final Acceptance Certificate, in substantially the form attached hereto as Appendix G, Form of Final Acceptance Certificate, to FPL. As soon thereafter as reasonably practicable, a team consisting of representatives of FPL, the Financing Parties, the Independent Engineer and Contractor shall make a final inspection of the Plant. Within ten (10) Business Days following such final inspection, FPL, with the consent of the Financing Parties, if applicable, shall notify Contractor in writing whether Contractor has fulfilled the requirements of the Contract Documents to reach Final Acceptance (other than execution of the Final Acceptance Certificate by FPL). If such requirements have been fulfilled, FPL will execute the proposed Final Acceptance Certificate. If the requirements for Final Acceptance have not been fulfilled, then FPL shall deliver a written notice to such effect to Contractor describing in reasonable detail the deficiencies noted and corrective action recommended, including projected target dates for the completion of such incomplete or remedial Work. Contractor shall promptly act to correct any such deficiencies. The procedure set forth in this Section 10.8, shall be repeated as necessary, until the earlier of: (i) the date on which Contractor has fulfilled the requirements for the issuance of the Final Acceptance Certificate and FPL executes such certificate; or (ii) termination of this Agreement.

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benefit of Contractor, in such order as FPL may elect in its sole discretion. In addition, FPL, in its sole discretion, may collect Schedule Liquidated Damages by drawing on the Letter of Credit if not timely paid by Contractor.

11.6 DETERMINATION OF PERFORMANCE.

11.6.1 Contractor's compliance with the Minimum Performance Level for purposes of achieving Provisional Acceptance shall be determined on the basis of the Tests conducted in accordance with Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE, and Appendix HH, and the results of such Tests shall be conclusive for such purpose. The Net Energy Output of the Plant shall be determined pursuant to the Guaranteed Performance Test and shall be measured while the Plant is operating in compliance with the Noise Guarantee (excluding for this purpose all waivers and variances permitted under Applicable Permits).

11.6.2 Contractor's compliance with the Minimum Performance Level and the Guaranteed Performance Level, or the extent of its failure to comply therewith, for purposes of achieving Final Acceptance shall be determined on the basis of the Tests conducted in accordance with Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE, and Appendix HH, and the results of such tests shall be conclusive for such purpose. The Net Energy Output of the Plant shall be determined pursuant to the Guaranteed Performance Test and shall be measured while the Plant is operating in compliance with the Noise Guarantee (excluding for this purpose all waivers and variances permitted under Applicable Permits).

11.7 ABSOLUTE OBLIGATIONS

The Parties understand and agree that Contractor's obligation to achieve the Minimum Performance Level simultaneously with achievement of the Noise Guarantee, is an absolute obligation, which must be achieved. Notwithstanding anything contained herein to the contrary, after the Project has achieved Provisional Acceptance and during the time period prior to Final Acceptance, the Project shall be capable of being operated in accordance with all of the Plant's operating procedures and all Applicable Laws, Applicable Permits and the other requirements of the Contract Documents, and all operating conditions specified in the Scope of Work, excluding for this purpose all waivers and variances permitted under Applicable Permits. The obligations set forth in this Section 11.7 are absolute obligations of Contractor regardless of the amounts and expenses required to be incurred by Contractor to satisfy such obligation, and notwithstanding that such amounts may exceed the Contract Price.

11.8 PARENT GUARANTY

Contractor's ultimate corporate parent is SunPower Corporation (the "Contractor Parent Company"). Concurrently with the execution of this Agreement, Contractor shall provide to FPL an irrevocable, unconditional guarantee in the form of Appendix I, Form of Contractor Parent Guaranty, duly executed by Contractor Parent Company for the benefit of FPL and the Financing Parties under terms and conditions acceptable to FPL and the Financing Parties ("Contractor Parent Guaranty"). In order to provide FPL and the Financing Parties with evidence of Contractor's and Contractor Parent Company's financial ability to complete the Project, Contractor agrees to comply with reasonable requests for financial information. After the Letter of Credit Termination Date, upon the occurrence of a Credit Trigger Event, at FPL's request, Contractor shall provide a Letter of Credit with a stated amount (or post other collateral, including cash in an amount) determined pursuant to paragraph 3 of Appendix E attached hereto in addition to the Contractor Parent Guaranty.

ARTICLE XII.
CONTRACTOR'S WARRANTIES

12.1 WARRANTIES.

12.1.1 Contractor warrants to FPL that all Equipment shall:

(a) Be new and of good quality;

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12.2.2 If Contractor fails to commence to complete the correction of any Defect or cure of any breach of warranty as required herein within five (5) days after receipt of notice from FPL to perform such obligations or thereafter fails to diligently continue to complete such corrections or cure, then FPL may correct (or cause to be corrected) such Defect or cure (or cause to be cured) such breach of warranty and Contractor shall be liable for all reasonable costs, charges, and expenses incurred by FPL in connection therewith (including attorneys' and other consultants' fees), and Contractor shall, within fifteen (15) days after request therefor, pay to FPL an amount equal to such costs, charges, and expenses. Any such request by FPL shall be accompanied by proper documentation evidencing such costs, charges and expenses. Such correction of a Defect or cure of a breach of warranty by FPL (or caused by FPL) shall be deemed performed by Contractor and the Warranty Period applicable thereto for such corrected or cured Work shall be extended in accordance with Section 12.1.4.

12.2.3 If, during the a given Warranty Period, Contractor shall change, repair or replace any Major Equipment item or component, FPL, in its reasonable discretion, may require Contractor to conduct and satisfactorily complete any test required by FPL with respect to the affected Equipment; provided, however, in connection with any performance of a test pursuant to this Section 12.2.3, appropriate allowance with respect to the performance of such Equipment shall be made for the fact that such Equipment may have operated prior thereto. If after running such test pursuant to this Section, the results indicate a degradation in the performance of the Project (as measured against the test results used to satisfy the requirements of Section 12.1.3) or the Project fails to satisfy any other Test, then Contractor shall repair, correct or replace such affected Equipment and re-run such test until the Project performs at a level consistent with the performance of the Project immediately prior to the change, repair or replacement of such Equipment.

12.3 PROPRIETARY RIGHTS

Without limiting any of the provisions of this Agreement, if FPL or Contractor is prevented from completing the Plant, the Work or any part thereof, or from the use, operation, or enjoyment of the Plant, the Work or any part thereof as a result of a claim, action or proceeding by any Person for unauthorized disclosure, use, infringement or misappropriation of any Intellectual Property Right arising from Contractor's performance (or that of its Subcontractors or Vendors) under the Contract Documents, including, without limitation, the Work, Equipment, the Contractor Deliverables or other items and services provided by Contractor or any Subcontractor or Vendor hereunder, Contractor shall promptly, but in no event later than thirty (30) days from the date of any action or proceeding, take all actions necessary to remove such impediment, including:

12.3.1 Secure termination of the injunction and procure for FPL or its Affiliates or assigns, as applicable, the right to use such materials, Equipment or Contractor Deliverables in connection with the operation and maintenance of the Project, without obligation or liability; or

12.3.2 Replace such materials, Equipment or Contractor Deliverables, with a non-infringing equivalent, or modify same to become non-infringing,

All at Contractor's sole expense, but subject to all the requirements of the Contract Documents.

12.4 REPAIRS AND TESTING BY FPL.

12.4.1 During the Warranty Period, without prior notice to Contractor and without affecting the warranties of Contractor hereunder, FPL shall be permitted to:

(a) Make repairs or replacements on Equipment so long as the repair or replacement involves the correct installation of spare parts and is otherwise conducted in accordance with the operation and maintenance manuals, the manufacturer specifications and the Procedures Manual; and

(b) Adjust or test Equipment as outlined in the instruction manuals provided by Contractor or any Subcontractor or Vendor.

12.4.2 In the event of an emergency and if, in the reasonable judgment of FPL, the delay that would result from giving notice to Contractor could cause serious loss or damage which could be prevented by immediate action, any action (including correction of Defects) may be taken by FPL or a third party chosen by FPL, without giving prior notice to Contractor, and in the case of a Defect, the reasonable cost of correction shall

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be paid by Contractor. In the event such action is taken by FPL, Contractor shall be promptly notified within five (5) Business Days after correction efforts are implemented, and shall assist whenever and wherever possible in making the necessary corrections.

12.5 VENDORS AND SUBCONTRACTORS

Contractor shall, for the protection of Contractor and FPL, obtain from the Vendors and Subcontractors such guarantees and warranties with respect to Work performed and Equipment supplied, used and installed hereunder as are reasonably obtainable, which guarantees and warranties shall equal or exceed those set forth in Section 12.1, WARRANTIES, and shall be made available and assignable to FPL and the Financing Parties to the full extent of the terms thereof upon the expiration of Contractor's warranty hereunder. FPL shall be an express third party beneficiary of all such guarantees and warranties. All such warranties obtained shall be in addition to, and shall not alter the warranties of, Contractor. Upon FPL's request, Contractor shall use all reasonable efforts to force Subcontractors to honor warranties including, but not limited to, filing suit to enforce same. To the extent available, FPL shall have the right to require Contractor to secure additional warranty or extended guarantee protection pursuant to a Change Order issued in accordance with the provisions of Article VI, CHANGE ORDERS. Upon the earlier of the Provisional Acceptance Date or termination of this Agreement, Contractor shall deliver to FPL copies of all relevant contracts providing for such guarantees and warranties.

12.6 ASSIGNMENT OF WARRANTIES

Upon the expiration of all of the Warranty Periods or termination of this Agreement, Contractor shall assign to FPL all warranties received by it from Subcontractors and Vendors or otherwise obtained under Section 12.5, VENDORS AND SUBCONTRACTORS (or the Plant or Work in the event of termination of this Agreement). Such assignment of warranties to FPL must also allow FPL to further assign such warranties. However, in the event that FPL makes any warranty claim against Contractor with respect to Equipment or services supplied in whole or in part by any Subcontractor or Vendor, and Contractor fulfills its obligations with respect to such claim by FPL, Contractor shall be entitled to enforce for its own benefit any warranty given by such Subcontractor or Vendor with respect to such Equipment and services.

12.7 SURVIVAL OF WARRANTIES

The provisions of this Article shall survive the expiration or termination of this Agreement.

ARTICLE XIII.
REPRESENTATIONS

13.1 REPRESENTATIONS AND WARRANTIES.

13.1.1 Contractor represents and warrants to FPL that:

(a) Contractor is a corporation, duly organized, validly existing, and in good standing under the laws of the State of Delaware and is duly authorized and qualified to conduct business in the State of Florida;

(b) Contractor has all requisite power and authority to conduct its business, own its properties and execute and deliver this Agreement and perform its obligations hereunder in accordance with the terms hereof;

(c) The execution, delivery, and performance of the Contract Documents have been duly authorized by all requisite corporate action and this Agreement constitutes the legal, valid and binding obligation of Contractor, enforceable against Contractor in accordance with its terms;

(d) Neither the execution, delivery or performance of the Contract Documents conflicts with, or results in a violation or breach of the terms, conditions or provisions of, or constitutes a default under, the organizational documents of Contractor or any agreement, contract, indenture or other instrument under which Contractor or its assets are bound, nor violates or conflicts with any Applicable Law or any judgment, decree, order, writ, injunction or award applicable to Contractor;

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(e) Contractor is not in violation of any Applicable Law or Applicable Permit, which violations, individually or in the aggregate, would affect its performance of its obligations under the Contract Documents;

(f) Except as described in Section 18.21, Contractor's License, Contractor is the holder of all governmental consents, licenses, permissions and other authorizations and Applicable Permits required to operate and conduct its business now and as contemplated by the Contract Documents, other than Contractor Permits and FPL Permits which will be obtained in accordance with the terms of the Contract Documents;

(g) There is no pending controversy, legal action, arbitration proceeding, administrative proceeding or investigation instituted, or to the best of Contractor's knowledge threatened, against or affecting, or that could affect, the legality, validity and enforceability of the Contract Documents or the performance by Contractor of its obligations under the Contract Documents, nor does Contractor know of any basis for any such controversy, action, proceeding or investigation;

(h) Contractor has examined this Agreement, including all Appendices attached hereto, thoroughly and become familiar with all its terms and provisions;

(i) Contractor, by itself and through its Subcontractors and Vendors, has the full experience and proper qualifications to design and perform the Work and to construct the Plant in accordance with the terms of the Contract Documents;

(j) Contractor has visited and examined the Property Site and is fully familiar with such Property Site and surrounding area and based on such visit and examination has no reason to believe that Contractor will be unable to complete the Work in accordance with the Contract Documents;

(k) To the best of its knowledge, Contractor has reviewed all other documents and information necessary and available to Contractor in order to ascertain the nature, location and scope of the Work, the character and accessibility of the Property Site, the existence of obstacles to construction of the Plant and performance of the Work, the availability of facilities and utilities, and the location and character of existing or adjacent work or structures;

(l) Contractor owns or has the right to use all patents, trademarks, service marks, tradenames, copyrights, licenses, franchises, permits and intellectual property rights necessary to perform the Work without conflict with the rights of others;

(m) Each of Contractor and the Contractor Parent Company is financially solvent, able to pay its debts as they mature, and possessed of sufficient working capital to complete its obligations under this Agreement;

(n) FPL may provide or may have provided Contractor with copies of certain studies, reports or other information (including oral statements) and Contractor represents and acknowledges that:

  (i) All such documents or information have been or will be provided as background information and as an accommodation to Contractor;

  (ii) FPL makes no representations or warranties with respect to the accuracy of such documents or the information (including oral statements) or opinions therein contained or expressed; and

  (iii) It is not relying on FPL for any information, data, inferences, conclusions, or other information with respect to the Job Site (other than the boundary survey referred to in Section 4.7, DESCRIPTION OF PROPERTY SITE), including the surface conditions of the Job Site and the surrounding areas;

(o) All Persons who will perform any portion of the Work have and will have all business and professional certifications required by Applicable Law to perform their respective services under this Agreement;

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(p) The access rights granted to or obtained by Contractor to the Job Site are adequate for the performance of the Work and operation of the Plant; and

(q) The Plant will be designed and constructed to achieve or exceed the Net Energy Output Guarantee.

13.1.2 FPL represents and warrants to Contractor that:

(a) FPL is a corporation, duly organized, validly existing, and in good standing under the laws of Florida and is duly authorized and qualified to conduct business in the State of Florida;

(b) FPL has all requisite power and authority to conduct its business, own its properties and execute and deliver the Contract Documents and perform its obligations hereunder in accordance with the terms hereof;

(c) The execution, delivery, and performance of the Contract Documents have been duly authorized by all requisite corporation action and this Agreement constitutes the legal, valid and binding obligation of FPL, enforceable against FPL in accordance with its terms;

(d) Neither the execution, delivery or performance of the Contract Documents conflicts with, or results in a violation or breach of the terms, conditions or provisions of, or constitutes a default under, the organizational documents of FPL or any agreement, contract, indenture or other instrument under which FPL or its assets are bound, nor violates or conflicts with any Applicable Law or any judgment, decree, order, writ, injunction or award applicable to FPL;

(e) FPL is not in violation of any Applicable Law or Applicable Permit, which violations, individually or in the aggregate, would affect its performance of its obligations under the Contract Documents; and

(f) FPL is the holder of all governmental consents, licenses, permissions and other authorizations and Applicable Permits required to operate and conduct its business now and as contemplated by the Contract Documents, other than FPL Permits which will be obtained in accordance with the terms of the Contract Documents.

13.2 SURVIVAL OF REPRESENTATIONS AND WARRANTIES

The representations and warranties of the Parties herein shall survive execution and termination of this Agreement.

ARTICLE XIV.
FORCE MAJEURE AND FPL CAUSED DELAY

14.1 DEFINITION OF FORCE MAJEURE EVENT

14.1.1 As used herein, the term "Force Majeure Event" shall mean any event or circumstance, or combination of events or circumstances, that arises after the date hereof, is beyond the reasonable control of the Party claiming the Force Majeure Event, is unavoidable or could not be prevented or overcome by the reasonable efforts and due diligence of the Party claiming the Force Majeure Event and has an impact which will actually, demonstrably, adversely and materially affect such Party's ability to perform its obligations in accordance with the terms of the Contract Documents or has an impact which will actually, demonstrably, adversely and materially affect the Critical Path of the Work and performance of its obligations in accordance with the terms of the Contract Documents. Without limiting the generality of the foregoing, events that may give rise to a Force Majeure Event include, without limitation:

(a) Acts of God;

(b) Natural disasters;

(c) Fires;

(d) Earthquakes;

(e) Lightning;

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(f) Floods;

(g) Storms;

(h) Civil disturbances;

(i) Terrorism;

(j) Riots;

(k) War; and

(l) The action of or failure to act on the part of any Government Authority having or asserting jurisdiction that is binding upon the Parties and has been opposed by all reasonable means,

In each case, that meet the definition of Force Majeure Event as set forth above.

14.1.2 Notwithstanding the foregoing, the term "Force Majeure Event" does not include, without limitation:

(a) Strikes, work stoppages (or deteriorations), slowdowns or other labor actions, unless such strike, work stoppage or other labor action is a result of strike, work stoppage or other labor action originated by employees of the Party not claiming the Force Majeure Event;

(b) Any labor or manpower shortages;

(c) Unavailability, late delivery, failure, breakage or malfunction of equipment or materials or events that affect the cost of equipment or materials;

(d) Economic hardship (including lack of money);

(e) Perils of sea;

(f) Delays in transportation (including delays in clearing customs) other than delays in transportation resulting from accidents or closure of roads or other transportation route by Government Authorities;

(g) Changes in Applicable Laws;

(h) Weather conditions normally experienced in the geographic area of the Project, it being the intent of the Parties that only when the number of days lost as a result of adverse weather (as reported by the National Weather Service or a similar agency) exceeds the number usually encountered in the geographic area of the Project for any given month based on a ten (10) year average (as reported by the National Weather Service or a similar agency) will Contractor be allowed to claim a Force Majeure Event, subject however to the other requirements for an event or occurrence to be Force Majeure Event and the other requirements set forth in this Article;

(i) Actions of a Government Authority with respect to Contractor's compliance with Applicable Laws or Applicable Permits;

(j) Any failure by Contractor to obtain and/or maintain any Applicable Permit it is required to obtain and/or maintain hereunder;

(k) Any other act, omission, delay, default or failure (financial or otherwise) of a Subcontractor or Vendor; or

(l) Any surface or subsurface conditions at the Property Site (subject to Contractor's rights as provided in Section 3.4.4, Differing Condition, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR).

14.1.3 Notwithstanding the foregoing and solely for the purpose of conducting the acceptance testing provided for in Section 2 of Appendix HH – Acceptance Testing, the term "Force Majeure Event" includes solar conditions that do not meet the express criteria set forth in in Section 2 of Appendix HH – Acceptance

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Testing, subject however to the other requirements for an event or occurrence to be Force Majeure Event and the other requirements set forth in this Article.

14.2 NOTICE OF FORCE MAJEURE EVENT

The Party claiming a Force Majeure Event shall within five (5) Business Days after it knows or should have known of the occurrence of the Force Majeure Event (or in any event, no later than twenty (20) days after the commencement of the Force Majeure Event), give the other Party written notice describing the details of the cause and nature of the Force Majeure Event, the anticipated length of delay due to the Force Majeure Event and any other affect on the Party's performance of its obligations hereunder; provided that if the Force Majeure Event results in a breakdown of communications rendering it not reasonably practicable to give notice within the applicable time limit specified herein, then the Party claiming a Force Majeure Event shall give such notice as soon as reasonably practicable after the reinstatement of communications, but no later than five (5) Business Days after such reinstatement. Within fifteen (15) days after initial notification, such Party shall provide sufficient proof of the occurrence and duration of such Force Majeure Event to the other Party and shall thereafter provide the other Party with periodic supplemental updates to reflect any change in information given to the other Party as often as requested by the other Party. The Party claiming the Force Majeure Event shall give notice to the other Party of: (i) the cessation of the relevant Force Majeure Event; and (ii) the cessation of the effects of such Force Majeure Event on the performance by it of its obligations under the Contract Documents as soon as practicable after becoming aware thereof. No Force Majeure Event shall relieve any Party from performing those of its obligations that are not affected by the Force Majeure Event.

14.3 DELAY FROM FORCE MAJEURE EVENT

14.3.1 So long as the conditions set forth in this Section 14.3 are satisfied, and subject to Section 14.7, PERFORMANCE NOT EXCUSED, neither Party shall be responsible or liable for, or deemed in breach of this Agreement because of, any failure or delay in complying with its obligations under or pursuant to the Contract Documents to the extent that such failure has been caused, or contributed to, by one or more Force Majeure Events or its effects or by any combination thereof, and in such event:

(a) Except as otherwise provided herein, the performance by the Party claiming the Force Majeure Event of its obligations hereunder shall be suspended, and in the event that such Party is required to start or complete an action during a specific period of time, such start date or period for completion shall be extended, on the condition that:

(i) Such suspension of performance and extension of time shall be of no greater scope and of no longer duration than is required by the effects of the Force Majeure Event;

(ii) The Party claiming the Force Majeure Event complies with Section 14.2, NOTICE OF FORCE MAJEURE EVENT; and

(iii) The Party claiming the Force Majeure Event continually uses commercially reasonable efforts to alleviate and mitigate the cause and effect of the Force Majeure Event and remedy its inability to perform; and

(b) In the event Contractor desires to claim a Force Majeure Event, it must submit a request for Changes pursuant to Section 6.2, CHANGE ORDERS REQUESTED BY CONTRACTOR, of Article VI, CHANGE ORDERS.

14.3.2 Solely with respect to a Force Majeure Event described in Section 14.1.3, if such Force Majeure Event continues for sixty (60) consecutive days from the commencement of acceptance testing, then, solely for purposes of Section 11.2, FPL shall deem Contractor to have satisfied the Minimum Performance Level and Schedule Liquidated Damages shall not be payable. In such event, Contractor shall not be deemed to have achieved Provisional Acceptance until solar conditions exist that meet the express criteria set forth in in Section 2 of Appendix HH – Acceptance Testing and the Minimum Performance Level is achieved in accordance with Section 11.6.

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14.3.3 Contractor's failure to comply with this Section 14.3, shall constitute a waiver of any claims as a result of a Force Majeure Event.

14.4 REMOVAL OF FORCE MAJEURE

If, within a reasonable time after a Force Majeure Event that has caused Contractor to suspend or delay performance of the Work, action to be undertaken at the expense of FPL has been identified and recommended to Contractor, and Contractor has failed within five (5) days after receipt of notice thereof from FPL to take such action as Contractor could lawfully and reasonably initiate to remove or relieve either the Force Majeure Event or its direct or indirect effects, FPL may, in its sole discretion and after notice to Contractor, initiate such reasonable measures as will be designed to remove or relieve such Force Majeure Event or its direct or indirect effects and thereafter require Contractor to resume full or partial performance of the Work. To the extent Contractor's failure to take such measures results in expense in addition to what FPL would have paid to Contractor (whether as part of the original Contract Price or as additional compensation to the extent the requested measures constituted a Change Order altering the scope of the Work) had Contractor taken such measures, such additional expense shall be for Contractor's account.

14.5 NOTICE OF FPL CAUSED DELAY

14.5.1 In the event Contractor desires to claim an FPL Caused Delay, Contractor shall within five (5) Business Days after it knows or should have known of the occurrence of the FPL Caused Delay, give FPL written notice describing the details of the FPL Caused Delay, the anticipated length of such delay and any other affect on Contractor's performance of its obligations hereunder. Within fifteen (15) days after initial notification, Contractor shall:

(a) Provide to FPL demonstrable proof of the occurrence and duration of such FPL Caused Delay and, if requested by FPL, such proof shall be provided, and in any event verified, by an independent third party reasonably acceptable to FPL and Contractor at the sole cost and expense of Contractor; and

(b) Thereafter provide FPL with periodic supplemental updates to reflect any change in information given to FPL as often as requested by FPL.

14.5.2 In the event that Contractor claims an FPL Caused Delay in violation of this provision, FPL shall be entitled to set-off against any payments due to Contractor or draw upon any security provided by Contractor (including the Letter of Credit) to compensate FPL for all costs (including reasonable attorneys' and other consultants' fees) incurred in enforcing this Section 14.5.

14.6 DELAY FROM FPL CAUSED DELAY

14.6.1 So long as the conditions set forth in this Section 14.6, are satisfied and subject to Section 14.7, PERFORMANCE NOT EXCUSED, Contractor shall not be responsible or liable for, or deemed in breach of the Contract Documents because of, any failure or delay in completing the Work in accordance with the Project Schedule or achieving Provisional Acceptance by the Guaranteed Provisional Acceptance Date to the extent that such failure has been caused by one or more FPL Caused Delays, and in such event, except as otherwise provided herein, the start date or period for completion of any portion of the Work shall be extended, on the condition that:

(a) Such suspension of performance and extension of time shall be of no greater scope and of no longer duration than is required by the effects of the FPL Caused Delay;

(b) Contractor complies with Section 14.5, NOTICE OF FPL CAUSED DELAY; and

(c) Contractor provides all assistance reasonably requested by FPL for the elimination or mitigation of the FPL Caused Delay.

14.6.2 In the event Contractor desires to claim an FPL Caused Delay, it must submit a request for Changes pursuant to Section 6.2, CHANGE ORDERS REQUESTED BY CONTRACTOR, of Article VI, CHANGE ORDERS, and Contractor shall be entitled to suspension of performance or extension of time (including an extension of the Guaranteed Provisional Acceptance Date) together with demonstrated, justified and

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reasonable additional costs incurred by reason of such delay to the extent agreed upon by both Parties pursuant to a Change Order in accordance with Section 6.2, CHANGE ORDERS REQUESTED BY CONTRACTOR, of Article VI, CHANGE ORDERS. Failure to comply with the terms of this Section 14.6, shall constitute a waiver of any claims for an increase in the Project Schedule or the Contract Price as a result of an FPL Caused Delay.

14.7 PERFORMANCE NOT EXCUSED

The payment of money owed shall not be excused because of a Force Majeure Event or FPL Caused Delay. In addition, a Party shall not be excused under this Article from timely performance of its obligations hereunder to the extent that the claimed Force Majeure Event or FPL Caused Delay was caused by any negligent or intentional acts, errors, or omissions, or for any breach or default of the Contract Documents by such Party. Furthermore, no suspension of performance or extension of time shall relieve the Party benefiting therefrom from any liability for any breach of the obligations that were suspended or failure to comply with the time period that was extended to the extent such breach or failure occurred prior to the occurrence of the applicable Force Majeure Event or FPL Caused Delay. Notwithstanding anything contained herein to the contrary, Contractor shall not withdraw Contractor's Equipment and personnel from the Job Site or otherwise demobilize without the prior authorization of FPL. Contractor shall not be entitled to receive reimbursement for its costs of demobilization and/or remobilization as a result of any Force Majeure Event.

ARTICLE XV.
TERMINATION

15.1 CONTRACTOR EVENTS OF DEFAULT

The occurrence of any of the following events shall constitute an event of default by Contractor (each a "Contractor Event of Default"):

15.1.1 The failure of Contractor, subject to the grace period provided in Section 11.1, COMPLETION GUARANTEE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, to achieve Provisional Acceptance by the Guaranteed Provisional Acceptance Date;

15.1.2 Intentionally Deleted.

15.1.3 The failure of Contractor to achieve Final Acceptance within two hundred and twenty five (225) days after the Guaranteed Provisional Acceptance Date;

15.1.4 The failure of the Plant to continue to operate at Minimum Performance Level after Provisional Acceptance and prior to Final Acceptance, unless such failure is caused by FPL's failure to properly operate and maintain the Plant in accordance with Contractor's written instructions provided hereunder;

15.1.5 The Plant, during the period of time between Provisional Acceptance and Final Acceptance, is not capable of being operated in accordance with Plant operating procedures and all Applicable Laws and Applicable Permits, and other requirements of the Agreement, and all operating conditions specified in the Scope of Work;

15.1.6 The failure by Contractor to pay liquidated damages as required herein;

15.1.7 Any failure by Contractor to make any other payment or payments required to be made to FPL under the Contract Documents within five (5) Business Days after receipt of written notice from FPL of Contractor's failure to make such other payment or payments (except, in the case of payments other than Schedule Liquidated Damages, to the extent Contractor disputes such other payment or payments in good faith and in accordance with the terms of this Agreement);

15.1.8 Any of the following occurs:

(a) Contractor fails to supply sufficient skilled workers or suitable materials or equipment;

(b) Contractor fails to make prompt payments when due to Subcontractors or Vendors for labor, materials or equipment;

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(c) Contractor suspends performance of a material portion of the Work (other than as provided in: (i) Article XIV, FORCE MAJEURE AND FPL CAUSED DELAY; (ii) Section 15.4.1, Suspension by FPL for Convenience, (iii) Section 15.7, TERMINATION BY CONTRACTOR DUE TO FPL DEFAULT; or (iv) pursuant to a Change Order); or

(d) Contractor fails to comply with any provision of any Applicable Law,

and if in each paragraph (a) through (d) of this Section, such condition remains unremedied for thirty (30) days following written notice thereof by FPL, or for such longer period, not to exceed sixty (60) days, during which time Contractor diligently pursues the cure of such material breach, if such material breach is capable of being cured;

15.1.9 The failure by Contractor to deliver any recovery plan described in Section 5.3.3, of Section 5.3, PROJECT SCHEDULE, of Article V, PROJECT SCHEDULE, within thirty (30) days after the date such recovery plan is due pursuant to the terms of such Section, or following approval of a recovery plan pursuant to such Section, the failure of Contractor to meet the schedule set forth in such recovery plan;

15.1.10 Any breach by Contractor of any representation or warranty made by Contractor in Article XIII, REPRESENTATIONS;

15.1.11 Any breach by Contractor of any obligation, covenant or agreement of Contractor hereunder other than those breaches specified in this Section 15.1, and:

(a) Such breach is not cured by Contractor within fifteen (15) days after notice thereof from FPL; or

(b) If such breach is not capable of being cured within such fifteen (15) day period (as determined by FPL in its sole discretion), Contractor fails to:

(i) Commence to cure such breach within such fifteen (15) day period;

(ii) Thereafter diligently proceed to cure such breach in a manner satisfactory to FPL in its sole discretion;

(iii) Cure such breach within ninety (90) days after notice thereof from FPL;

15.1.12 Any of the following occurs:

(a) Contractor or Contractor Parent Company consents to the appointment of or taking possession by, a receiver, a trustee, custodian, or liquidator of itself or of a substantial part of its assets, or fails or admits in writing its inability to pay its debts generally as they become due, or makes a general assignment for the benefit of creditors;

(b) Contractor or the Contractor Parent Company files a voluntary petition in bankruptcy or a voluntary petition or an answer seeking reorganization in a proceeding under any applicable bankruptcy or insolvency laws or an answer admitting the material allegations of a petition filed against it in any such proceeding, or seeks relief by voluntary petition, answer or consent, under the provisions of any now existing or future bankruptcy, insolvency or other similar law providing for the liquidation, reorganization, or winding up of corporations, or providing for an agreement, composition, extension, or adjustment with its creditors;

(c) A substantial part of Contractor's or the Contractor Parent Company's assets is subject to the appointment of a receiver, trustee, liquidator, or custodian by court order and such order shall remain in effect for more than thirty (30) days; or

(d) Contractor or the Contractor Parent Company is adjudged bankrupt or insolvent, has any property sequestered by court order and such order shall remain in effect for more than thirty (30) days, or has filed against it a petition under any bankruptcy, reorganization, arrangement, insolvency, readjustment of debt, dissolution or liquidation law of any jurisdiction, whether now or hereafter in effect, and such petition shall not be dismissed within thirty (30) days of such filing;

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15.1.13 The dissolution of Contractor, except for the purpose of merger, consolidation or reorganization where the successor expressly assumes Contractor's obligations hereunder and such assignment and assumption does not materially adversely affect the ability of the successor to perform its obligations under the Contract Documents and the Parent Guaranty remains in full force and effect for the obligations of such successor;

15.1.14 The transfer by Contractor of all or a substantial portion of the:

(a) Rights and/or obligations of Contractor hereunder, except for an assignment permitted hereunder; or

(b) Assets or obligations of Contractor, except where the transferee expressly assumes the transferred obligations and such transfer does not materially adversely affect the ability of Contractor or the transferee, as applicable, to perform its obligations under the Contract Documents, as determined by FPL in its sole discretion;

15.1.15 The failure of Contractor to provide and maintain in full force and effect any Contractor Parent Guaranty as required pursuant to Section 11.8, PARENT GUARANTY, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES and, in the event that a Credit Trigger Event has occurred after the Final Acceptance Date, the failure of Contractor to provide and maintain a Letter of Credit (or such other collateral permitted pursuant to such Section 11.8) in the face amount required in accordance with paragraph 3 of Appendix E – Credit Trigger Event;

15.1.16 Any failure by Contractor to maintain the insurance coverages required of it in accordance with Article IX, INSURANCE;

15.1.17 Any failure of Contractor to maintain the Letter of Credit in accordance with Section 7.5, LETTERS OF CREDIT, of Article VII, CONTRACT PRICE; PAYMENTS TO CONTRACTOR, including but not limited to any adjustment in the stated amount thereof (or posting of additional collateral permitted pursuant to such Section 7.5) upon the occurrence of a Credit Trigger Event; unless the available amount thereunder (as such available amount may be increased upon the occurrence of a Credit Trigger Event) has been drawn in full in accordance with the terms thereof;

15.1.18 Any abandonment of the Work by Contractor, where "Abandonment" for the purposes of this Section shall mean that Contractor has substantially reduced personnel at the Job Site or removed required equipment from the Job Site such that, in the opinion of an experienced construction manager, Contractor would not be capable of completing the Critical Milestones in accordance with the Project Schedule; or

15.1.19 The occurrence of a Credit Event of Default.

15.2 TERMINATION BY FPL DUE TO CONTRACTOR DEFAULT; OTHER REMEDIES.

15.2.1 Upon the occurrence of a Contractor Event of Default, FPL may, at its option, terminate this Agreement, without prejudice to any other rights and remedies available to FPL under this Agreement, by giving written notice thereof to Contractor, which termination shall be effective upon the giving of such notice by FPL.

15.2.2 In the event of a termination by FPL under this Section 15.2, FPL shall have the right to take possession of and use all of the Contractor Equipment located at the Job Site on the date of such termination for the purpose of completing the Work and may employ any other Person to complete the Work by whatever method that FPL may deem necessary. In addition, FPL may make such expenditures as in FPL's sole judgment will accomplish the timely completion of the Work in accordance with the terms hereof.

15.2.3 In the event of termination by FPL under this Section 15.2, Contractor shall not be entitled to receive any further payments under the Contract Documents (other than undisputed payments owed and payable to Contractor hereunder prior to the date of such termination).

15.2.4 In the event of termination by FPL under this Section 15.2, Contractor shall be responsible for and shall reimburse FPL for the following amounts:

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(a) All reasonable costs and expenses incurred by FPL to engage a substitute contractor to complete (or cure deficiencies in) the Work, including, without limitation, overhead and legal, engineering and other professional expenses;

(b) All reasonable costs and expenses incurred in connection with the termination of the Contract Documents, including costs and expenses incurred in connection with the obligations set forth under Section 15.9, OBLIGATIONS UPON TERMINATION;

(c) The amount by which:

(i) The cost reasonable to complete (or cure deficiencies in) the Work, exceeds

(ii) The balance of the Contract Price unpaid at the time of the termination; and

(d) All actual damages occasioned by reason of said default, except that Parties agree that Schedule Liquidated Damages shall apply in lieu of delay damages for late completion.

15.2.5 Upon the occurrence and during the continuance of a Contractor Event of Default but prior to termination of this Agreement by FPL, FPL may, without prejudice to any of its other rights or remedies:

(a) Seek performance by any guarantor of Contractor's obligations hereunder;

(b) Seek equitable relief to cause Contractor to take action or to refrain from taking action pursuant to this Agreement, or to make restitution of amounts improperly received under this Agreement;

(c) Make such payments or perform such obligations as are required to cure such Contractor Event of Default, and then draw on or make a claim against the Letter of Credit or other security provided pursuant to this Agreement for the cost of such payment or performance and/or offset the cost of such payment or performance against payments otherwise due to Contractor under this Agreement; provided that FPL shall be under no obligation to cure any such Contractor Event of Default;

(d) Seek damages as provided in Section 15.2.4, including proceeding against any bond, guarantee, letter of credit, or other security given by or for the benefit of Contractor for its performance under this Agreement;

(e) Require direct payment or co-payment to Subcontractors or Vendors and any such payments or co-payments shall be credited against amounts due to Contractor under the Agreement; or

(f) Assign to FPL any agreement or purchase order with a Subcontractor or Vendor, provided that:

(i) FPL shall assume the obligations under such agreement or purchase order accruing after the date of such assignment;

(ii) If requested by FPL, Contractor shall remain responsible for administering and managing such agreement or purchase order (including enforcing the warranty obligations thereunder); and

(iii) In no event shall Contractor be relieved of its obligation to achieve Provisional Acceptance or Final Acceptance as a result of such assignment.

15.3 TERMINATION BY FPL FOR CONVENIENCE.

15.3.1 FPL may terminate this Agreement at any time for any reason in its sole discretion by giving written notice thereof to Contractor, which termination shall be effective upon the giving of such notice by FPL. Upon receiving any such notice of termination, Contractor shall stop performing the Work and, except as otherwise directed by FPL, shall cancel as quickly as possible all orders placed by it with Subcontractors and Vendors and shall use all reasonable efforts to minimize cancellation charges and other costs and expenses associated with the termination of the Agreement. Contractor shall also promptly assign all subcontracts and purchase orders which FPL wishes to retain in accordance with Section 15.9, OBLIGATIONS UPON TERMINATION.

15.3.2 In the event of a termination by FPL under Section 15.3.1, Contractor shall be entitled to receive, as its sole and exclusive remedy for such termination, a termination payment ("Termination Payment") equal to the termination amount as set forth in the Termination Payment Schedule.

15.3.3 Intentionally Deleted.

15.3.4 In addition to FPL's right to terminate set forth in Section 15.3.1 above, FPL may terminate this Agreement because any of the following occurs pursuant to the Power Plant Siting Act, § 403.501-518, Florida Statutes and/or Chapter 62-17, Part I, (§ 62-17.011-62-17.293) of the Florida Administrative Code, the procedural rule implementing the act or otherwise:

(a) FPL does not select the Project pursuant to the "Request for Proposals";

(b) The Siting Board does not issue a "Land Use Order" for the Project;

(c) The Siting Board does not issue a "Final Certification Order";

(d) The Florida Department of Environmental Protection does not issue the "Air Construction Permit";

(e) The State of Florida Public Service Commission does not issue a "Need Order" for the Project;

(f) The Project is unable to obtain the applicable local, county, state or federal permits not covered by the Power Plant Siting Act;

(g) The administrative law judge responsible for recommending the Project to the Governor fails to recommend the Project;

(h) The Governor fails to approve the Project;

(i) Any other Government Authority whose approval or recommendation is necessary for the Project to be constructed fails to grant such approval or give such recommendation; or

(j) As a condition of obtaining any of the foregoing approvals or recommendations, FPL is required to materially amend the proposal for the Project (as determined in FPL's sole discretion);

then Contractor shall not be entitled to receive any further payments under the Contract Documents, except for the applicable Termination Payment.

15.3.5 Any amount owed pursuant to this Section 15.3, shall be subject to adjustment to the extent any Work contains Defects.

15.4 SUSPENSION BY FPL FOR CONVENIENCE.

15.4.1 FPL may suspend all or a portion of the Work to be performed under the Contract Documents at any time for any reason in its sole discretion by giving written notice thereof to Contractor. Such suspension, not to exceed 90 days individually and 180 days total while this Agreement is in effect, shall continue for the period specified in the notice of suspension; provided that Contractor agrees to resume performance of the Work promptly upon receipt of notice from FPL. Upon receiving any such notice of suspension, unless the notice requires otherwise, Contractor shall:

(a) Immediately discontinue the Work on the date and to the extent specified in the notice;

(b) Place no further orders or subcontracts for Equipment, services or facilities with respect to suspended Work, other than to the extent required in the notice;

(c) Promptly make every reasonable effort to obtain suspension, with terms reasonably satisfactory to FPL, of all orders, subcontracts and rental agreements to the extent they relate to performance of suspended Work;

(d) Continue to protect and maintain the Work performed, including those portions on which Work has been suspended; and

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(e) Take any other reasonable steps to minimize costs and expenses associated with such suspension.

15.4.2 Except as provided in Section 15.4.3, below, as full compensation for any suspension under this Section, Contractor will be reimbursed by FPL for the costs, as reasonably incurred, without duplication of any item, to the extent that such costs directly result from such suspension of the Work and to the extent that they do not reflect reimbursement for Contractor's, Vendors' or Subcontractors' anticipated profit from unperformed Work, including all necessary and reasonable costs incurred in connection with demobilization and remobilization of Contractor's facility and Labor and Contractor Equipment, plus an amount equal to 15% of such amounts.

15.4.3 Upon delivery of notice by FPL to Contractor to resume suspended Work, Contractor shall, as promptly as reasonably possible, resume performance under the Contract Documents to the extent required in the notice. Contractor may request a Change Order as a result of a suspension of Work under this Section within fourteen (14) days after receipt of notice to resume the suspended Work; provided that such suspension was not due to Contractor's negligence, willful misconduct or noncompliance with the terms of this Agreement. Contractor shall submit to FPL a request for Changes in accordance with Article VI, CHANGE ORDERS, and such request shall be accompanied by sufficient documentation setting forth the schedule impact and monetary extent of such claim in sufficient detail to permit thorough analysis by FPL; provided that if such information is not available within such fourteen (14) day period, Contractor shall notify FPL of such within such fourteen (14) day period and provide an expected date (which shall be as soon as reasonably practicable) for providing such information. If Contractor does not submit a request for Changes within such fourteen (14) day period and provide the information regarding schedule and monetary impact as required above within such fourteen (14) day period (or by the expected date if not possible during such fourteen (14) day period), Contractor shall not be entitled to any additional consideration or other amendments hereto and shall be deemed to have waived all claims and offsets against FPL as a result of the suspension of Work. Contractor shall permit access by FPL to pertinent records for purposes of reviewing the claims by Contractor of schedule and monetary impact.

15.4.4 Contractor shall not have any recourse to the provisions of Sections 15.4.2 or 15.4.3 if and to the extent that any suspension by FPL under this Section 15.4.1 occurs contemporaneously with any Force Majeure Event, FPL Caused Delay or a breach of Contractor's obligations under this Agreement.

15.5 [INTENTIONALLY DELETED]

15.6 FPL EVENTS OF DEFAULT

The occurrence and continuation of any of the following events shall constitute an event of default by FPL (each, an "FPL Event of Default"):

15.6.1 A failure by FPL to make payment of any undisputed amount when due, and such breach is not cured by FPL within fifteen (15) days after FPL's receipt of notice thereof from Contractor; or

15.6.2 Any breach by FPL of any representation or warranty made by FPL in Article XIII, REPRESENTATIONS;

15.6.3 Any of the following occurs:

(a) FPL consents to the appointment of or taking possession by, a receiver, a trustee, custodian, or liquidator of itself or of a substantial part of its assets, or fails or admits in writing its inability to pay its debts generally as they become due, or makes a general assignment for the benefit of creditors;

(b) FPL files a voluntary petition in bankruptcy or a voluntary petition or an answer seeking reorganization in a proceeding under any applicable bankruptcy or insolvency laws or an answer admitting the material allegations of a petition filed against it in any such proceeding, or seeks relief by voluntary petition, answer or consent, under the provisions of any now existing or future bankruptcy, insolvency or other similar law providing for the liquidation, reorganization, or winding up of corporations, or providing for an agreement, composition, extension, or adjustment with its creditors;

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(c) A substantial part of FPL's assets is subject to the appointment of a receiver, trustee, liquidator, or custodian by court order and such order shall remain in effect for more than thirty (30) days; or

(d) FPL is adjudged bankrupt or insolvent, has any property sequestered by court order and such order shall remain in effect for more than thirty (30) days, or has filed against it a petition under any bankruptcy, reorganization, arrangement, insolvency, readjustment of debt, dissolution or liquidation law of any jurisdiction, whether now or hereafter in effect, and such petition shall not be dismissed within thirty (30) days of such filing.

15.6.4 Any breach by FPL of any obligation, covenant or agreement of FPL hereunder other than those breaches specified in this Section 15.6, and:

(a) Such breach is not cured by FPL within fifteen (15) days after notice thereof from Contractor; or

(b) If such breach is not capable of being cured within such fifteen (15) day period (as determined by Contractor in its sole discretion), FPL fails to:

(i) Commence to cure such breach within such fifteen (15) day period;

(ii) Thereafter diligently proceed to cure such breach in a manner satisfactory to Contractor in its sole discretion; or

(iii) Cure such breach within ninety (90) days after notice thereof from Contractor.

15.6.5 The dissolution of FPL, except for the purpose of merger, consolidation or reorganization where the successor expressly assumes FPL's obligations hereunder and such assignment and assumption does not materially adversely affect the ability of the successor to perform its obligations under the Contract Documents.

15.6.6 The transfer by FPL of all or a substantial portion of the:

(a) Rights and/or obligations of FPL hereunder, except for an assignment permitted hereunder; or

(b) Assets or obligations of FPL, except where the transferee expressly assumes the transferred obligations and such transfer does not materially adversely affect the ability of FPL or the transferee, as applicable, to perform its obligations under the Contract Documents, as determined by Contractor in its sole discretion;

15.6.7 Any failure by FPL to maintain the insurance coverages required of it in accordance with Article IX, INSURANCE;

15.7 TERMINATION BY CONTRACTOR DUE TO FPL DEFAULT.

15.7.1 Subject to Section 15.7.2, below, upon the occurrence and during the continuance of an FPL Event of Default beyond the applicable grace period, Contractor may terminate this Agreement thirty (30) Days after giving written notice thereof to FPL so long as the amount owed by FPL (other than any amount disputed in accordance with the terms of this Agreement) is not paid within such period.

15.7.2 In the event of such termination, Contractor shall be entitled to receive an amount equal to the Termination Payment as its sole and exclusive remedy for such termination.

15.8 CONTINUING OBLIGATIONS AND REMEDIES DURING EVENT OF DEFAULT

In the event of the occurrence of any default hereunder:

15.8.1 Neither Party shall be relieved of any of its liabilities or obligations hereunder, unless and until such liabilities and obligations are terminated in accordance with the provisions hereof; and

15.8.2 Each Party shall have the right to pursue any right or remedy available to it, hereunder.

15.9 OBLIGATIONS UPON TERMINATION

Upon a termination of this Agreement pursuant to Section 15.2:

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15.9.1 Contractor shall leave the Job Site and remove from the Job Site all Contractor Equipment, waste, rubbish and Hazardous Material as FPL may request;

15.9.2 FPL shall take possession of the Job Site and of the Equipment (whether at the Job Site, in transit or otherwise);

15.9.3 Contractor shall promptly assign to FPL or its designee any contract rights (including warranties, licenses, patents and copyrights) that it has to any and all Equipment and the Work, including, without limitation, contracts with Subcontractors and Vendors, and Contractor shall execute such documents as may be reasonably requested by FPL to evidence such assignment, subject to FPL's assumption of same and, if required, FPL's adequate assurance to such Subcontractors or Vendors regarding FPL's ability to pay;

15.9.4 Contractor shall promptly furnish FPL with copies of all Drawings and, to the extent available, Final Plans, and copies of all computer files containing Drawings or Final Plans;

15.9.5 Contractor hereby grants FPL and its designee with the right to use, free of charge, all patented, copyrighted and other proprietary information relating to the Work that FPL deems necessary to complete the Work, and Contractor shall execute such documents as may be reasonably requested by FPL to evidence such right;

15.9.6 Contractor shall assist FPL in preparing an inventory of all Equipment in use or in storage at the Job Site;

15.9.7 Contractor shall perform all Remediation Work requested by FPL; and

15.9.8 Contractor shall take such other action as required hereunder upon termination of this Agreement.

15.10 TERMINATION AND SURVIVAL OF TERMS

Upon termination of this Agreement pursuant to this Article, the rights and obligations of the Parties hereunder shall terminate, except for the rights and obligations:

15.10.1 Accrued as of the date of termination;

15.10.2 Arising out of events occurring prior to the date of termination; and

15.10.3 Of the Parties which survive termination, including the rights and obligations forth in Articles XII, CONTRACTOR'S WARRANTIES, and XIII, REPRESENTATIONS.

ARTICLE XVI.
INDEMNIFICATION

16.1 CONTRACTOR INDEMNIFICATION

Contractor agrees to reimburse, indemnify, defend and hold FPL, the Financing Parties and their Affiliates and each of their respective directors, officers, employees, representatives, agents, advisors, consultants, counsel and assigns harmless from and against, on an After-Tax Basis, any and all losses, claims, obligations, demands, assessments, penalties, liabilities, costs, damages and expenses (including reasonable attorneys' fees and expenses) (collectively, "Damages") asserted against or incurred by such indemnitees by reason of or resulting from any and all of the following:

16.1.1 Any bodily injury, death or damage to property caused by any act or omission (including strict liability) or willful misconduct relating to or arising out of the performance of the Work or any curative action under any warranty following performance of the Work, of Contractor or any Affiliate thereof, any Subcontractor or Vendor, or anyone directly or indirectly employed by any of them, or anyone for whose acts such Person may be liable;

16.1.2 Any third party claims resulting in bodily or property damage arising out of defective and/or nonconforming Work relating to or arising out of the performance of the Work;

16.1.3 Claims by any Government Authority for any Contractor Taxes;

16.1.4 Any pollution or contamination which originates from sources in Contractor's or its Subcontractors' or Vendors' possession, use or control or caused by the release by Contractor or its Subcontractors or Vendors

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(excluding Pre-Existing Hazardous Material other than as provided in (e) below), including, without limitation, from Hazardous Material, toxic waste, industrial hazards, sanitary waste, fuel, lubricant, motor oil, paint, solvent, bilge and garbage;

16.1.5 Any release or exacerbation of Pre-Existing Hazardous Materials or rendering removal or remediation of Pre-Existing Hazardous Materials more costly, which in any of such events is caused by any negligent act or omission of Contractor or any Affiliate thereof, any Subcontractor or Vendor, or anyone directly or indirectly employed by any of them, or anyone for whose acts such Person may be liable;

16.1.6 To the extent FPL has paid all undisputed amounts due pursuant to the Contract Documents, any Lien, as set forth in Section 3.25, CLAIMS AND LIENS FOR LABOR AND MATERIALS, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, on the Equipment, the Job Site or any fixtures or personal property included in the Work (whether or not any such Lien is valid or enforceable) created by, through or under, or as a result of any act or omission (or alleged act or omission) of, Contractor or any Subcontractor, Vendor or other Person providing labor or materials in connection with the Work;

16.1.7 Any claim, action or proceeding by any Person for unauthorized disclosure, use, infringement or misappropriation of any Intellectual Property Right arising from:

(a) Contractor's performance (or that of its Affiliates, Subcontractors or Vendors) under the Contract Documents, including, without limitation, the Work, Equipment, Drawings, Final Plans or other items and services provided by Contractor or any Subcontractor or Vendor hereunder;

(b) The use or ownership of any Contractor Deliverable;

(c) Any license granted hereunder; or

(d) The design, engineering, construction, use, operation or ownership of the Plant or any portion thereof;

(Without limiting the provisions of Section 12.3, PROPRIETARY RIGHTS, of Article XII, CONTRACTOR'S WARRANTIES, if FPL is enjoined from completing the Project or any part thereof, or from the use, operation or enjoyment of the Project or any part thereof, as a result of such claim or legal action or any litigation based thereon, Contractor shall promptly use its best efforts to have such injunction removed at no cost to FPL.)

16.1.8 Any vitiation of any insurance policy procured under Article IX, INSURANCE, as a result of Contractor's failure to comply with any of the requirements set forth in such policy or any other act by Contractor or any Subcontractor or Vendor;

16.1.9 Any failure of the Project, as designed, constructed or completed by Contractor, to comply with, or be capable of operating in compliance with, Applicable Laws or the conditions or provisions of Applicable Permits;

16.1.10 Any failure of Contractor to comply with Applicable Laws or the conditions or provisions of Applicable Permits; and

16.1.11 Any claims with respect to employer's liability or worker's compensation filed by any employee of Contractor or any of its Subcontractors or Vendors.

16.2 FPL INDEMNIFICATION

FPL agrees to reimburse, indemnify, defend and hold Contractor and its Affiliates and each of their respective directors, officers, employees, representatives, agents, advisors, consultants and counsel harmless from and against, on an After-Tax Basis, any and all Damages asserted against or incurred by such indemnitees by reason of or resulting from any and all of the following:

16.2.1 Any bodily injury, death or damage to property caused by (a) any act or omission (including strict liability) or willful misconduct of FPL or its agents or employees or others under FPL's direct control or (b) a breach by FPL of its obligations hereunder;

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16.2.2 Claims by any Government Authority for any FPL Taxes;

16.2.3 Any Pre-Existing Hazardous Material on the Property Site, except to the extent covered by Section 16.1.5, Contractor Release or Exacerbation; and

16.2.4 Any claims with respect to employer's liability or worker's compensation filed by any employee of FPL.

16.3 CONDITIONS OF INDEMNIFICATION

The respective rights and obligations of the Parties and the other indemnitees under this Article with respect to claims resulting from the assertion of liability by third parties shall be subject to the following terms and conditions:

16.3.1 *Notice of Proceedings*. Within fourteen (14) days (or such earlier time as might be required to avoid prejudicing the indemnifying Party's position) after receipt of notice of commencement of any legal action or of any claims against such indemnitee in respect of which indemnification will be sought, the Person claiming to be indemnified under the terms of this Section (the "Indemnified Person") shall give the Party from which indemnification is sought (the "Indemnifying Party") written notice thereof, together with a copy of such claim, process or other legal pleading. Failure of the Indemnified Person to give such notice will not reduce or relieve the Indemnifying Party of liability hereunder unless and to the extent that the Indemnifying Party was precluded from defending such claim, action, suit or proceeding as a result of the failure of the Indemnified Person to give such notice. In any event, the failure to so notify shall not relieve the Indemnifying Party from any liability that it may have to the Indemnified Person otherwise than under this Article.

16.3.2 *Conduct of Proceedings*. Each Party and each other indemnitee shall have the right, but not the obligation, to contest, defend and litigate any claim, action, suit or proceeding by any third party alleged or asserted against it arising out of any matter in respect of which it is entitled to be indemnified hereunder and the reasonable costs and expenses thereof (including reasonable attorneys' fees and expert witness fees) shall be subject to the said indemnity; provided that the indemnifying Party shall be entitled, at its option, to assume and control the defense of such claim, action, suit or proceeding at its expense upon its giving written notice thereof to the Indemnified Person. The Indemnified Person shall provide reasonable assistance to the Indemnifying Party, at the Indemnifying Party's expense, in connection with such claim, action, suit or proceeding. Upon such assumption, the Indemnifying Party shall reimburse the Indemnified Person for the reasonable costs and expenses previously incurred by it prior to the assumption of such defense by the Indemnifying Party. The Indemnifying Party shall keep the Indemnified Person informed as to the status and progress of such claim, action, suit or proceeding. Except as set forth in paragraph (c) below, in the event the Indemnifying Party assumes the control of the defense, the Indemnifying Party will not be liable to the Indemnified Person under this Article for any legal fees or expenses subsequently incurred by the Indemnified Person in connection with such defense. The Indemnifying Party shall control the settlement of all claims over which it has assumed the defense; provided, however, that the Indemnifying Party shall not agree to or conclude any settlement that affects the Indemnified Person without the prior written approval of the Indemnified Person, (whose said approval shall not be unreasonably withheld).

16.3.3 *Representation*. In the event the Indemnifying Party assumes control of the defense, the Indemnified Person shall have the right to employ its own counsel and such counsel may participate in such claim, action, suit or proceeding, but the fees and expenses of such counsel shall be at the expense of such Indemnified Person, when and as incurred, unless the:

(a) Employment of counsel by such Indemnified Person has been authorized in writing by the Indemnifying Party;

(b) Indemnified Person shall have reasonably concluded that there may be a conflict of interest between the Indemnifying Party and the Indemnified Person in the conduct of the defense of such action; or

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(c) Indemnified Person shall have reasonably concluded and specifically notified the Indemnifying Party either that there may be specific defense available to it which are different from or additional to those available to the Indemnifying Party.

If any of the preceding clauses (a) through (c) shall be applicable, then counsel for the Indemnified Person shall have the right to direct the defense of such claim, action, suit or proceeding on behalf of the Indemnified Person and the reasonable fees and expenses of such counsel shall be reimbursed by the Indemnifying Party.

16.4 CONTRIBUTORY NEGLIGENCE

Except as provided in Section 16.2.2, above, if the joint, concurring, comparative or contributory fault, negligence or willful misconduct of the Parties gives rise to Damages for which a Party is entitled to indemnification under this Article, then such Damages shall be allocated between the Parties in proportion to their respective degrees of fault, negligence or willful misconduct contributing to such Damages.

16.5 REMEDIES NOT EXCLUSIVE

The rights under this Article shall not be exclusive with respect to any other right or remedy provided for in the Contract Documents.

16.6 PAYMENT

All payments required to be made under this Article shall be made on an After-Tax Basis and within thirty (30) days of demand therefor.

16.7 SURVIVAL OF INDEMNIFICATION

The provisions of this Article shall survive the Final Acceptance Date and the termination of this Agreement.

ARTICLE XVII.
DISPUTE RESOLUTION

17.1 FRIENDLY CONSULTATION

In the event of any dispute, controversy or claim between the Parties arising out of or relating to the Contract Documents, or the breach, termination or invalidity thereof (collectively, a "Dispute"), the Parties shall attempt in the first instance to resolve such Dispute through friendly consultations between the Parties. If such consultations do not result in a resolution of the Dispute within thirty (30) days after notice of a Dispute is delivered by either Party, then either Party may pursue all of its remedies available pursuant to the Contract Documents. The Parties agree to attempt to resolve all Disputes arising hereunder promptly, equitably and in a good faith manner. The Parties further agree to provide each other with reasonable access during normal business hours to any and all non-privileged records, information and data pertaining to such Dispute.

17.2 LITIGATION.

17.2.1 If a Dispute cannot be resolved pursuant to Section 17.1, FRIENDLY CONSULTATION, and in the event of litigation arising hereunder, the Parties agree that the venue for such litigation shall be the courts of the State of Florida in Miami-Dade County or Palm Beach County, Florida or the United States District Court for the Southern District of Florida, unless such other location or forum is mutually agreed. The Parties irrevocably waive any objection which any of them may now or hereafter have to the bringing of any such action or proceeding in such respective jurisdictions, including any objection to the laying of venue based on the grounds of forum non conveniens and any objection based on the grounds of lack of in personam jurisdiction. To facilitate the comprehensive resolution of related disputes, and upon the sole discretion and request of FPL, Contractor agrees and will stipulate in any proceeding to the consolidation of any litigation or other proceeding arising out of or relating to this Agreement with any other litigation or other proceeding arising out of or relating to any other agreement relating to the Project.

17.2.2 IN ANY LITIGATION ARISING FROM OR RELATED TO THE CONTRACT DOCUMENTS, THE PARTIES HERETO EACH HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE THE RIGHT EACH MAY HAVE TO A TRIAL BY JURY WITH RESPECT TO ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER OR IN CONNECTION WITH THE

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CONTRACT DOCUMENTS, OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF EITHER PARTY TO THE CONTRACT DOCUMENTS. THIS PROVISION IS A MATERIAL INDUCEMENT FOR FPL AND CONTRACTOR TO ENTER INTO THIS AGREEMENT.

17.2.3 The rights and obligations of the Parties under this Article shall not be impaired, reduced or otherwise affected as a result of any of the following the:

(a) Receipt by a Party from any third party of any amounts in reimbursement of Damages that are the subject of the Dispute; or

(b) Assignment or transfer by either Party of any or all of its rights and/or obligations under the Contract Documents as permitted hereunder.

17.2.4 In the event of any Dispute pursuant to this Article XVII, Dispute Resolution, the prevailing Party shall be entitled to recover its reasonable attorneys' fees and costs incurred in connection therewith.

17.3 CONTINUING OBLIGATIONS AND RIGHTS

When any Dispute occurs and is the subject of friendly consultations or litigation, Contractor shall continue the Work in accordance with the Project Schedule and the terms hereof and FPL shall continue to make payments of undisputed amounts in accordance with the Contract Documents, and the Parties shall otherwise continue to exercise their rights, and fulfill their respective obligations, under the Contract Documents.

17.4 TOLLING STATUTE OF LIMITATIONS

All applicable statutes of limitation and defenses based upon the passage of time and similar contractual limitations shall be tolled while the procedures specified in this Article are pending. The Parties will take such action, if any, required to effectuate such tolling. Without prejudice to the procedures specified in this Article, a Party may file a complaint for statute of limitations purposes, if in its sole judgment such action may be necessary to preserve its claims or defenses. Despite such action, the Parties will continue to participate in good faith in the procedures specified in this Article.

17.5 AUDIT RIGHTS

In the event of a claim by FPL under this Agreement involving an amount greater than Fifty Thousand Dollars ($50,000), Contractor shall grant audit rights to FPL with respect to all relevant documentation pertaining to such claim

ARTICLE XVIII.
MISCELLANEOUS

18.1 ASSIGNMENT.

18.1.1 Except as expressly permitted in the Contract Documents, Contractor may not assign this Agreement, the Contract Documents or any portion hereof, or any of the rights or obligations hereunder, without the prior written consent of FPL, which consent shall not be unreasonably delayed. This Agreement shall inure to the benefit of, and be binding upon, the successors and permitted assigns of the Parties.

18.1.2 FPL shall be entitled to assign this Agreement, the Contract Documents and its rights and obligations hereunder (a) to any Affiliate, without the consent of Contractor and (b) to any other Person, with the consent of Contractor, which consent shall not be unreasonably withheld or delayed, and Contractor shall release FPL from all obligations hereunder upon any such assignment; provided, however, that notwithstanding any assignment pursuant to clause (a) above, FPL shall remain responsible for all financial obligations under this Agreement. In addition, Contractor hereby consents to the granting of a security interest in and an assignment by FPL of the Contract Documents and its rights herein to the Financing

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Parties and their successors, assigns and designees. In furtherance of the foregoing, Contractor acknowledges that the Financing Parties may under certain circumstances assume the interests and rights of FPL under the Contract Documents.

18.1.3 Contractor acknowledges that the Financing Parties may under certain circumstances foreclose upon and sell, or cause FPL to sell or lease the Project and cause any new lessee or purchaser of the Plant to assume all of the interests, rights and obligations of FPL arising under the Contract Documents. In such event, Contractor agrees to the assignment by FPL and the Financing Parties of the Contract Documents and its rights herein to such purchaser or lessee and shall release FPL and the Financing Parties from all obligations hereunder upon any such assignment.

18.2 GOOD FAITH DEALINGS; AUTHORSHIP

The Parties undertake to act fairly and in good faith in relation to the performance and implementation of the Contract Documents and to take such other reasonable measures as may be necessary for the realization of its purposes and objectives. The Parties collectively have prepared the Contract Documents, and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of the Contract Documents or any part hereof.

18.3 CONFIDENTIALITY.

18.3.1 For purposes of this Agreement, "Confidential Information" shall mean:

(a) The contents of the Contract Documents;

(b) Any information relating to the negotiations or performance of the Contract Documents; and

(c) Any information provided pursuant to the Contract Documents relating to the Project, Plant, FPL, Contractor or their Affiliates which:

(i) The disclosing Party designates in writing as confidential, proprietary or the like and which is received by the other Party;

(ii) By its nature is such that the receiving Party should reasonably conclude that possession of such information is of material commercial or competitive value to the disclosing Party;

(iii) Relates to the configuration, operation, management processes or profitability of the Plant; or

(iv) Relates to Project partners or prospective Project partners of FPL, including the names thereof.

18.3.2 Information shall be Confidential Information for the purposes hereof regardless of:

(a) The form in which it is communicated or maintained (whether oral, written, electronic or visual);

(b) Whether of a business, financial, legal, technical, managerial or other nature; and

(c) Whether prepared by the disclosing Party or otherwise.

18.3.3 Each Party agrees to hold all Confidential Information in confidence and not disclose it other than to its Affiliates, contractors (or potential contractors), subcontractors, vendors, consultants, advisors, Financing Parties (or potential Financing Parties), employees, directors, officers, agents, advisors or representatives (collectively, the "Personnel") for purposes of the Project or to any purchaser of the Project or a direct or indirect interest in Owner. Each Party agrees that only Personnel who need to have access to Confidential Information in order to perform their duties will be authorized to receive the same, and then only to the extent needed and provided such Personnel have been advised of the obligations and restrictions set forth in this Section 18.3. Each Party shall be responsible for any breach of this Agreement by its Personnel.

18.3.4 Notwithstanding the foregoing, information shall not be deemed to be Confidential Information where it:

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(a) Is or becomes public information or otherwise generally available to the public through no act of or failure to act by the receiving Party;

(b) Was, prior to the date of this Agreement, already in the possession of the receiving Party and was not received by such Party directly or indirectly from the other Party;

(c) Is rightfully received by the receiving Party from a third party who is not prohibited from disclosing it to such Party and is not breaching any agreement by disclosing it to such Party;

(d) Is independently developed by the receiving Party without benefit of Confidential Information received from the other Party;

(e) Is the property of the Party disclosing such information;

(f) Is necessary or advisable for FPL to exercise its Intellectual Property Rights under this Agreement; or

(g) Is necessary or advisable to disclose such information for the purpose of enforcing or exercising the disclosing Party's rights hereunder.

Specific information shall not be deemed to be within the foregoing exceptions merely because it is embraced by more general information within such exceptions, nor shall a combination of features be deemed to be within such exceptions merely because the individual features are within such exceptions.

18.3.5 If a Party is required by Applicable Law or any Government Authority to disclose any Confidential Information, such Party shall promptly notify the other Party of such requirement prior to disclosure so that the other Party may seek an appropriate protective order and/or waive compliance with the terms of this Section 18.3. If such protective order or other remedy is not obtained, then such Party shall furnish only that portion of the Confidential Information which is legally required to be furnished by the Applicable Law or Government Authority; provided, however, that prior to making any such disclosure, such Party will:

(a) Minimize the amount of Confidential Information to be provided consistent with the interests of the other Party; and

(b) Make every reasonable effort (which shall include participation by the other Party in discussions with the Government Authority involved) to secure confidential treatment of the Confidential Information to be provided.

If efforts to secure confidential treatment are not successful, the other Party shall have the prior right to revise such information in a manner consonant with its interests and the requirements of the Government Authority involved.

18.3.6 Each Party acknowledges that the other Party would not have an adequate remedy at law for money damages if the covenants contained in this Section 18.3 were breached and that any such breach would cause the other Party irreparable harm. Accordingly, each Party also agrees that in the event of any breach or threatened breach of this Section 18.3 by such Party or its Personnel, the other Party, in addition to any other remedies it may have at law or in equity, shall be entitled, without the requirement of posting a bond or other security, to equitable relief, including injunctive relief and specific performance.

18.3.7 All right and title to, and interest in, FPL's Confidential Information shall remain with FPL. Subject to Section 3.32, all Confidential Information obtained, developed or created by or for Contractor exclusively for the Project, including copies thereof, is the exclusive property of FPL whether delivered to FPL or not. No right or license is granted to Contractor or any third party respecting the use of Confidential Information owned by FPL by virtue of this Agreement, except to the extent required for Contractor's performance of its obligations hereunder. Except for that Confidential Information which FPL requires to construct, operate, and/or maintain the Project and its power generation facilities, which Confidential Information shall not be subject to any obligation of return by FPL, at any time upon written request by a disclosing Party, the other Party shall promptly return to the disclosing Party all its Confidential Information,

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including all copies thereof, and shall promptly purge all electronic copies of such Confidential Information; provided that the other Party shall be entitled to keep one (1) copy of such Confidential Information for its legal records. The return of Confidential Information to the disclosing Party, the purging of electronic copies of Confidential Information or the retention of a copy of Confidential Information for legal records shall not release a Party from its obligations hereunder with respect to such Confidential Information.

18.3.8 Contractor shall coordinate with FPL with respect to, and provide advance copies to FPL for review of, the text of any proposed announcement or publication that include any non-public information concerning the Work prior to the dissemination thereof to the public or to any Person other than Subcontractors, Vendors, the Financing Parties or advisors of Contractor, in each case, who agree to keep such information confidential. If FPL delivers written notice to Contractor rejecting any such proposed announcement or publication within two (2) Business Days after receiving such advance copies, Contractor shall not make such public announcement or publication; provided, however, that Contractor may disseminate or release such information in response to requirements of Government Authorities.

18.4 NOTICE

18.4.1 Whenever a provision of the Contract Documents requires or permits any consent, approval, notice, request, or demand from one Party to another, the consent approval, notice, request, or demand must be in writing and delivered in accordance with this Section in order to be effective. Any such consent approval, notice, request or demand shall be delivered and received if:

(a) Personally delivered or if delivered by telegram or courier service, when actually received by the Party to whom notice is sent;

(b) Delivered by telex or facsimile, on the first Business Day following the day transmitted (with confirmation of receipt);

(c) Delivered by mail (whether actually received or not), at the close of business on the third Business Day following the day when placed in the mail, postage prepaid, certified or registered, addressed to the appropriate Party,

In each case, at the address and/or facsimile numbers of such Party set forth below (or at such other address as such Party may designate by written notice to the other Party in accordance with this Section):

(i) If to Contractor:

SunPower Corporation, Systems
1414 Harbour Way South
Richmond, California 94804
Attention: President
Fax: (510) 540-0552

With a copy to:

Latham & Watkins LLP
Sears Tower, Suite 5800
233 S. Wacker Drive
Chicago, IL 60606
Attention: Mark P. Ramsey
Fax: (312) 993-9767

(ii) If to FPL:

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Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida
Attention: E. N. Scoville II
Director – Construction
Fax: (561) 694-3960

With a copy to:

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida
Attention: General Counsel
Fax: (561) 691-7305

18.4.2 Any Party may change its address, facsimile number or e-mail number for the purposes of this Agreement by giving notice thereof to the other Party in the manner provided herein.

18.5 WAIVER

No delay, failure or refusal on the part of any Party to exercise or enforce any right under the Contract Documents shall impair such right or be construed as a waiver of such right or any obligation of another Party, nor shall any single or partial exercise of any right hereunder preclude other or further exercise of any right. The failure of a Party to give notice to the other Parties of a breach of the Contract Documents shall not constitute a waiver thereof. Any waiver of any obligation or right hereunder shall not constitute a waiver of any other obligation or right, then existing or arising in the future. Each Party shall have the right to waive any of the terms and conditions of the Contract Documents that are for its benefit. To be effective, a waiver of any obligation or right must be in writing and signed by the Party waiving such obligation or right.

18.6 SEVERABILITY

If any provision of the Contract Documents is held to be illegal, invalid, or unenforceable under present or future laws, such provision shall be fully severable; the Contract Documents shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part of the Contract Documents; and the remaining provisions of the Contract Documents shall remain in full force and effect and shall not be affected by the illegal, invalid, or unenforceable provision or by its severance from the Contract Documents. Furthermore, in lieu of such illegal, invalid or unenforceable provision, there shall be added automatically as a part of the Contract Documents a provision as similar in its terms to such illegal, invalid or unenforceable provision as may be possible and be legal, valid and enforceable.

18.7 GOVERNING LAW

The Contract Documents, and the rights and obligations of the Parties under or pursuant to the Contract Documents, shall be interpreted and construed according to the substantive laws of the State of Florida (regardless of any other jurisdiction's choice of law rules).

18.8 ENTIRE AGREEMENT; AMENDMENTS

The Contract Documents contain the entire understanding of the Parties with respect to the subject matter hereof and supersede all prior agreements, arrangements, discussions and undertakings between the Parties (whether written or oral) with respect to the subject matter hereof. The Contract Documents may only be amended by written instrument signed by all the Parties.

18.9 EXPENSES AND FURTHER ASSURANCES

Each Party shall pay its own costs and expenses in relation to the negotiation, preparation, execution and carrying into effect of the Contract Documents. Each Party shall, from time to time on being requested to do so by, and at the cost and expense of, the other Party, do all such acts and/or execute and deliver all such

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instruments and assurances as are reasonably necessary for carrying out or giving full effect to the terms of the Contract Documents.

18.10 NO THIRD PARTY BENEFICIARY

Except with respect to the rights of the Financing Parties, permitted successors and assigns and as provided above and the rights of indemnitees under Article XVI, INDEMNIFICATION:

18.10.1 Nothing in the Contract Documents nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any Person that is not a Party;

18.10.2 No person that is not a Party shall have any rights or interest, direct or indirect, in the Contract Documents or the services to be provided hereunder; and

18.10.3 The Contract Documents are intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to the Contract Documents or the services to be provided hereunder.

18.11 OFFSET

Notwithstanding any other provision hereof, any and all amounts owing or to be paid by FPL to Contractor hereunder or otherwise, shall be subject to offset and reduction in an amount equal to any amounts that may be owing at any time by Contractor to FPL. Further, for the avoidance of doubt, with respect to any provision of this Agreement that allows FPL to offset, set-off or draw against the Letter of Credit any amount then owed to Contractor, FPL shall have the express right to include in the amount offset, set-off or drawn under the Letter of Credit all of the reasonable costs and expenses it incurs in connection with enforcing such provision (including attorneys' and other consultants' fees).

18.12 COUNTERPARTS

This Agreement may be executed in multiple counterparts, each of which shall be deemed an original, and all of which together shall constitute one and the same instrument.

18.13 LIMITATIONS OF LIABILITY

18.13.1 Contractor's maximum liability under this Agreement shall be limited to (x) prior to the Provisional Acceptance Date, one hundred percent (100%) of the Contract Price and (y) after the Provisional Acceptance Date, 25% of the Contract Price, less the amount of Liquidated Damages previously paid by Contractor; provided, however, that such limitation of liability shall not apply to (i) Contractor's indemnification obligations under the Agreement related to claims of third parties; (ii) costs incurred by Contractor (and in the event of Contractor default, FPL) in achieving Provisional Acceptance and Final Acceptance (including the amount of any reduction in the Contract Price in the event that Contractor makes the election provided for in Section 10.5.1(b)); or (iii) any loss or damage arising out of any tort (including negligence and strict liability) or connected with Contractor's fraud, willful misconduct or illegal or unlawful acts. Contractor's limitations of liability shall not be reduced by the amount of insurance proceeds available to Contractor. FPL's maximum liability under this Agreement shall be limited to one hundred percent (100%) of the Contract Price prior to the Provisional Acceptance Date and 25% of the Contract Price after the Provisional Acceptance Date, except with respect to any payment due and payable pursuant to Section 7.1,Contract Price; provided however, that such limitation of liability shall not apply to any loss or damage arising out of any tort (including negligence and strict liability) or connected with FPL's fraud, willful misconduct or illegal or unlawful acts. FPL's limitations of liability shall not be reduced by the amount of insurance proceeds available to FPL.

18.13.2 Except as expressly set forth in this Agreement, and notwithstanding anything else in this Agreement to the contrary, Contractor and FPL waive claims against each other for any indirect, special or consequential damages arising out of or relating to this Agreement. This mutual waiver includes:

18.13.3 Damages incurred by FPL for rental expenses, for losses of use, income, profit, financing, business and reputation, and for loss of management or employee productivity, or the services of such persons;

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18.13.4 Damages incurred by Contractor for principal office expenses, including the compensation of personnel stationed there, for loss of financing, business and reputation, and for loss of profit except anticipated profit arising directly from the work; and

18.13.5 This mutual waiver is applicable, without limitation, to all consequential damages due to either Party's termination in accordance with Article XV, TERMINATION.

The foregoing waiver shall not preclude or limit recovery (i) of Schedule Liquidated Damages, (ii) of damages payable by Contractor to FPL pursuant to Section 15.2.4, Amounts Due FPL, of Article XV, TERMINATION, (iii) of the Termination Payment; or (iv) under any indemnity or reimbursement obligation hereunder related to claims of third parties.

18.14 TIME IS OF THE ESSENCE

Contractor acknowledges that timely achievement by Contractor of Mechanical Completion, Provisional Acceptance and Final Acceptance by the applicable scheduled date therefore is essential to FPL, and therefore TIME IS OF THE ESSENCE in performing all of Contractor's obligations set forth herein.

18.15 RECORDS RETENTION

Contractor agrees to retain for a period of five (5) years from the Final Acceptance Date all records relating to its performance of the Work or Contractor's warranty obligations herein, and to cause all Subcontractors and Vendors engaged in connection with the Work or the performance by Contractor of its warranty obligations herein to retain for the same period all their records relating to the Work.

18.16 SUCCESSORS AND ASSIGNS

Subject to Section 18.1, ASSIGNMENT, this Agreement shall be binding on the Parties hereto and on their respective successors and assigns.

18.17 FINANCING PARTIES' REQUIREMENTS

Contractor acknowledges that FPL may borrow certain funds from the Financing Parties for the construction of the Plant and that, as a condition to making loans to FPL, the Financing Parties may from time to time require certain documents from, and agreements by, Contractor and its Subcontractors and Vendors. In connection therewith, Contractor agrees to furnish to the Financing Parties, and to cause its Subcontractors and Vendors to furnish to the Financing Parties, such written information, certificates, copies of invoices and receipts, lien waivers (upon payment), affidavits, consents to assignment of the Contract Documents and other like documents as the Financing Parties may reasonably request. In addition, Contractor agrees to accept all revisions or amendments to the Contract Documents which are reasonably requested by the Financing Parties in order to facilitate Financial Closing, provided that such revisions or amendments are of a nature typically obtained by financing parties in non-recourse financing. Upon the request of the Financing Parties, as a condition precedent to Financial Closing, Contractor shall state in writing whether or not it is satisfied with FPL's performance to that date.

18.18 FINANCIAL ASSURANCES

18.18.1 In the event that there is a default under Section 15.1.19, then, in addition to any other remedies that FPL may have under this Agreement or otherwise, FPL may inform Contractor of such determination and Contractor shall have ten (10) Business Days after receipt of notice of such determination from FPL to meet with FPL's senior management and provide assurance reasonably acceptable to FPL that Contractor is capable of performing and completing the Work and its obligations under the Contract Documents.

18.18.2 In the event such assurance is not acceptable to FPL, as determined by FPL in its sole discretion, Contractor shall immediately as requested by FPL:

(a) Require direct payment or co-payment to Subcontractors and any such payments or co-payments shall be credited against amounts due to Contractor under the Agreement;

(b) Adjust the amount of Work to be performed by Contractor and in good faith negotiate corresponding adjustments in the Contract Price and, if applicable, Critical Milestones; and/or

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(c) Assign to FPL any agreement or purchase order with a Subcontractor or Vendor, provided that:

(i) FPL shall assume the obligations under such agreement or purchase order accruing after the date of such assignment;

(ii) If requested by FPL, Contractor shall remain responsible for administering and managing such agreement or purchase order (including enforcing the warranty obligations thereunder);

(iii) In no event shall Contractor be relieved of its obligations under this Agreement, including its obligation to achieve Provisional Acceptance or Final Acceptance as a result of such assignment; and

(iv) If Contractor remains responsible for administering and managing agreements or purchase orders pursuant to subparagraph (ii) above, then in no event shall Contractor be entitled to an FPL Caused Delay, Force Majeure Event or other relief in connection with any matter or claim arising out of or in any way related to FPL exercising its rights pursuant to this Section 18.18.

18.19 WAIVER OF CLAIMS.

18.19.1 In the event that this Agreement is terminated by FPL in accordance with its terms, and FPL subsequently signs an agreement to complete the Work (or any portion thereof) with any Person, then Contractor shall and shall cause its Affiliates, including Contractor Parent Company, to waive the right to make any claims (other than claims by Contractor with respect to amounts specifically provided herein to be paid to Contractor in the event of a termination hereunder) against FPL or any Person with whom FPL negotiates or executes an agreement for completion of any portion of the Work based upon:

(a) Such termination;

(b) Any subsequent negotiations with any Person; and

(c) Execution of such agreement and performance thereunder.

Such waiver includes, without limitation, a waiver of any claims against FPL and any Person with whom FPL negotiates or executes an agreement for completion of any portion of the Work, for tortious interference with business relationships.

18.19.2 Contractor agrees to reimburse, indemnify, defend and hold FPL, the Financing Parties and their Affiliates and each of their respective directors, officers, employees, representatives, agents, advisors, consultants, counsel and assigns harmless from and against, on an After-Tax Basis, any and all losses, claims, obligations, demands, assessments, penalties, liabilities, costs, damages and expenses (including attorneys' fees and expenses) for any claim made by Contractor or any of the above entities pursuant to paragraphs (a), (b) or (c) of Section 18.19.1, above. Contractor expressly agrees that any Person with whom FPL negotiates or executes an agreement for completion of any portion of the Work is an express third party beneficiary of this Section.

18.20 ACCEPTANCE OR REJECTION IN BANKRUPTCY.

18.20.1 Notwithstanding anything contained in this Agreement to the contrary, if an order for relief under Chapter 11 of the Bankruptcy Code is entered with respect to Contractor during the term of the Agreement, then Contractor acknowledges and agrees that it will, subject to Bankruptcy Court approval, formally assume or reject, subject to the requirements of 11 U.S.C. §365, the Agreement within seven (7) days of delivery of written request for such action by FPL. If Contractor fails to timely move for approval or rejection of the Agreement, it acknowledges and agrees that:

(a) It will not contest or in any way otherwise take any action to oppose such a motion filed by FPL or the lifting of the automatic stay of 11 U.S.C§362 to permit FPL to enforce its rights under the Agreement (the "Lift Stay Order");

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(b) It waives all rights it may have under 11 U.S.C. §362(f);

(c) It hereby consents to the ex parte entry of the Lift Stay Order pursuant to 11 U.S.C. §362(f); and

(d) At the option of FPL, it hereby agrees that it will execute an agreed Lift Stay Order on forty-eight (48) hours' notice.

18.20.2 Contractor acknowledges and represents to FPL and agrees that:

(a) It is familiar with the Agreement and the importance of completing its obligations under the Agreement on time and in accordance with its terms; and

(b) Based upon such familiarity, it is critical to performance of its obligations under the Agreement that FPL have prompt and immediate access (in accordance with the requirements of this Agreement) to its contractual remedies under the Agreement in the event of a Contractor Event of Default.

18.21 CONTRACTOR'S LICENSE

Contractor hereby states and FPL acknowledges that Contractor does not presently hold a license as a qualified business entity under Fla. Stat. Chapter 489 (a "Florida Contractor's License"), but that an application for such qualification has been submitted to the Florida Department of Business and Professional Regulation for processing. FPL further acknowledges its full knowledge of Contractor's failure to have a Florida Contractor's License status and hereby agrees that FPL shall not challenge the enforceability of this Agreement based on Contractor's failure to have a Contractor's License as of the date of the execution of this Agreement. In order to satisfy the requirements of this Agreement, Contractor hereby covenants, warrants and agrees that it shall receive all proper licenses required to perform the work more particularly described herein prior to beginning physical work on the Project, including but not limited to a Florida Contractor's License.

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IN WITNESS WHEREOF the Parties have executed and delivered this Agreement as of the date first above written.

SUNPOWER CORPORATION, SYSTEMS		FLORIDA POWER & LIGHT COMPANY	
BY:		BY:	
NAME:	HOWARD WENGER	NAME:	WILLIAM YEAGER
TITLE:	EXECUTIVE VICE PRESIDENT	TITLE:	VP T&C
DATE:	3. JULY. 2008	DATE:	7/3/08

HEARING EXHIBIT - 00000104

DESOTO.

Appendix A – Scope of Work

HEARING EXHIBIT - 00000105

Appendix A
SCOPE OF WORK

ENGINEER, PROCURE AND CONSTRUCT
FPL PV PROJECTS

REV. 3

SECTION	REVISION

ECRC-08-2936
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ENGINEER, PROCURE AND CONSTRUCT
FPL PV PROJECTS

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Appendix A
SCOPE OF WORK

1.0 PROJECT DESCRIPTION

1.1 This project consists of the installation of the following ground mounted, single axis tracking, photovoltaic (PV) power generation systems:

1.1.1 A 25 MW (net) photovoltaic power generation system to be located in Desoto County, FL. This installation will be connected to FPL's transmission system.

2.0 SCOPE OF WORK

2.1 Work by Contractor

2.1.1 The Work to be provided by Contractor shall include all work (except for those items specifically excluded) required to deliver a PV system ("Plant") capable of operating in accordance with the attached performance specifications, laws and permits, and in accordance with the project milestone schedule. Contractor's scope of work shall include, but shall not necessarily be limited to, the engineering, design, supply, delivery, installation, construction, training, start-up, and testing, as necessary to deliver the commercially operational Plant. Contractor shall design and construct the Project in accordance with this Appendix A, Scope of Work, and all of the Exhibits attached hereto. The following equipment, material and services shall be provided:

2.1.2 Structural systems as necessary to support photovoltaic panels, inverters, switchgear, circuit breakers, protective relaying equipment, control systems, transformers, enclosures, and other components.

2.1.3 Electric systems for all Plant services including power wiring, switchgear, duct banks, cable trays, conduit, circuit breakers, disconnect switches, inverters, instruments, transformers, protective relaying, lighting, and other components as required.

2.1.4 Instrumentation, controls, interconnecting control wiring, panels, cable tray and/or conduits required for the complete individual equipment and system controls.

2.1.5 Lighting fixtures, lighting panels, convenience receptacles, wiring, raceways and other components required for a complete lighting system, including site access and site area lighting.

2.1.6 Grounding rods and other components for a complete grounding system and lightning protection system.

2.1.7 A condition monitoring system for local and remote monitoring. Remote monitoring shall be capable of connecting to the Internet for web-enabled data monitoring.

2.1.8 AC kWh meter cabinets for FPL provided primary and backup revenue meters.

2.1.9 Site meteorological station(s) as required to obtain data to determine system performance.

2.1.10 All required equipment tests and inspections.

2.1.11 Engineering and technical support services for permits and licenses that require Contractor provided design and information. Contractor shall use best efforts in supplying support for all FPL licensing and approval requirements.

2.1.12 Site Security during construction and commissioning. Permanent site security system including perimeter fencing, and four (4) manual gates.

2.1.13 Construction consumables through Provisional Acceptance. Consumables will include but not be limited to chemicals, fuses, and other supplies. Contractor will also supply all necessary electrical power and water required for construction.

2.1.14 Delivery, unloading, and storage of all Contractor supplied equipment.

2.1.15 Operating tests to demonstrate guaranteed performance.

2.1.16 All calculations necessary for proper sizing of electrical and mechanical equipment and systems to insure safe and reliable plant operation under all plant operating modes.

2.1.17 Contractor shall comply with all permit requirements. Contractor shall develop an environmental control program that incorporates all permit and Exhibit A

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(Environmental Rules for Contractors) requirements for the construction and startup activities at the Job Site.

2.1.18 Contractors shall have a safety program for the site that incorporates all OSHA and Appendix X (Safe and Secure Workplace Policy) requirements.

2.1.19 Temporary facilities for FPL's site staff during construction and commissioning. For bid purposes assume space is required for 4 people.

2.1.20 Deleted.

2.1.21 Installation of FPL provided metering transformers and the supply and installation of conduits from the metering transformers to the meter cabinet. FPL shall provide the revenue metering cables.

2.2 Work by FPL

2.2.1 FPL will provide a permitted, cleared, and level graded site.

2.2.1.1 Site development and preparation includes access roads, grubbing, clearing, site leveling, site landscaping and soil stabilization. The maximum change in elevation shall be 7% in any direction.

2.2.2 Utility grade AC kWh meters will be supplied and installed by FPL. Primary and backup meters will be provided.

2.2.3 FPL will prepare and submit the Small Generator Interconnection Request. The Interconnection Study will be provided to the Contractor within 30 days of the effective contract date.

2.3 Boundary and Interface Limits

2.3.1 All work provided by Contractor shall be within the site boundary limits.

2.3.1.1 The site boundary is detailed in Exhibit C (Site Boundary limit).

2.3.1.2 The site boundary existing conditions and proposed Sunshine Substation location is detailed in Exhibit D (Site Development Plan).

2.3.1.2.1. Existing conditions shown are for informational use only and not for construction.

2.3.1.2.2. The Sunshine Substation location and layout are for informational use only and not for construction.

2.3.1.3 Contractor shall connect into, interface or terminate at the connection to 23 kV FPL distribution.

2.3.1.4 The interface location to be the Contractor-provided switch cabinet from which the Plant output will leave the site boundary at distribution or transmission voltage. FPL to provide interconnection between the switch cabinet and FPL Sunshine Substation.

3.0 PLANT DESIGN CRITERIA

3.1 Site Location

3.1.1 The Plant will be situated in Desoto County, FL near Arcadia.

3.1.2 The plant location is 27.30°N, 81.70°W.

3.1.3 Design Data

3.1.3.1 Range of Ambient Conditions: The Plant shall be capable of continuous operation between the following extreme temperatures:

3.1.3.1.1. 104°F maximum ambient temperature.

3.1.3.1.2. 18°F minimum ambient temperature

3.1.3.2 Wind Load per Florida Building Code, 2004, effective July 1, 2005 as amended by Desoto County.

3.1.3.3 Seismic Load per Florida Building Code, 2004, effective July 1, 2005 as amended by Desoto County

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3.1.3.4 Precipitation:

3.1.3.4.1. Annual Average = 49.34"

3.1.3.4.2. Maximum Monthly Average = 7.81"

3.1.3.4.3. Minimum Monthly Average = 1.76"

3.1.3.4.4. One day maximum = 7.51"

3.1.3.5 Design Storm Events, 24 hour precipitation

3.1.3.5.1. 10 year (10% probability) – 8.0 "

3.1.3.5.2. 25 year (4% probability) – 9.0"

3.1.3.5.3. 110 year (1% probability) – 12.0"

Note 1: For storm water detention, retention, and evaporation pond facilities unless specific state or local regulations are more stringent.

Note 2: For site drainage facilities unless specific state or local regulations are more stringent.

Note 3: For site drainage system without causing damage to major plant facilities.

3.1.3.6 Freeze Protection: Freeze protection shall be provided for and limited to all instrumentation and instrument sensing lines.

3.2 Operational Criteria

3.2.1 The Plant shall be designed for fully automatic, unmanned operation. This shall include startup, shutdown, abnormal operating condition (i.e. voltage, frequency excursions) detection and shutdown, data monitoring, etc.

3.3 Plant Performance

3.3.1 Contractor shall design and construct the Plant to produce the specified net electrical AC power of 25 MW, based on Standard Test Conditions.

3.3.2 Contractor shall provide a recommended spare parts list, including the proposed pricing for spare parts within 30 days of the Contract effective date.

3.3.3 The Plant shall be designed to maximize the annual energy production.

3.4 General Requirements

3.4.1 The systems and equipment supplied by Contractor shall be suitable for the environment in which they will be located and shall be designed for a Plant life of at least thirty (30) years.

3.4.2 The specifications provided herein are intended to identify overall system requirements and certain specific hardware requirements, which FPL requires to ensure that the Plant provided by Contractor shall operate reliably and safely during the Plant's design life, and that the Plant shall be able to be operated and maintained in a cost-effective manner. The adequacy of the overall system design to meet these requirements is the responsibility of Contractor.

3.4.3 The general system performance criteria are defined in this Technical Specification and the Exhibits. Contractor is responsible for ensuring that all system performance criteria included in this specification are met by the final Plant design.

3.5 Reliability and Maintainability

3.5.1 The design philosophy used to attain high reliability and maintainability shall be consistent with industry standards including:

3.5.1.1 Design margins and de-rating factors in sizing equipment to account for wear, performance degradation, voltage drops, and other conditions. Performance guarantees, however, shall be based on the new and clean condition.

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3.5.1.2 Provisions to isolate and bypass equipment for repair where feasible without shutdown of the system of which it is a part, such as repairing a component with minimized need to shut down surrounding components.

3.5.1.3 Access provisions for maintenance of equipment items known to require frequent service, such as inverters. Stairs shall be provided to elevated locations when access is required on a daily or frequent basis.

3.5.1.4 Access and removal provisions for all equipment parts from Plant using conventional maintenance equipment.

3.5.1.5 Compliance with manufacturer requirements for pull space and recommendations for laydown/storage areas.

3.5.2 Contractor shall provide as part of the equipment operations and maintenance manual, the typical daily, monthly, and annual maintenance activities expected for the Plant. This shall include inspection and testing activities, preventative/periodic maintenance activities, and recommended equipment replacement intervals for the Plant.

3.6 Noise

3.6.1 The Plant shall meet all applicable Federal, State, and local noise requirements.

3.6.2 The near-field A-weighted sound pressure level resulting from each balance-of-plant individual equipment package shall not exceed a spatial average of 85 dBA at a distance of three (3) feet from the equipment face and five (5) feet above the ground and personnel platforms unless approved by FPL. Contractor shall evaluate near field noise level on an individual equipment basis as certain Plant equipment is inherently noisy and special noise control measures may be necessary to comply with the 85-dBA criteria. For certain equipment, these noise control measures are not practical for reasons of performance, cost, maintenance access, heat buildup, space limitations, safety, etc. Therefore, if it is not reasonable and feasible to meet the 85-dBA criteria, administrative controls shall be implemented. Administrative controls include posting warning signs, prescribing hearing protection, and limiting access to ensure worker noise exposure does not exceed a 90 dBA average over an eight (8) hour period. The intent of this requirement is to control occupational noise exposure levels, protect worker hearing, and improve working conditions. The noise levels must conform to Occupational Safety and Health Act and all applicable State and local requirements.

3.6.3 In the design and layout of equipment, Contractor shall endeavor to attain permissible noise exposure levels, without the use of hearing protection. In areas where this is not practical, as discussed in Section 3.7.2, above, Contractor shall conduct an in-plant noise survey to identify the in-plant areas that are exposed to A-weighted sound pressure levels exceeding 85 dBA. Contractor shall designate areas over 85 dBA as high noise level areas with signs in the Plant, and shall indicate boundaries on the as-built general arrangement drawings for the mandatory wearing of hearing protection.

3.7 Miscellaneous Technical Requirements

3.7.1.1 Long-term operability, maintainability and safe operation of the Plant is of primary concern to FPL. As a result, Contractor shall take prudent measures in the design to facilitate ease of operation and maintenance and provide adequate access to all equipment.

3.8 Codes, Regulations and Standards

3.8.1.1 Contractor shall design and construct the Plant in accordance with all federal, state and local laws and the codes, regulations and standards listed below. The codes and standards utilized shall be the latest editions in effect on the effective date of this Contract. Where these codes do not govern specific features of the equipment or system, Contractor and Original Equipment Manufacturer (OEM) standards shall be applied. Where local codes or ordinances will have an impact on the design (e.g. building height restrictions) FPL and Contractor shall jointly address these with the local authorities having jurisdiction.

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3.8.2 Federal Regulations

3.8.2.1 Federal Environmental Standards

3.8.2.1.1. US Environmental Protection Agency Regulations

A. Resource Conservation and Recovery Act Regulations

B. Clean Water Act

C. Clean Air Act

D. Oil Pollution Act

E. Comprehensive Environmental Response, Compensation and Liability Act

F. Emergency Planning and Right-to-Know Act

G. Toxic Substances Control Act

3.8.2.1.2. National Environmental Policy Act

3.8.2.1.3. US Fish and Wildlife Regulations (e.g. Endangered Species Act)

3.8.2.1.4. US Army Corps of Engineers Regulations

3.8.2.2 Occupational Safety and Health Act (OSHA)

3.8.2.2.1. 29 CFR 1910 Occupational Safety and Health Standards

3.8.2.2.2. 29 CFR 1926 Safety and Health Regulations for Construction

3.8.2.3 US Department of Transportation Regulations

3.8.2.4 Code of Federal Regulations

3.8.3 Applicable State, County and Local Codes and Regulations

3.8.3.1 Florida Department of Environmental Protection Regulations

3.8.3.2 Florida Water Management District Regulations

3.8.3.3 Florida Fish and Wildlife Conservation Commission Regulations

3.8.3.4 Florida Department of Community Affairs Regulations

3.8.3.5 County Regulations

3.8.3.6 Florida Department of Transportation Regulations

3.8.3.7 Local Codes and Ordinances

3.8.4 Applicable Industry Codes and Standards from the following list. Alternative standards may be used only upon FPL's acceptance of Contractor's written request, which shall specify the proposed alternative standard, why such change is necessary and how compliance is to be achieved.

3.8.4.1 Mechanical

3.8.4.1.1. ANSI - American National Standards Institute,

3.8.4.1.2. PTC - Power Test Codes - Applicable Test Codes

3.8.4.1.3. ASNT - American Society for Nondestructive Testing

3.8.4.1.4. ASTM - American Society for Testing and Materials

3.8.4.1.5. AWS - American Welding Society

3.8.4.1.6. SSPC - Steel Structures Painting Council

3.8.4.1.7. MSS – Manufacturers Standardization Society

3.8.4.2 Electrical

3.8.4.2.1. ANSI - American National Standards Institute

3.8.4.2.2. FM - Factory Mutual

3.8.4.2.3. ICEA - Insulated Cable Engineers Association

3.8.4.2.4. IEEE - Institute of Electrical and Electronics Engineers

3.8.4.2.5. IESNA - Illuminating Engineering Society of North America

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3.8.4.2.6. ISA - International Society for Measurement and Control
3.8.4.2.7. LPC - Lightning Protection Code
3.8.4.2.8. NEC - National Electrical Code
3.8.4.2.9. NEMA - National Electrical Manufacturers Association
3.8.4.2.10. NESC - National Electrical Safety Code UL - Underwriters
3.8.4.2.11. UL Underwriters Laboratories
3.8.4.2.12. NFPA – National electric code (NEC)
3.8.4.2.13. EN – European Norms
3.8.4.2.14. IEC – International Electric Code

3.8.4.3 Civil/Structural/Architectural

3.8.4.3.1. ACI - American Concrete Institute
A. ACI 318 - Building Code Requirements for Reinforced Concrete
B. ACI Manual of Standard Practice
C. ACI 350R – Environmental Engineering Concrete Structures

3.8.4.3.2. ADA - Americans with Disabilities Act
3.8.4.3.3. AISC - American Institute of Steel Construction
3.8.4.3.4. AISI - American Iron and Steel Institute "Specification for Design of Cold-Formed Steel Structural Members," Parts 1 and 2
3.8.4.3.5. AWS - American Welding Society
3.8.4.3.6. FBC – Florida Building Code
3.8.4.3.7. SSPC - Steel Structures Painting Council

4.0 MECHANICAL SYSTEMS AND EQUIPMENT

4.1 General

4.1.1 Motors

4.1.1.1 General Purpose Induction Motors, 250 HP and below, shall meet NEMA (MG-1), NEC and the following standards and criteria:

4.1.1.1.1. Class F insulation/B temperature rise, Service Factor = 1.15.
4.1.1.1.2. Rated ambient forty degrees Centigrade (40°C).
4.1.1.1.3. TEFC Enclosure for outdoor applications, ODP Enclosure for indoor application.
4.1.1.1.4. Standard Efficiency.
4.1.1.1.5. Standard Balance Rotors or better.
4.1.1.1.6. Space heaters in all motors 25 HP and above (static motor winding heaters are not an acceptable alternate).

5.0 ELECTRICAL SYSTEMS AND EQUIPMENT

5.1 General Requirements

5.1.1 The Plant electrical systems shall be designed to supply power to auxiliary electrical equipment and systems.

5.1.2 Voltage insulation levels, equipment interrupting and continuous current capacities, circuit protection and mechanical strengths shall be selected and coordinated in accordance with calculations and the recommendations of IEEE, ICEA, NEMA and ANSI

5.1.3 Environmental Conditions

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5.1.3.1 MV and LV switchgear, MV and LV MCC's, inverters, DC systems (battery and charger systems), DC and AC distribution panels may be located in pre-fabricated walk-in Power Distribution Centers (PDC's). PDC's shall be environmentally controlled to meet the electrical equipment ambient requirements.

5.1.3.2 Conduit and cable tray entry to outdoor enclosures, panels, switchgear, cabinets, etc. shall not be from the top. Bottom entry is preferred for rain protection. If bottom entry is not practical and side entry is required, entrances shall be installed with watertight fittings or FPL approved flashings.

5.1.3.3 Enclosures for all equipment shall be in accordance with NEMA Standards and type number and shall be suitable for their location as follows:

5.1.3.3.1. NEMA 1.... Indoors (General Purpose)

5.1.3.3.2. NEMA 3R. Outdoors and Indoors (in wet locations)

5.1.3.3.3. NEMA 4.... Outdoors and Indoors (in wet locations – dust tight)

5.1.3.3.4. NEMA 4X. Outdoors - Indoors in wet and corrosion resistant locations

5.1.3.3.5. NEMA 7.... Classified Areas, Class I, Div 1 Group D

5.1.3.3.6. NEMA 9.... Classified Areas, Class II, Div 1

5.1.3.3.7. NEMA 12.. Non-environmentally controlled indoor dusty areas

5.1.3.3.8. Enclosures containing non-arching devices (sealed contacts, terminals, etc.) may be NEMA 12 or 4X in Class I, Division 2 areas.

5.2 Raceway, and Miscellaneous Services

5.2.1 Conduit and Cable Tray

5.2.1.1 Underground conduits shall be schedule 40 PVC direct buried rated or concrete encased rated. Underground conduits may be directly buried in areas that do not require concrete encased duct banks for structural considerations. Use of buried cable is acceptable provided it meets applicable industry codes and standards.

5.2.1.2 Aboveground conduit shall generally be RGS. Aluminum, PVC schedule 80, or PVC-coated conduit may also be used in corrosive areas. Aboveground conduit shall be ¾ inch minimum except ½ inch conduit may be used to connect to instruments or devices with ½" nipples as required.

5.2.1.3 Connections to equipment requiring removal from service or subjected to vibration or movement shall be made with flexible conduit. Liquid tight flexible metal conduit and approved fittings shall be used for outdoor and indoor equipment.

5.2.2 Cable Tray

5.2.2.1 Cable tray shall be per NEMA VE-1.

5.2.2.2 All cable trays, excluding instrumentation trays, shall be provided with external ground wire bonded to the tray and connected to the Plant ground grid at a pre-determined spacing not to exceed 100 feet.

5.2.2.3 Cable trays shall be aluminum or galvanized steel ladder type with tray covers where mechanical protection is necessary. All signal circuits (for levels 1&2) carrying trays shall be galvanized steel or aluminum solid bottom or ventilated trough trays with tray covers

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5.3 Power and Instrument Cable

5.3.1 For 4160v, Medium voltage cable shall be rated 8kV, 90°C or 105°C, stranded copper conductor, shielded, EPR insulation (100% level), and an overall PVC, CPE or CSPE cable jacket. (Note: 5kV at 133% level may be used in lieu of 8kV).

5.3.2 For 6900v, Medium voltage cable shall be rated 8kV, 90°C or 105°C, stranded copper conductor, shielded, EPR insulation (133% level), and an overall PVC, CPE or CSPE cable jacket. (Note: 15kV at 100% insulation may be used in lieu of 8kV.)

5.3.3 Multi-conductor control and power cable shall be rated 600 volts, 90°C, stranded copper conductors, XLP or EPR insulation and an overall PVC, CPE or CSPE cable jacket.

5.3.4 Single conductor wire and cable shall be rated 600 V, 90°C for XLP and 90°C or 105°C for EPR insulation. Single conductor 600 V tray cable greater than #1/0 AWG shall have EPR insulation with a PVC, CPE or CSPE cable jacket. Non-jacketed FREP insulation with appropriate UL flame test may also be used for large single conductor cables.

5.3.5 Single pair instrument cable shall be rated 600 V, XLP or PVC insulation, twisted shielded pairs with drain wires and a PVC, CPE or CSPE cable jacket.

5.3.6 Multi-pair instrument cable shall be rated 600 V, XLP or PVC insulation, twisted shielded pairs with drain wires, overall shield, and a PVC, CPE or CSPE cable jacket.

5.3.7 All custom control panel wiring shall be insulated with 600 V NEC type SIS insulation and all panel wiring shall have wire numbers for identification. Vendor supplied control panels of a proven field design may provide their field proven cable insulation.

5.3.8 The allowable ampacity of power cables shall be in accordance with ICEA and NEC requirements.

5.3.9 Lighting and fixture cable shall be furnished with 600 volt insulation.

5.3.10 Cables shall meet IEEE 383 flame test requirements. All cables installed in cable tray shall be rated for such installation.

5.3.11 For 1000 v, Low voltage cable shall be rated 1kV, 90°C or 105°C, stranded copper conductor, EPR insulation (100% level), and an overall PVC, CPE or CSPE cable jacket.

5.4 Inverters

5.4.1 Inverters shall be utility grade and specifically designed for PV installations.

5.4.2 Inverters shall meet the following minimum standards:

5.4.2.1 UL 1741 - Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources. IEC 62103 or EN 50178 Standards for Inverters for use with 1000 volt DC systems. For 1000 volt DC systems, in the event of conflict, IEC Standards supersede UL Standards.

5.4.2.2 IEEE 929-2000 - Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

5.5 Transformers

5.5.1 Contractor shall design and furnish and install interconnecting transformer(s) that step-up the inverter output voltage to the FPL distribution systems nominal voltage. The interconnecting transformer(s) shall be designed to provide zero sequence current to a ground fault on the FPL feeder (i.e. the PV generation shall be interconnected to the distribution system via a grounded system according to the IEEE-1547 standard).

5.5.2 The Contractor shall provide the interconnecting circuit breaker on the high side of each of the interconnecting transformer(s). The circuit breaker shall be rated for the distribution system voltage and short circuit available current at each corresponding location.

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6.0 CIVIL AND STRUCTURAL FEATURES

6.1 Civil Design Basis

The design for new facilities will require new surveys and topographic information as required for the areas involved in the new construction. Contractor shall be responsible to collect regional and local information regarding regional and local geology and seismology. Contractor shall be responsible for all surveys that are required to determine the final site plans. Contractor shall also be responsible to perform geotechnical investigations as necessary to develop the final site plan.

6.1.1 Surface Surveys and Investigations

6.1.1.1 The position of any surface penetration of underground utilities (i.e., valve station, manhole) within the construction area shall be physically verified by Contractor as part of the site survey.

6.1.1.2 Contractor shall be solely responsible for furnishing all labor, materials, tools and equipment to perform all surveying work and provide all services necessary for, or incidental to construction of buildings, new utilities, and other new facilities; and to establish and maintain benchmarks, to make measurements to verify location of completed construction, and to survey alignment to existing property boundaries. Underground utilities, exclusion zones, and surface penetrations shall be identified on Contractors drawings.

6.1.2 Minimum Soil Requirement Assumptions

6.1.2.1 The Project design shall be based on the following minimum soil requirements:

6.1.2.1.1. 200 psf/ft minimum allowable lateral bearing pressure.

6.1.2.1.2. 400 psf minimum allowable skin friction resisting uplift.

6.1.2.1.3. 2000 Ohm-cm minimum soil resistivity (For Civil/Structural considerations only).

6.1.2.1.4. 7.0 pH minimum.

6.1.2.1.5. Refer to Section 6.3 for maximum allowable deflections.

6.1.3 Easement and Setbacks

6.1.3.1 Contractor shall observe all easements unless specific exceptions are obtained from FPL. Easements shall be identified on the Site Plan Drawings to be developed by Contractor. Minimum setback requirements shall be in accordance with local zoning codes and ordinances.

6.1.4 Contractor shall develop and provide analyses and detailed designs for dewatering systems.

6.2 Site Preparation

The Project design shall take into account existing site conditions with respect to soil characteristics and drainage. Contractor will be responsible for preparing, submitting and securing of all required construction-related permits. Contractor will also be required to prepare and submit any and all site compliance certifications regarding work completion to applicable agencies (e.g. as-built certification of storm water management system, if required).

6.2.1 Site Maintenance

6.2.1.1 All temporary access roadways used by Contractor shall be maintained in serviceable condition.

6.2.1.2 Excess and unsuitable soils will be disposed of on site.

6.2.1.3 Contractor shall be responsible for compliance with State and local requirements for fugitive dust emissions. Contractor shall prevent the spread of dust during its operations.

6.2.1.4 On-site open burning will not be permitted unless approved by appropriate local authorities and FPL.

6.2.2 Fill and Construction Drainage

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6.2.2.1 Any fill that is brought onsite from any offsite location shall meet FPL's clean fill criteria (Exhibit B, Clean Fill Criteria). Testing of the fill at the offsite source shall be performed to assure that the fill meets these criteria.

6.2.2.2 Contractor shall be responsible for installing and maintaining adequate drainage and preventing soil erosion at the site during construction in accordance with State and local sediment and erosion control rules, regulations, and ordinances.

6.2.2.3 Final grade elevations shall be chosen to provide good foundation support for major structures and equipment, and minimize the disposal of excess materials. The foundation design will be based on the recommendations presented in the final geotechnical report.

6.2.3 Excavating, Filling and Backfilling

6.2.3.1 Contractor shall be responsible for furnishing all supervision, labor, tools, materials and equipment, performing all operations in connection with excavating of all materials (excluding pre-existing Hazardous Materials), obtaining fill and backfill materials, installing and compacting of fill and backfill materials and producing final grade lines across the Plant.

6.2.3.2 Contractor shall remove from the site all rubbish and debris found thereon, so as to prepare the site for excavation (Hazardous Materials are excluded).

6.2.3.3 Contractor shall take appropriate measures, including dewatering, to prevent the foundation and trenched areas from becoming unstabilized by the flow of water into the excavation or by cave-ins or slippage.

6.2.3.4 Slopes of excavated areas shall be protected from rutting and scouring. Surface water shall not be permitted to flow uncontrolled down any embankment slope.

6.2.3.5 In areas requiring vehicle access or crane placement, suitable subgrade shall be provided to sustain traffic loads.

6.2.3.6 Contractor's quality of work, including excavating, filling, backfilling, compacting, dewatering, subgrade preparation and stabilization, shoring and drainage shall comply with the geotechnical engineer's recommendations, the applicable American Society for Testing and Materials (ASTM) standards and any State and local standards.

6.2.3.7 Before backfilling, excavated areas to be backfilled shall be cleared of all extraneous materials.

6.2.4 Contractor shall recommend the finish grade material and ground cover to minimize future maintenance requirements.

6.2.5 Control of Water

6.2.5.1 Dewatering to remove groundwater, including any rainwater or surface runoff that enters excavations shall be managed in accordance with the Stormwater Pollution Prevention Plan, South West Florida Water Management District (SWFWMD), County and FDEP requirements.

6.2.6 Soil Erosion and Sediment Control

6.2.6.1 Contractor shall develop soil erosion and sediment control plans. Contractor shall obtain and conform to the local erosion and sediment control regulation.

6.2.6.2 Soil erosion and sediment controls shall generally consist of control of runoff, vegetative stabilization, and sediment traps. All slopes, drainage ditches and other exposed areas shall be stabilized by vegetation. Sediment traps such as hay bales or synthetic filter fabric (silt fence) shall be installed around catch basin inlets, culvert inlets and at the top and toe of slopes. Temporary sedimentation basins shall be provided during construction and converted to permanent basins. Contractor shall maintain erosion and

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sediment control systems throughout construction at the site and any soil disposal areas.

6.2.7 Drainage

6.2.7.1 Contractor shall develop and implement a temporary drainage system for the construction phase of the project. The drainage system shall comply with all federal, State and local regulations. Included shall be the necessary sedimentation and erosion control measures during both construction and permanent operational phases. The drainage system shall be designed to comply with the July, 2002, 40CFR112 Spill Prevention Countermeasures and Control rule changes published in the Federal Register.

6.2.7.2 Contact and non-contact surface runoff from the power block and associated facilities will be collected and routed to on-site stormwater ponds. Construction area runoff shall also be routed to on-site stormwater ponds.

6.2.7.3 All swales shall be erosion control protected by grass and, if required, with man made material or rip rap.

6.3 Foundations

6.3.1 Foundations shall be reinforced concrete designed to support loads imposed. Driven pier foundations are acceptable if design is based on applicable wind loading requirements and allowable bearing values for soil.

6.3.1.1.1. Maximum vertical deflection, based on 4 ½" OD structural member, to be ¾ inches.

6.3.1.1.2. Maximum horizontal deflection, based on 4 ½" OD structural member, to be 1 inch.

6.3.2 Type of foundations required and allowable bearing values for soil shall be confirmed or as recommended by the geotechnical engineer based on the existing subsurface conditions. Differential settlement of foundations due to cut and fill affects shall be calculated and considered in the foundation design. Foundations for heavy equipment are expected to be totally on cut or on fill. If necessary, lean concrete may be added to minimize differential settlements for foundations that are partially on cut and partially on fill. The following foundation design criteria shall be used:

6.3.2.1 Total settlement: 1-1/2 inches. Differential settlement: 0.3 percent slope between adjacent column support points.

6.3.2.2 Foundations shall be designed using static analysis techniques assuming rigid elements and linear soil pressure distribution such that the allowable settlement and bearing pressure criteria are not exceeded. The minimum factors of safety against overturning and sliding shall be 1.5 and 1.25, respectively.

6.4 Concrete

6.4.1 Reinforced concrete structures shall be designed and constructed in accordance with ACI 318, Building Code Requirements for Reinforced Concrete. Concrete work shall conform to the requirements of ACI 301, Specifications for Structural Concrete

6.4.2 Concrete production, proportioning and placing as well as the formwork, reinforcing, joints and embedded items, repair, curing and protection shall all be in accordance with the applicable ACI Standards and Specifications. All concrete mixes shall be approved by the responsible design engineer and submitted to FPL for review and comment prior to use.

6.4.3 Grout shall be pre-packaged non-shrinking grout requiring water only, suitable for the service. Proportioning, mixing, placing, temperature, surface preparation and curing shall be in accordance with manufacturer's requirements. Contractor shall provide the required quality assurance testing.

6.4.4 Reinforcing bars shall be deformed bars conforming to ASTM A615, Grade 60. Welded wire fabric shall conform to ASTM A185.

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6.4.5 Cement shall be Portland cement conforming to ASTM C150, Type (as required by soil conditions).

6.4.6 Aggregates for normal weight concrete shall conform to ASTM C33.

6.5 Site Restoration

All site development areas disturbed during construction, including laydown, parking and temporary office trailers, etc. shall be restored and stabilized in accordance with post-construction stormwater drainage requirements as specified in the Permits.

6.6 Structural Design Basis

The structural design of buildings, structures and portions thereof shall be in accordance with the Florida Building Code, 2004 effective July 1, 2005, and as amended by Desoto County. Structural design loads shall be in accordance with the following:

6.6.1 Wind Loads

Wind loads shall be in accordance with the Florida Building Code, 2004 effective July 1, 2005, and as amended by Desoto County.

6.6.2 Seismic Loads

Seismic loads and element design criteria shall be in accordance with the Florida Building Code, 2004, effective July 1, 2005, and as amended by Desoto County.

6.6.3 Hydrostatic Loads

Below grade structures shall be designed to resist water pressure, corrosion and uplift.

6.7 Steel Structures and Miscellaneous Steel

6.7.1 Steel structures for buildings and equipment support shall be designed, fabricated and erected in accordance with the AISC Specification for Structural Steel Building - Allowable Stress Design and Plastic Design, the Code of Standard Practice for Steel Buildings and Bridges, and the Manual of Steel Construction - Volume II – Connections, and the requirements of OSHA. Steel structures shall also conform to the applicable ASTM Standards, the AWS Codes and RCSC's "Specification for Structural Joints" using ASTM A325 or A490 bolts.

6.7.2 Contractor shall furnish and install steel access platforms, with ladders and galvanized stairs and grating in accordance with the requirements of the Occupational Safety and Health Administration requirements. Access shall be provided for normal operation and maintenance of Plant. Stair access shall be provided where practical with ladder access provided to other less frequently accessed components.

6.7.3 Materials for structural steel and miscellaneous steel shall conform to the requirements of the American Society for Testing and Materials "Standard Specification for Structural Steel" ASTM A36/ASTM A572 Grade 50/ASTM A992, and the requirements provided herein. Structural steel required for tube girts shall conform to ASTM A500, Grade B. All structural and miscellaneous steel shall be hot dip galvanized.

6.7.4 Structural steel checkered plate shall be two-way diagonal raised pattern floor plate. Checkered plate for exterior use shall be galvanized.

6.7.5 Open-web steel joists shall comply with the Steel Joist Institute "Standard Specification and Load Tables."

6.7.6 Metal decking shall comply with SDI "Design Manual for Floor Decks and Roof Decks."

6.7.7 Steel grating shall conform to ASTM A569 with minimum 3/16-inch wide by 1-1/4 inch deep bearing bars. Structural steel grating shall be welded and hot-dipped galvanized after fabrication in accordance with ASTM A123. Grating shall be banded at edges and openings with bars of the same size as the bearing bars. Grating for exterior use shall be serrated.

6.7.8 Ship ladders are not permitted unless approved by FPL.

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6.7.9 Anchor bolts shall conform to ASTM A307, A36, or ASTM F1554 Grades 36, 55, and 105 with nuts conforming to ASTM A563, Grade A heavy hexagon. Anchor bolt sleeves shall conform to ASTM A501.

6.7.10 Expansion bolts shall be unfinished bolts in expansion shell anchors, or wedge bolt anchors. As an alternate Contractor can use drilled holes with anchors set in epoxy, if in accordance with equipment manufacturer requirements.

6.7.11 Anchor bolts shall be used for all structural and building columns, all major equipment, and all vibrating equipment.

6.7.12 Expansion bolts may be used for stairs, ladders, handrails, platform posts, and minor equipment. Expansion bolts shall not be used where the required bolt diameter is larger than 3/4 inch.

6.7.13 Steel pipe for handrail shall conform to ASTM A53, Type E or S, Grade B. Handrails for exterior use shall be galvanized.

6.7.14 Filler metal for welding shall conform to the requirements of AWS D1.1.

6.7.15 A member's end connection shall not have strength less than that provided by a full depth 3/8 inch thick clip angle.

6.7.16 Galvanizing, as specified herein, shall conform to the requirements of ASTM A123 or ASTM A153, as applicable.

6.7.17 Grating shall be welded bar grating, galvanized, banded and secured with clips. Metal decking shall be galvanized.

6.8 Painting

6.8.1 The Project scope shall include protective coating systems on all equipment and building materials except for stainless steel, insulated piping and concrete not exposed to a corrosive environment.

6.8.1.1 Hot-dip galvanized, in accordance with Applicable Industry Codes and Standards, is an acceptable protective coating.

6.9 Fencing

6.9.1 Site perimeter fence shall be 7 feet high and have an overall height of 8 feet from the bottom of the fabric to the top barbed wire. The fence shall have top rail, bottom tension wire, and three strands of barbed wire mounted on 45 degree extension arms. The upper strand shall be approximately 12 inches out from the fence and 12 inches above the top of the fabric. Posts shall be set in concrete as detailed.

6.9.2 Materials for site chain link fencing shall be as follows. All steel or malleable iron parts and accessories shall be hot-dip galvanized in accordance with ASTM A123 after fabrication.

6.9.2.1 Fabric - 9 gauge, 2 inch mesh; galvanized ASTM A392, Class 2; twisted selvage on top, knuckled selvage on bottom.

6.9.2.2 Posts - Steel pipe, ASTM F1083 standard weight (Schedule 40).

6.9.2.3 Line posts - 2-3/8 inch OD pipe, 3.65 lb per ft.

6.9.2.4 Terminal posts (end, corner, and pull) - 2-7/8 inch OD pipe, 5.79 lb per ft.

6.9.2.5 Gate posts (swing gates) - Gate or leaf 6 ft wide or less, 2-7/8 inch OD pipe, 5.79 lb per ft; gate or leaf over 6 ft wide and up to 13 ft, 4 inch OD pipe, 9.10 lb per ft; gate or leaf over 13 ft and up to 18 ft wide, 6-5/8 inch OD pipe, 18.97 lb per ft; gate or leaf over 18 ft wide, 8-5/8 inch OD pipe, 28.55 lb per ft.

6.9.2.6 Top Rail - 1-5/8 inch OD (Schedule 40) pipe, 2.27 lb per ft; or 1-5/8 by 1-1/4 inch roll formed sections weighing 1.35 lb per ft.

6.9.2.7 Post tops - Pressed steel, malleable iron with pressed steel extension arm, or one-piece aluminum casting with hole for top tension wire, designed to fit over the outside of the posts and to prevent entry of moisture into tubular posts.

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6.9.2.8 Barbed wire Galvanized, ASTM A121 Class 3; two 12-1/2 gauge steel wires with 4 point round 14 gauge barbs spaced 5 inches apart.

6.9.2.9 Stretcher bars - Steel, 3/16 by 3/4 inch, or equivalent cross-sectional area.

6.9.2.10 Fabric ties - Aluminum bands or wires.

6.9.2.11 Gate frames - 1-7/8 inch OD (Schedule 40) pipe, 2.72 lb per ft; or 2 inch square, 4.32 lb per ft.

6.9.2.12 Tension wire - Galvanized coil spring wire, 6 gauge ASTM A641 Class 3.

6.9.2.13 Setting cement - Minwax "Super Por-Rok Cement" or Master Builders "Set 45."

6.9.3 Site gates shall be swing type, hinged to swing 180 degrees from closed to open, complete with frames, latches, stops, keepers, hinges, fabric, braces, pad-locks, and three strands of barbed wire. Gate leaves, except those on walk-through gates, shall have intermediate members and diagonal truss rods as required for rigid construction and shall be free from sag or twist. Gates shall be fitted with vertical extension arms or shall have frame end members extended to carry barbed wire. Joints between frame members shall be made by welding or by means of heavy fittings and shall be rigid and watertight. Truss rods shall be not less than 3/8 inch diameter. Gate fabric shall be same as fence fabric and shall be attached to frame ends by stretcher bars, bolt hooks, or other mechanical means.

6.9.3.1 Hinges shall be heavy pattern with large bearing surfaces and shall not twist or turn under the action of the gate.

6.9.3.2 Latches shall be plunger bar type, full gate height, and arranged to engage the gate stop, except single gates less than 10 feet wide may be provided with a forked latch. Latches shall be arranged for padlocking with the padlock accessible from both sides of the gate.

6.9.3.3 Stops shall consist of a roadway plate with anchor set in concrete and arranged to engage the plunger.

6.9.3.4 Keepers shall consist of mechanical devices for securing and supporting the free end of the gates when in the full open position. Keepers shall be mounted on 2-7/8 inch outside diameter pipe posts filled with concrete and set in concrete foundations.

6.9.3.5 Gates shall be installed so that they cannot be removed without disassembly of the hardware. Hardware attachment bolts shall be peened so that removal will be difficult.

6.9.4 The installed site fence shall conform to the alignment and finish grade indicated. Unless otherwise indicated or specified, all posts shall be plumb and spaced 10 feet apart. Where necessary, the fence grade shall be adjusted to fit the ground contour by slipping the fence fabric links.

6.9.5 Ground surface irregularities shall be graded as required to minimize changes in vertical alignment and to provide a smooth profile for the fence. Clearance below the bottom of the fence shall not exceed 2 inches.

6.9.6 The plan and profile of each reach of fence between corner posts, or between corner posts and gate posts, shall be straight. Ground surfaces shall be graded as required to achieve the straight profiles before each reach of fence is installed.

6.9.7 Top rail and bottom tension wire shall be installed before the fabric. To minimize raising the bottom of the fence to gain access, bottom tension wires shall be installed in the lowest position possible (approximately 6 inches above grade) and shall be attached to each post and securely anchored at terminal and gate posts. Straight runs between braced posts shall not exceed 1,500 feet. A terminal post shall be provided at each change in slope.

6.9.8 Fabric shall be attached to the top rail and bottom tension wire at 24 inch centers and to the line posts at 15 inch centers, all on the security side of the fence. Barbed wire

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shall be fastened to each extension arm by internal clips or external fabric ties. Stretcher bars shall be provided at each gate, terminal, and pull post. Each stretcher bar shall be threaded through the fabric and anchored to the post at 15 inch centers by positive mechanical means.

6.9.9 Each gate and terminal post shall be braced by a horizontal pipe brace and an adjustable truss extending to an adjacent line post. Corner posts located where the deflection angle is 10 degrees or greater shall be braced in both directions.

7.0 INSTRUMENT AND CONTROL SYSTEM

7.1 General

7.1.1 The Plant's instrument and control systems shall be designed to provide for the safe and efficient start-up, operation, shutdown and emergency shutdown of the Plant.

7.2 Instrumentation General Design and Installation

7.2.1 All instruments and equipment shall be installed in a manner which assures reasonable protection against mechanical damage, wetting, or extremes of heat or cold. Instrumentation shall be stored in accordance with the manufacturer's recommendations until installation. Final locations and orientations must be selected for accessibility, repair, and calibration in place, easy access to the rear of the instruments (if needed), and for disconnection without resorting to cutting, burning, or welding.

7.3 Instrument Cabinets and Local Control Panels

7.3.1 Local Instrument Rack / Enclosure / Cabinet Installation

7.3.1.1 Instrument racks/enclosures/cabinets shall be secured to structural steel or to concrete. Racks/enclosures/cabinets shall be electrically grounded. Bolting to bare or galvanized metal shall be used for attaching a ground strap.

7.3.1.2 Prior to installation, Contractor shall ensure that instrument racks/enclosures/cabinets have sufficient clearances for the required blowdown piping and headers, door swing radius, etc., and that the racks/enclosures/cabinets are completely accessible for maintenance.

7.3.1.3 The racks/enclosures/cabinets shall be installed and anchored in place so that they are level and plumb and properly aligned in accordance with the above mounting requirements.

7.3.1.4 Racks/enclosures/cabinets shall not be supported by handrails. All instrument line penetrations into instrument enclosures/cabinets shall be through bulkhead fittings (couplings). Bulkhead couplings shall be supplied on instrument enclosures/cabinets for each instrument location. Top entry of instrument cabinets or instrument enclosures/cabinets junction boxes is prohibited. Bottom entry is the preferred method for conduits.

7.4 Local Instrument Cabinets / Racks

7.4.1 Instrument and Control Wiring and Instrument Cabinet Wiring

7.4.1.1 Both ends of conductor or wire pair shall be identified with a wire number or instrument tag number.

7.4.1.2 All necessary precautions shall be taken to maintain a high standard of cleanliness during storage and assembly. All metal chips, turnings, rust, dust, weld splatter, scale, and other particles shall be removed without destroying the continuity of the surface.

7.4.2 Marking

7.4.2.1 Contractor shall install stamped stainless steel tags for the following Contractor purchased equipment:

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7.4.2.1.1. All instruments shall be tagged with the appropriate instrument tag number. Tags shall be secured with stainless steel wire with ends crimped together.

7.4.2.1.2. Each local instrument cabinet shall have a stainless steel tag permanently affixed to the cabinet front.

7.4.2.1.3. Each cabinet mounted instrument shall have a tag affixed to the instrument.

7.4.3 Continuous Monitoring System

7.4.3.1 Contractor shall provide a continuous monitoring system (Data Acquisition system – DAS) that is capable of providing real-time performance monitoring, historical data storage and retrieval, and Internet accessibility of data.

7.4.3.1.1. The monitoring system shall provide AC energy production on the individual inverter level.

7.4.3.1.2. The monitoring system shall provide solar irradiance, ambient temperature and wind speed.

7.4.3.1.3. All monitored information is stored on the data logger as 15 minute averages and transmitted for processing, storage and backup. For added security, the DAS shall include a battery backup, so it can store up to four weeks of data.

8.0 PROJECT SPECIFIC CONSTRUCTION REQUIREMENTS

8.1 Lay down and Storage Requirements

8.2 Condition of Delivery of Equipment and Materials

8.2.1 In general, equipment and materials will be delivered to the site by truck. Contractor shall coordinate the ordering, delivery, and storage of all materials necessary for the performance of its Work, and Contractor shall be responsible for damage, loss, theft, casualty, shortages, shrinkage, and non-conformance of materials and equipment.

8.2.2 Truck deliveries and traffic shall comply with permit requirements.

8.3 Construction Support Facilities

8.3.1 Contractor shall provide all necessary temporary facilities at the site to support its staff and labor force and the delivery, unloading and storage of equipment and materials.

8.3.2 Contractor shall provide copies of drawings/specifications/ vendor manuals or other documents that FPL requires on-site during the project. Contractor shall also provide FPL personnel access to document control for specific information needs.

8.3.3 Any temporary storage facilities shall be capable of meeting any state, federal, or local requirements.

8.4 Construction Quality Control

8.4.1 First line, primary inspection and testing (hereafter referred to as Quality Control) are the responsibility of Contractor. Contractor's quality control procedures shall be clearly stated in the Quality Control Manual, and shall specify field inspections and inspection criteria. A summary of FPL's minimum requirements for Contractor's Inspection/Testing program is identified below. These minimum requirements are to be supplemented with additional requirements as determined by Contractor as specifications are developed and code requirements are identified. Problems discovered during inspections and testing which could impair job cost, schedule, or Plant function, will be immediately conveyed to FPL. Contractor's Quality Program must also include Contractor Quality Assurance.

8.4.2 Contractor shall conform to prevailing quality industry standards in accordance with Contractors profession in the location of the project. Any work which does not meet this standard of care shall be repaired, replaced, and re-performed at the sole expense of Contractor.

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8.5 FPL's Scope of Services-Quality Assurance

8.5.1 FPL will perform an overview of the Quality Control function as practiced by Contractor. This overview does not include "Hold" or "Witness" points. Every effort will be made to implement a meaningful overview inspection without impeding Contractor's efforts or job progress. The overview is intended to assist Contractor in meeting design and code requirements, and to prevent deficient material/workmanship rather than to identify it after the fact. FPL's representatives will conduct the overview inspections. Concerns arising from the overview inspection will immediately be conveyed to Contractor for incorporation into Contractor's Quality Control Program for corrective action, recurrence control, and trending. FPL's representatives will continually monitor and evaluate Contractor's timeliness and adequacy of corrective actions and recurrence controls.

8.5.2 As a means of assuring that the performance of the Work fulfills the requirements of the Contract Documents, Contractor shall maintain a Quality Management Organization, which provides Quality Control/Quality Assurance expertise in a number of key areas. The program shall be capable of providing assurance that the receipt, storage, erection, installation, testing, and examination of all equipment, components, materials, and services will comply with the requirements of the Contract documents. The Quality Program shall be documented in a Quality Control Manual, which shall be submitted to FPL for approval 30 days after Notice to Proceed.

9.0 STARTUP AND COMMISSIONING REQUIREMENTS

9.1 General Requirements

9.1.1 Contractor shall provide FPL a Startup Execution Plan document that describes in detail all aspects of the Startup and Commissioning Program including how commissioning activities shall be incorporated into the design, procurement and construction of the Work. The Execution Plan shall be submitted to FPL for review and approval. FPL's approval shall not be unreasonably withheld.

9.2 Scope of Startup Program

9.2.1 Contractor shall supply all required labor to execute the startup plan and supply all test and calibration equipment, materials, and services necessary to perform all testing, system calibration, checkout, functional testing and initial operation as well as make adjustments, perform event and trip analysis to determine the root cause, and correct deficiencies, completely in accordance with this specification.

9.2.2 Construction Turn-over and Pre-commissioning

9.2.2.1 As the various subsystems, systems and equipment packages are brought to a state of mechanical completion by Contractor's construction organization they will one by one be turned over to Contractor's startup organization by means of a pre-commissioning procedure. Contractor will perform the non-operational adjustments, and checks to verify that each item of equipment, subsystem, package and system is ready for operational start-up and testing.

9.2.2.2 The following activities and verification steps are included:

9.2.2.2.1. Physical construction complete (a checklist shall be provided by Contractor).

9.2.2.2.2. Compile associated documentation for code compliance, QA/QC, design basis.

9.2.2.2.3. Complete post construction testing (i.e. cold alignment, bump motors for rotation, pressure test, bolt torque, electrical insulation, contact resistance for field assembled electrical connections, and continuity tests, etc.).

9.2.2.2.4. Complete cleanup, painting, insulation and/or punch-list items sufficiently to safely perform the startup testing and initial operation.

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9.2.2.3 As the pre-commissioning for each individual item of major equipment, subsystem and major system is completed it will be documented with a turnover package demonstrating that it is ready for commissioning. The pre-commissioning package shall contain the procedures for executing the above activities, and documentation of their results. The package may be a subset of the Startup Turnover Package.

9.2.3 Start-Up Program Field Activities

9.2.3.1 During this phase Contractor will perform the calibration, testing and operation of the various portions of the Plant, starting with component tests, and then progressing through tests of subsystems and complete systems, and then operation of the Plant as a whole. The overall startup sequence and logic shall be developed by Contractor's Startup Manager so that subsystem startup packages are completed and presented to FPL's Operations Department in proper sequence to support an orderly startup. Coordination of Startup Activities shall include the following:

9.2.3.2 From commencement of startup activities, Contractor's startup personnel, under the direction of Contractor's Startup Manager, will directly coordinate all such activities for energization and operation of equipment and systems being started up.

9.2.3.3 Contractor's Startup Manager will initially hold weekly and later, daily startup coordination meetings. Contractor's Startup Manager and FPL will mutually agree on the frequency of the meetings. All subcontractors performing work in areas currently being readied for subsystem turnover for operation shall attend, as well as Contractor's Construction Superintendent, appropriate manufacturer's technical representatives, and FPL's representative. The meeting shall include a review of activities since the last meeting and a look ahead at activities planned for the next two weeks.

9.2.3.4 Contractor shall maintain a single integrated punch-list of outstanding activities for the construction, commissioning, startup, and initial operation of the project. FPL shall have the authority to add or delete items from the punch-list.

9.2.3.5 FPL may elect to witness any or all pre-commissioning or startup activities. The coordination meeting shall serve as the mechanism for notifying FPL of when activities are taking place.

9.2.3.6 Contractor shall provide written procedures for use by Contractor's commissioning team and FPL's plant operating staff for all Commissioning Procedures.

9.3 Operating Mode, Capability Verification and Guaranteed Performance Tests

9.3.1 The Plant shall successfully complete the Operating Mode Tests, the Capability Verification Tests and the Guaranteed Performance Tests in accordance with Appendix HH(Performance Testing), to demonstrate compliance with the Agreement requirements for Minimum Performance Levels and Guaranteed Performance Levels.

9.3.1.1 Operating Mode Tests – Test(s) that demonstrate the capability of the Plant to operate automatically from morning startup, through the day, and evening shutdown. Test should also demonstrate the capability of the Plant to automatically operate in response to abnormal operating conditions, such as the failure of an inverter, distribution system disturbances, etc.

9.3.1.2 Capability Verification Tests – Test(s) that demonstrate the capability of the Plant to operate automatically, safely, and reliably over the full range of capacity, from startup to full capacity.

9.3.1.3 Guaranteed Performance Tests – Test(s) that demonstrate the guaranteed capacity of the plant.

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9.3.2 Contractor shall provide the Plant performance test procedures that will demonstrate the Plant meets the required performance specifications.

9.3.3 Contractor shall be required to provide to FPL, for review and acceptance, detailed documents for these tests (test procedures) which will include but not be limited to:

9.3.3.1 Description of the test

9.3.3.2 List of all data to be collected

9.3.3.3 Instrumentation and location for taking all data points

9.3.3.4 Correction curves

9.3.3.5 Instrument and test accuracy's

9.3.3.6 Sample calculations

9.3.4 The draft Test documents shall be submitted for review at least 120 days before the expected test date. FPL shall provide comments within thirty (30) Business Days. Contractor will provide written response to FPL's comments within 10 Business Days and make necessary modifications to the test procedures.

9.4 Environmental Control Program

9.4.1 Contractor shall develop and maintain an Environmental Control Program document to assure that all construction and start-up activities associated with the Project conform to best environmental practices, federal, state and local regulations, applicable permit conditions, conditions of certification, Environmental Rules for Contractors, and any other construction and start-up constraints identified in the Project's environmental permitting process. A secondary purpose of the Environmental Control Program is to provide the basis for emergency response programs that will be in place during construction and operation of the Project. The Program shall include an Environmental Control Plan and all other relevant program documents (i.e., permit matrices, storm water pollution prevention plan, spill prevention, control and countermeasure plan, emergency response plan, copies of permits, etc). The Environmental Control Program document will provide all relevant references for the project's environmental management.

9.4.2 The Environmental Control Program shall include an Environmental Control Plan that describes the processes that will be followed in order to comply with applicable Laws and permits. The plan assigns specific responsibilities for compliance with environmental restrictions and response to emergency situations during construction and startup of Project facilities.

9.4.3 The Environmental Control Program document shall also include a matrix of permit compliance activities, due dates, responsible person and current status. Copies of Contractor's and FPL's environmental permits applicable to the Project shall be included in the document.

9.4.4 The Environmental Control Program document shall be submitted to FPL for review and approval no later than 30 days prior to site mobilization.

9.5 FPL Notification

9.5.1.1 In the event Contractor becomes aware of any imminent conditions of non-compliance or receives either a Letter of Non-Compliance or Notice of Violation, Contractor shall immediately contact FPL and initiate appropriate measures to correct the non-complying condition or activity and prevent its recurrence.

9.6 FPL Audits

9.6.1.1 FPL shall reserve the right to conduct periodic quality control/quality assurance assessments and environmental audits of Contractor's project activities. Assessment and Audit findings in non-compliance with project permit requirements shall be immediately corrected by Contractor.

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10.0 PROCUREMENT

10.1 Selection of Equipment Suppliers

10.1.1 Contractor shall procure equipment in accordance with the requirements of the Agreement from reputable suppliers who normally produce the type of equipment specified for use in heavy industrial applications.

10.1.2 Where specific requirements for equipment are included herein, Contractor shall ensure that these requirements are included in Contractor's specifications and complied with by the selected manufacturer. Contractor shall be responsible for proposing resolutions to any exceptions taken by suppliers to the requirements outlined herein and obtaining FPL's concurrence with these resolutions prior to accepting the exceptions.

10.1.3 FPL's review of these exceptions will be limited to ensuring compliance with the intent of these specifications, specifically to establish a minimum level of quality and functionality. FPL's concurrence or comments will be forwarded to Contractor within ten (10) Business Days of the date they are received in FPL's offices.

10.1.4 For other equipment, manufacturers and model numbers listed in this Technical Specification are representative only of the quality of equipment proposed. Manufacturers and model numbers of equal quality may be substituted for those listed in this Technical Specification.

10.1.5 Contractor shall have the obligation of ordering, receiving delivery of, storing, caring for, and installing such equipment and materials. Contractor shall coordinate the ordering, delivery, and storage of all materials necessary for the performance of its Work, and Contractor shall be responsible for damage, loss, theft, casualty, shortages, shrinkage, and non-conformance of materials and equipment.

10.1.6 No substitutions shall be made in the Work unless permitted in the Agreement and only then upon Contractor receiving prior written approval.

10.2 Vendor Inspection

10.2.1.1 FPL reserves the right to participate in scheduled vendor inspections of any equipment supplied under the terms of this Contract in accordance with the terms of the Contract. Contractor shall submit to FPL, prior to use, a listing of planned inspections for the major equipment to be supplied.

10.3 Material and Equipment Quality Control

10.3.1.1 Contractor shall provide new equipment, materials, and workmanship suitable for this application.

10.4 Inspection and Shop Testing

10.4.1 Contractor shall provide for shop inspection and testing of major equipment as determined by Contractor. Testing programs shall be established by Contractor, but shall not be less thorough than the manufacturer's standard testing procedures. Contractor is responsible for insuring that the manufacturers conform to the manufacturing specifications for quality, inspections and testing contained in all equipment contracts.

10.4.2 FPL reserves the right of shop inspection visits and may witness shop tests in accordance with the terms of the Agreement. Shop inspections by FPL do not relieve Contractor of responsibility contained in the Agreement. Contractor shall endeavor to notify FPL of the tests at least 5 Business Days in advance of tests.

10.4.3 Contractor shall submit certified copies of test reports and shop tests, to FPL.

11.0 PROJECT ADMINISTRATION

11.1 Project Meetings

11.1.1 During all active phases of the Project, Contractor shall be required to participate in a monthly Project Review Meeting with FPL. During the engineering, design, and procurement phases of the Project, this meeting will normally be held in Contractor's home office. Each of Contractor's lead discipline engineers will be required to update

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FPL's organization on the discipline progress to date, review design activities currently in progress, and discuss problem areas and the plan developed by Contractor to address and resolve them. After the start of construction, the monthly Project Review Meetings will normally be held in Contractor's site office and will be attended by Contractor's Project Manager, Project Engineering Manager, Home Office Construction Manager, Site Construction Manager, Startup Manager, and Project Controls Engineer. Update responsibilities and activities will correspond to those identified for the pre-construction phases of the project in the preceding paragraph.

11.1.2 In addition to the monthly meetings, Contractor shall submit a monthly progress report which includes schedules, detailing progress against the Level 2 CPM schedule, percent complete curves for the engineering and construction phases of the project, bulk commodity installation progress curves, and a discussion of problem areas and proposed resolutions. Attached to this report, Contractor shall provide current revisions of the purchase order, contractor drawing, and vendor drawing lists.

11.1.3 Between Project Review Meetings, Contractor shall conduct weekly construction/startup review meeting with all key site personnel in attendance. FPL's Representatives may attend these meetings.

11.2 Document Preparation Requirements

11.2.1 Contractor shall produce all engineering documentation normally required for a project of this type, including, but not limited to, flexibility and expandability requirements, design objectives and constraints design studies and analyses, design calculations, equipment specifications and detailed design drawings.

11.2.2 The design documents shall be certified and approved by a licensed professional engineer and architect, and such other certified professionals as required by Law. Prior to Final Acceptance, Contractor shall turn over to FPL copies of all engineering documentation.

11.3 Project Submittals

11.3.1 Contractor shall supply the following drawings and information to FPL as part of the scope of Work. Items marked with an asterisk (*) shall be submitted for FPL's review. The transmittal of documents for FPL's review shall be by letter referencing that the documents are submitted per this Section of the Contract. Any comments from FPL shall be returned within ten (10) Business Days. As-builts shall be provided for the site plan, array layout and shading drawings, underground electrical drawings, electrical wiring and control wiring diagrams

11.3.1.1 *Site Plan

11.3.1.2 *Array Layout and shading diagrams

11.3.1.3 *Underground electrical drawings

11.3.1.4 *Erosion and Sedimentation Control Plans

11.3.1.5 *Dewatering Plans

11.3.1.6 *Electrical diagrams

11.3.1.7 *Array wiring diagrams

11.3.1.8 *Structural drawings

11.3.1.9 *Finish Grading and Paving drawing

11.3.1.10 *QA/QC Manual (Project Execution Plan and Project Coordination Procedure Manual)

11.3.1.11 Calculations substantiating any portion of the design, that is normally provided on request by FPL.

11.3.1.12 Drawings and Operating & Maintenance manuals for all equipment provided in Contractor's scope of work.

11.3.1.13 *Performance Test Procedures in accordance with 9.3.5.

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11.3.2 All vendor drawings shall be sent to FPL in electronic format. Each vendor drawing shall be sent with a unique file number.

11.3.3 Contractor shall prepare and provide (including routine updates) to FPL, all typical lists including, but not limited to, the following:

11.3.3.1 Spare parts and special tools lists

11.3.3.2 Electrical Load List (Motors, Heaters, etc.)

11.3.3.3 Equipment List/Instrument List

11.3.3.4 Overall Plant Control Scheme

11.3.3.5 Instrument Data Sheets

11.3.3.6 Cable and Conduit Schedule

11.3.4 At the conclusion of the project and prior to Final Acceptance, Contractor shall supply to FPL a set of compact discs (CD's) containing final revision of the drawings and documents listed above.

12.0 INTERCONNECTION PROTECTION AND METERING EQUIPMENT

12.1 Protective Relay Systems

12.1.1 FPL shall provide the PV plant generation interconnection protective relay systems for the Project. The protective relay panels will be installed by the Contractor. The interconnection protection will include a fiber optic communication system. This protective relay equipment will be installed in the by the Contractor.

12.2 Interfaces

12.2.1 Interfaces between the PV plant switchgear and other plant electrical systems, and the FPL interconnecting protective relay equipment will be provided by the Contractor.

12.3 Cable

12.3.1 Cable and conduit runs between the PV generating facility equipment and the interconnection protective relay equipment will be provided and installed by the Contractor.

12.4 Revenue Meters

12.4.1 The revenue meter will be provided and installed by FPL. The revenue metering transformers will be provided by FPL and will be installed by the Contractor on structures designed and installed by the Contractor. The conduit runs from the metering transformers to the meter cabinets will be provided by the Contractor. FPL will provide the metering cables to be installed by the Contractor. The metering transformers will be provided and installed by the Contractor. The transformers may be installed in the LV equipment provided by the Contractor. The location of the metering transformers shall be reviewed and approved by FPL. Conduit runs between the metering transformers and the metering cabinet shall be provided by the Contractor. The metering cables will be provided by FPL.

ECRC-08-2960
HEARING EXHIBIT - 00000130

Appendix A – Scope of Work
Exhibit A – Environmental Rules for Contractors

HEARING EXHIBIT - 00000131

APPENDIX A
EXHIBIT A
ENVIRONMENTAL RULES FOR CONTRACTORS

1. This document must be made a part of all contracts and subcontracts by the EPC contractor for work to be performed on the Project site.

2. All contractors and subcontractors must review site orientation documents and sign affidavit if required by FPL Project Construction Manager (PCM). All contractors must implement an Environmental Control Program, reviewed and approved by FPL, as specified in the Scope of Work documents.

3. All contractors and subcontractors must inform the FPL Project Construction Manager (or designee) in writing of the type and amount of any chemicals (prior to their delivery to the site) to be brought on-site to complete the work. All contractors and subcontractors shall further notify the FPL PCM in writing during the course of construction, if any additional chemicals are to be brought on site.

4. All contractors and subcontractors must provide Material Safety Data Sheets (MSDS's) for all chemicals as directed by the FPL PCM prior to chemicals being brought on-site. Per the OSHA Hazard Communications standard, MSDS's must be maintained (by all contractors and subcontractors) on-site for any chemicals that could pose a health or physical threat to personnel, and all personnel must be Hazard Communication trained. The FPL PCM is responsible for ensuring that required Hazard Communication training is provided to FPL employees potentially exposed to these chemicals. Contractors are responsible for training their personnel.

5. No hazardous materials may be brought onto the Project site unless necessary for contracted work. Arsenic free bentonite shall be used for all drilling.

6. Waste management, including determination of the type of waste, quantity, and appropriate storage prior to off-site disposal, must be coordinated with the FPL PCM.
   - All contractors and subcontractors must provide FPL PCM with waste minimization plans. [Plans often include product substitution, process changes to eliminate or reduce chemical use, and/or recycling or reusing materials;]
   - Copies of any analyses performed to classify wastes as hazardous or non-hazardous must be given to FPL PCM and copied to FPL Environmental Services;
   - Hazardous materials used and hazardous waste generated must be stored in temporary or permanent secondary containment in areas agreed to by FPL PCM;
   - Secondary containment structures shall be maintained free from stormwater or other materials that defeat the purpose of the secondary containment. Stormwater or other materials removed from secondary containment structures must be managed appropriately.
   - All wastes must be stored in designated hazardous and non-hazardous containers appropriately labeled prior to proper disposal.
   - All original manifests, shipping papers, certificates of disposal, or other documents associated with waste transport and disposal must be provided to FPL PCM. Waste manifests must be signed by FPL contractor or subcontractor whose EPA ID number is used for waste disposal (unless otherwise specified – e.g., FDEP may required use of Substation's EPA ID number for contiguous project operations. In this case strict waste minimization and management is required in order to prevent changing current waste generation status of Substation).
   - All contractors and subcontractors must inform FPL PCM of all disposal sites to be used for hazardous and non-hazardous wastes prior to contract award;
   - All contractor and subcontractor employees responsible for managing hazardous wastes must be properly trained. Documentation of that training is to be provided to the FPL PCM and to FPL Environmental Services.
   - Hazardous materials releases or spills of any kind must be reported immediately to the FPL PCM (see Item 7); and
   - Contractor must consult with FPL PCM to determine if hazardous waste identification number should be obtained prior to contract award.

7. All contractors and subcontractors must coordinate with FPL PCM for proper storage of flammable or other types of chemicals.

8. All contractors and subcontractors are responsible for knowing and complying with all local, state and federal reporting and response requirements for releases or spills of oil, petroleum products, onsite products and

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chemicals, hazardous materials or hazardous wastes. All contractors and subcontractors must ensure that spill prevention measures are in place during the course of work at the Project site. This includes:

- Ensuring that all containers are closed at the end of each work day;
- Use of temporary hoses is carefully planned;
- Secondary containment is used for work near drains;
- All fuel and oil tanks used by all contractors and subcontractors must be placed in temporary secondary containment on an impervious surface;
- All contractors and subcontractors must maintain appropriate spill clean-up equipment near tanks and equipment that have potential for leaks;
- Following work and prior to start up, all contractors and subcontractors must ensure that all valves, manways, and pipelines are closed if appropriate to minimize risk of spills;
- All contractors and subcontractors must assume that all "out-of-service" lines will leak when brought back into service – appropriate spill containment measures must be taken;
- All contractors and subcontractors must document the training of personnel in spill awareness, notification (internal FPL/Agencies), and identification of spill risk areas; and
- All contractors and subcontractors must review the site's spill plans and know appropriate FPL site contact in the case of **ANY** spill. All contractors and subcontractors must coordinate with FPL PCM in order to understand the plant's spill response plans.

9. All contractors and subcontractors must comply with all applicable local, state, and federal laws in the course of performing work at the Project site. All contractors and subcontractors must coordinate with FPL PCM to ensure that the terms of permits and conditions of site certification to conduct work are met. Copies of any and all permits acquired by all contractors and subcontractors shall be provided to the FPL PCM. All contractors and subcontractors must coordinate any contact with regulatory agencies with the identified FPL contact.

10. All contractors and subcontractors must include environmental issues in daily safety tailgate sessions. FPL PCM should attend meetings when possible.

11. If work is conducted on Risk Management Plan (RMP) or Process Safety Management (PSM) regulated system, all requirements in the RMP and PSM documents must be reviewed/coordinated with the designated FPL contact and addressed during the course of work.

12. All contractors and subcontractors are required to maintain "good housekeeping" during the course of the project and must perform a thorough site clean-up following completion of the work. All unused products / chemicals are the property of the contractor and must be removed from the site at the end of the job unless specific arrangements are made with the PCM. All contractors and subcontractors must inform the FPL PCM when chemicals have been removed from the site.

13. All contractors and subcontractors must conduct a post-project site "walk-down" with the FPL PCM and plant environmental specialist to ensure that environmental issues are addressed and resolved.

14. All required erosion control/stormwater pollution prevention practices must be implemented and documented as required by regulations, Stormwater Pollution Prevention (SWPP) Plans or Best Management Practices (BMP) Plans. A listing of these requirements shall be coordinated with FPL PCM. Contractor is responsible for development and implementation of such plans. Conditions of Certification and / or all other applicable permit conditions must be strictly observed.

15. Threatened and endangered species are not expected to be present either in or near the Project area. Federal, state and local rules and regulations are designed to protect these species from harassment and harm. If threatened and endangered are observed on or near the site, the contractor and subcontractors are obligated to comply with these rules and regulations.

EXHIBIT A
APPENDIX A
ENVIRONMENTAL RULES FOR CONTRACTORS
(continued)

ENVIRONMENTAL FIELD INSPECTION FORM

FACILITY: _____ **DATE:** _____

Instructions:

Walk site *at least once a week* and review each of the following areas

Explain each "No" answer in the comment section

Sign completed form and provide to FPL Project Manager with copy to FPL Environmental Services

General Environmental Management		**YES**	**NO**
1	Is housekeeping in all areas in good condition? All areas should be neat, orderly, and clean.		
2	Is the site free of any dead animals?		
3	Are spill cleanup materials and equipment in good condition and in close proximity to where they might be needed?		
4	Does security appear adequate? Fencing, locks, and lighting are in good condition.		
5	Are all contractors and subcontractors following the FPL Environmental Rules for Contractors? Has the Environmental Control Plan been implemented effectively?		

Waste Management		**YES**	**NO**
6	Is sandblast or bead blast material swept up? All material should be swept and contained for proper disposal. **Note that blast material containing metals could be hazardous waste; appropriate testing and documentation must be performed.*		
7	Are trash receptacles free of the following hazardous, universal, or recyclable waste? • Aerosol cans • Containers with product (e.g. paint, solvent) • Saturated oily rags or absorbent pads (SC – any oily rag/wiper prohibited) • Rags or absorbent pads with solvent odor • Discarded equipment that contains refrigerant • Recyclable items (aluminum cans, metal, cardboard, paper, etc.) • Universal waste (mercury containing lamps, batteries, pesticides, thermostats) • Tires		

ECRC-08-2964 HEARING EXHIBIT - 00000134

ENVIRONMENTAL FIELD INSPECTION FORM

		YES	NO
8	Is waste properly contained in drums? • Bungs closed and no open funnels • Lids sealed tight • Clearly labeled with contents • Where contents are flammable, drum is grounded • Drums not stacked • Outside of drum clean; no evidence of waste product		
9	Are drums in good condition (includes empty drums)? • Free of dents • Free of holes • Free of rust • Free of bulges or leaks		
10	Is hazardous waste secondary containment in good condition? • Free of cracks, gaps, waste product, and no breaching • Containment drains closed		
11	Is hazardous waste secondary containment free of product or water?		
12	Is the emergency equipment in the hazardous waste storage area in working order? • Telephone or paging system must work properly • There must be a fire extinguisher present that is inspected monthly • Spill clean-up equipment must be present and in good condition • If the facility is a small quantity generator, emergency response information must be posted near the communication system.		
13	Will the isles in the Hazardous Waste Satellite and Accumulation (storage) areas allow for movement of emergency response equipment? • Must be able to see all sides of drum for markings and drum conditions.		
14	Is the accumulation start date on all drums in hazardous waste storage for disposal area?		
15	Are used oil drums and tanks properly marked with the words "Used Oil"?		
16	Are used batteries and mercury containing lamps stored in their designated area?		
17	Are used batteries and mercury containing lamps marked with accumulation start date?		
18	Are crushed or broken mercury containing lamps contained to prevent release of mercury?		
19	Are leaking batteries contained to prevent release of acid?		

ECRC-08-2965
HEARING EXHIBIT - 00000135

EXHIBIT A
APPENDIX A
ENVIRONMENTAL RULES FOR CONTRACTORS
(continued)

ENVIRONMENTAL FIELD INSPECTION FORM

Chemical/New Product Management	YES	NO
20 Are new products properly stored in labeled containers? • Labeled with contents and appropriate hazard warnings • Containers kept closed • No open top buckets/pails with product • The original manufacturers label intact and readable • MSDS available onsite		
21 Are flammable liquids and aerosols stored in flammable cabinets?		
22 Is the quantity of gasoline storage inside a building < 25 gallons?		
23 Are the "No Smoking" areas free from any evidence of smoking?		
24 Are hazardous materials properly stored away from storm drains or pervious surfaces?		
25 Are storm drains free of hazardous materials? • No staining, discoloration • No odors • No visible sheen		

Air Emissions Management	YES	NO
26 Is the facility area free from any evidence of particulate fallout from stack emissions?		
27 Are fugitive emissions minimized and area sources minimized? (Sandblast curtains, slow vehicle speeds, water truck operating, etc.)		
28 Is the area free from any objectionable odors?		
29 Is excessive noise minimized?		

ECRC-08-2966 HEARING EXHIBIT - 00000136

ENVIRONMENTAL FIELD INSPECTION FORM

Water Quality Management	YES	NO
30 Is the storm-water retention pond (if applicable) properly maintained? Retention ponds should be unclogged, mowed, free of weeds, and structurally sound with all erosion and sedimentation barriers in place and in good condition.		
31 Do the water discharge areas look clean? • Free of foam • No sheen • Each outfall clearly labeled		
32 Is the area free from evidence of industrial wastewater discharging to the ground? (e.g. reverse osmosis reject, etc.)		
33 Are all onsite wells locked?		
34 Are all onsite wells in good shape with no damage?		

Tanks, Pipelines	YES	NO
35 Are the tanks or pipes free from any signs of leakage or spillage?		
36 Are the areas on ground around tanks or piping free from evidence of staining or dying vegetation?		
37 Are oil piping systems properly aligned and are supports/foundations in good condition?		
38 Do all above ground tank structures look sound? • No buckling, cracks, wetting, discoloration, blistering • No significant corrosion • No cracks in base/apron • No signs of settlement • No water accumulation inside dike		
39 Are storage tank/piping release detection systems free of oil? (e.g., double-bottom tank, monitoring wells, etc.)		

	YES	NO

ECRC-08-2967
HEARING EXHIBIT - 00000137

ENVIRONMENTAL FIELD INSPECTION FORM

40	Is the Cathodic Protection working properly? Electrical box shows that amps of current is flowing		
41	Is secondary containment for tanks in good condition? • Concrete secondary containment should be free of cracks or penetrations. • Earthen dikes should be free of erosion, oil stains, trash accumulation or undergrowth. • Are valves in proper location to allow adequate drainage from containment?		
42	Is secondary containment for tanks free of product and water?		
43	Are transformers in proper containment and free of leaks?		

Comments:

Inspector's Signature:

Inspector's Name:

Inspector's Title:

Legend:
NA – Not Applicable

NOTE:
1. **This is not a comprehensive environmental inspection sheet. Other federal, State, and local requirements apply to the facility. Not to be used as a substitute for a full compliance audit.**
2. **This inspection is meant to supplement, and does not replace, routine environmental inspections required by federal regulations, State regulations, or facility plans.**
3. **State specific requirements noted only if different from federal requirements.**
4. **A "No" answer indicates a situation that requires immediate action.**

End

ECRC-08-2968 HEARING EXHIBIT - 00000138

Appendix A – Scope of Work
Exhibit B – Clean Fill Criteria

APPENDIX A
EXHIBIT B
CLEAN FILL CRITERIA

MEMORANDUM

To: Distribution

From:
Date:
Re: **Recommended Clean Fill Screening Process for FPL Utility Properties**

Section 376.30701, Florida Statutes (2003) and the Florida Department of Environmental Protection ("FDEP") rule Chapter 62-780, Florida Administrative Code ("F.A.C.") directs the FDEP to apply the Soil Cleanup Target Levels ("SCTLs") of rule Chapter 62-777, F.A.C. to all contaminated sites where a clean up is required. The SCTLs are conservative default cleanup criteria for approximately 500 constituents many of which are naturally occurring in Florida soils. For FPL, this new soils rule mainly impacts construction projects and the cleanup of contaminated sites.

Furthermore, the SCTLs of Chapter 62-777, F.A.C. may be viewed as an indication of whether or not contamination exists at a site. If a clean up is required due to the discovery of "contamination" the FDEP will require a site to meet residential SCTLs for a "no further action" determination. If a site cannot meet residential soil levels, then some sort of engineering control such as an asphalt cover and fencing will be required in addition to an institutional control such as a deed restriction and an agency permit.

Therefore, future liability for FPL may be created unless fill material brought onto FPL Utility property meets the residential levels for any constituents present. It is advisable that FPL sample and perform analytical testing on representative samples of fill material prior to bringing the fill material onto FPL owned or leased property. In this regard, the following sampling and analysis is recommended prior to bringing clean fill onto any FPL owned or leased property:

Incorporate the Purchase of Clean Fill into the Project and Project Schedule.
This will enable your facility to schedule the physical collection and laboratory analysis of one or more representative samples of the specific fill to be brought on site just prior to delivery. Typical laboratory turn around time is 1-2 weeks. Laboratory analyses may be rushed (1-4 business days) at an additional cost (25-100% markup). This is the best way to ensure that the fill being brought onto FPL property will meet the residential clean soil criteria.

Suggested Screening Process
Soil samples should be collected and analyzed for the clean fill parameters. The standard clean soil parameters are arsenic, barium, cadmium, chromium, lead, selenium, silver, PCBs, and TRPH.

If time permits (i.e., non-rush or pre-qualification samples), it is recommended that the samples first be tested for arsenic as a screening tool. If the arsenic residential SCTL is met, then the laboratory can test the existing soil samples for the remaining clean soil parameters as determined necessary. If time is of the essence (i.e. rush analyses required), samples should be analyzed for all listed parameters at once.

Finally, it should be noted that any fill material that is to be reused on site should undergo the same process, and pass analytical screening for Chapter 62-777, F.A.C. constituents at residential levels.

EXHIBIT A
APPENDIX B
CLEAN FILL CRITERIA
(continued)

RESIDENTIAL SOIL CLEANUP TARGET LEVELS (SCTLs)*
Per Chapter 62-777 F.A.C.
Updated May 16,2005

CONSTITUENT	mg/kg
Arsenic	2.1
Barium	120
Cadmium	82
Chromium	210
Lead	400
Selenium	440
Silver	410
PCBs	0.5
TRPH	460

Note:

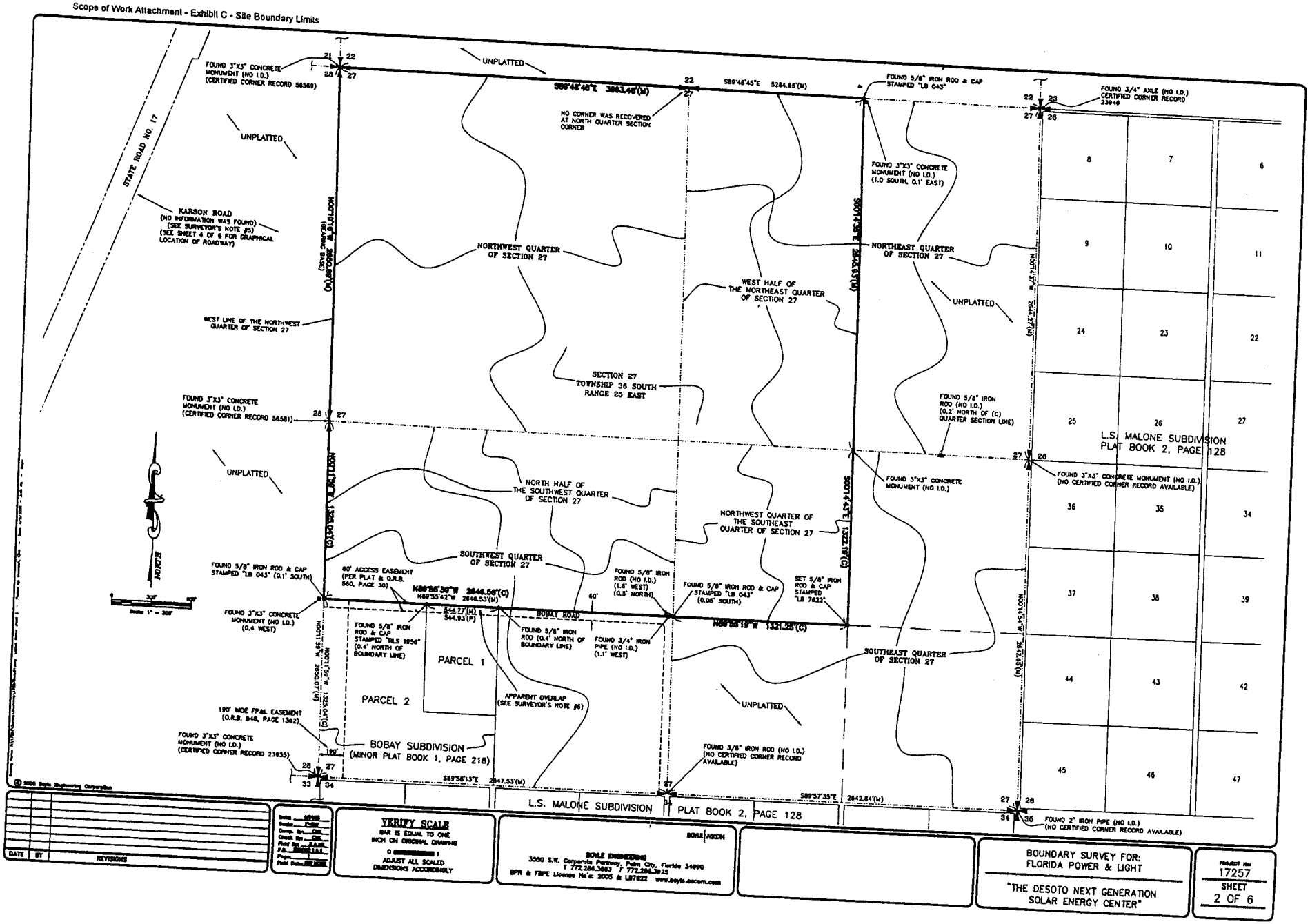
The SCTLs are regulatory-derived values that are subject to periodic review. To ensure that the most up-to-date values are used, consult Chapter 62-777 Florida Administrative Code (F.A.C.), Table 2 (www.dep.state.fl.us/waste/quick_topics/rules/), or contact a JES environmental specialist for assistance.
End

Law/dld/cleanfillmemo

ECRC-08-2971 HEARING EXHIBIT - 00000141

Appendix A – Scope of Work
Exhibit C – Site boundary Limits

Scope of Work Attachment - Exhibit C - Site Boundary Limits



ECRC-08-20173 HEARING EXHIBIT - 00000143

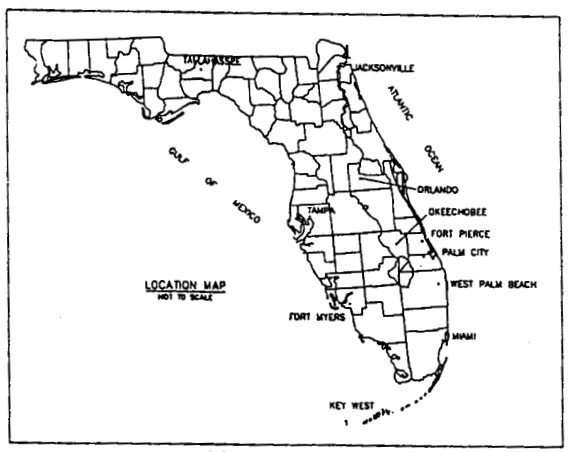
Appendix A – Scope of Work
Exhibit D – Site Development Plan

THE DESOTO NEXT GENERATION SOLAR ENERGY CENTER

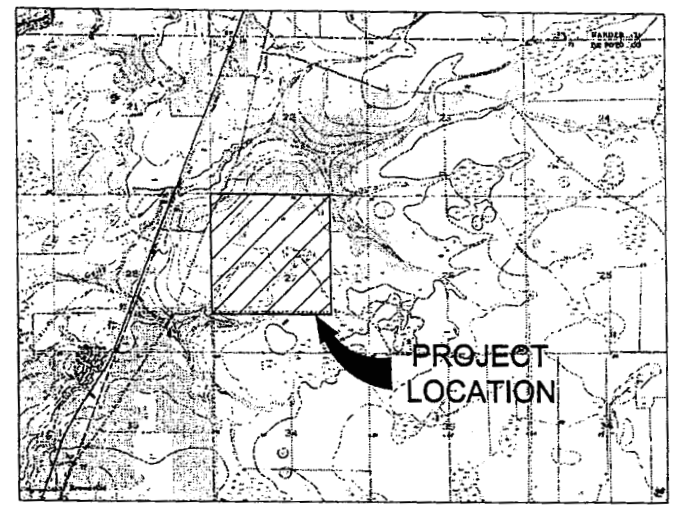
SITE DEVLOPMENT PLAN

FPL

DESOTO COUNTY, FLORIDA
SECTION 27, TOWNSHIP 36S, RANGE 25E



LOCATION MAP



LOCATION SKETCH

SHEET INDEX

SHEET NUMBER	SHEET TITLE/DESCRIPTION
1	COVER SHEET
2	KEY SHEET
3-6	EXISTING CONDITIONS

BOYLE ENGINEERING
421 W. 3rd Street
Deerfield Beach, Florida 33442
T 954-753-8996 F 954-753-8682
FL Engineering Business No. 28-2005

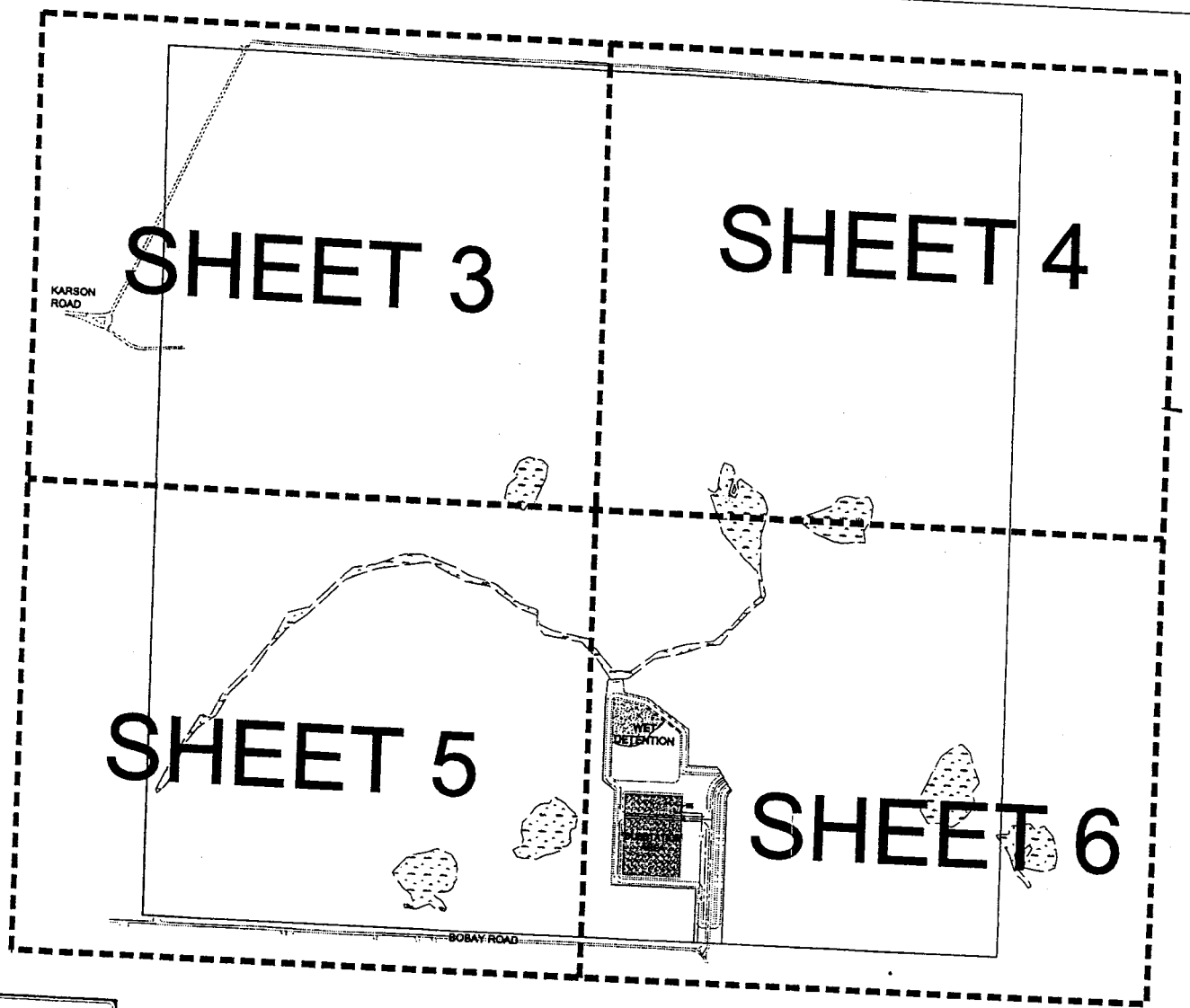
FPL
FLORIDA POWER AND LIGHT COMPANY
THE DESOTO NEXT GENERATION SOLAR ENERGY CENTER
DESOTO COUNTY, FLORIDA

ENGINEER'S SEAL

ECRC-08-2975

HEARING EXHIBIT - 00000145

Scope of Work Attachment - Exhibit D- Site Development Plan



BOYLE ENGINEERING

REVISION

FLORIDA POWER & LIGHT
THE DESOTO NEXT GENERATION SOLAR ENERGY CENTER
PROJECT KEY

SHEET 2 OF 6

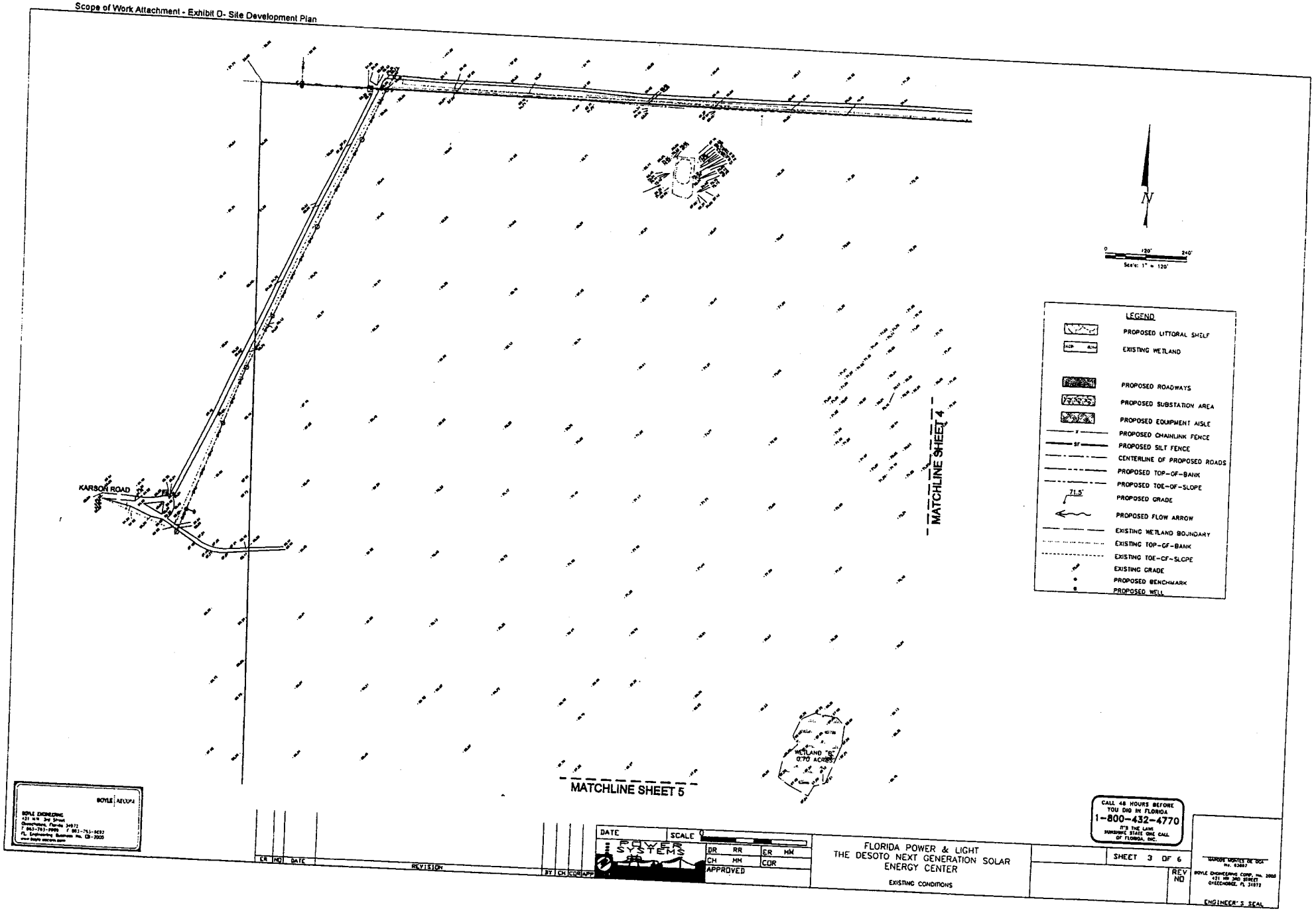
CALL 48 HOURS BEFORE YOU DIG IN FLORIDA 1-800-432-4770

ENGINEER'S SEAL

ECRC-08-2976

HEARING EXHIBIT - 00000146

Scope of Work Attachment - Exhibit D- Site Development Plan



BOYLE ENGINEERING

ER | MD | DATE | REVISION | BY | CH | COR | APP

DATE | SCALE

FLOYER SYSTEMS

DR RR | ER MM
CH MM | COR
APPROVED

FLORIDA POWER & LIGHT
THE DESOTO NEXT GENERATION SOLAR ENERGY CENTER
EXISTING CONDITIONS

CALL 48 HOURS BEFORE YOU DIG IN FLORIDA
1-800-432-4770
IT'S THE LAW!
SUNSHINE STATE ONE CALL OF FLORIDA, INC.

SHEET 3 OF 6

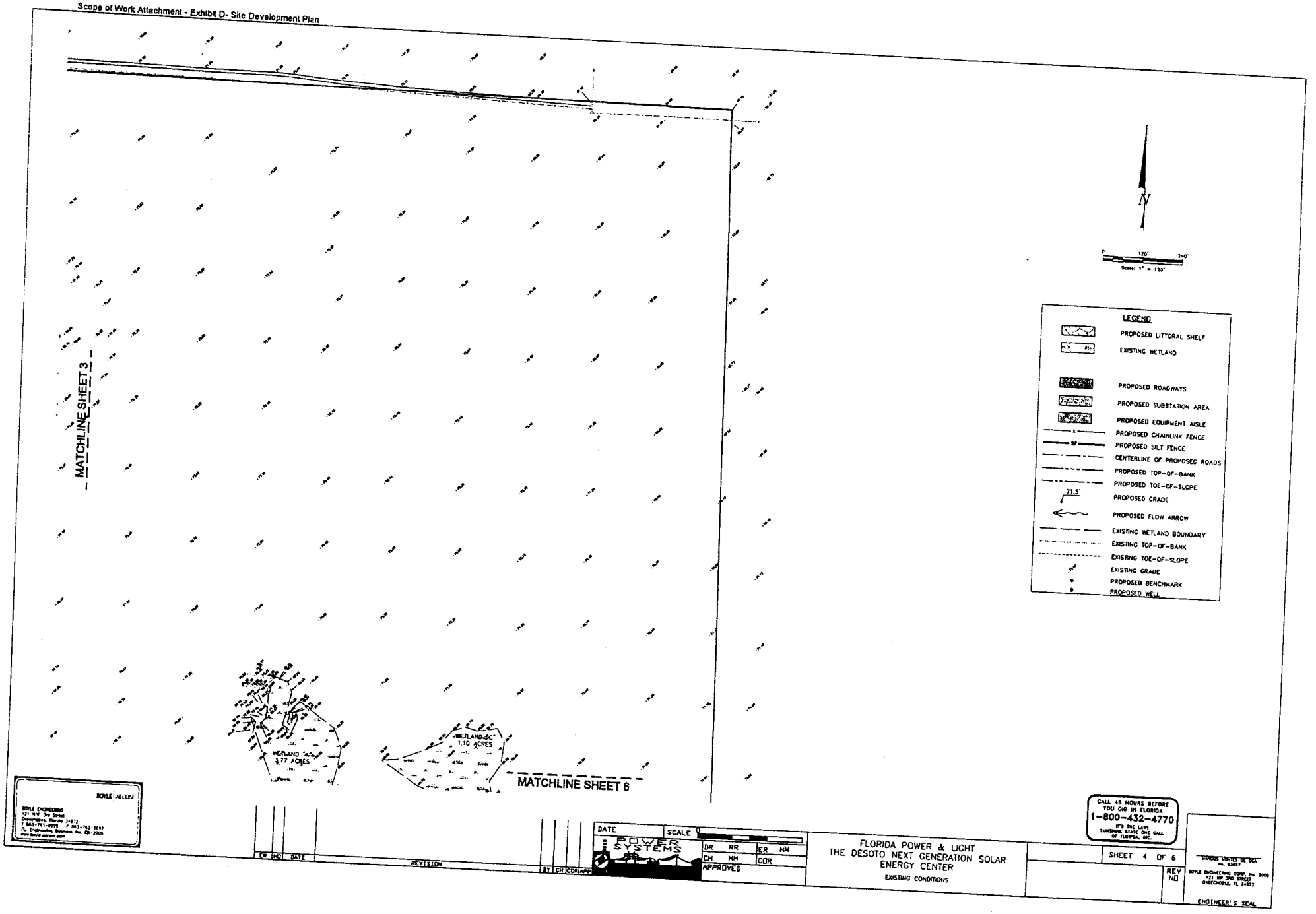
REV NO

ENGINEER'S SEAL

ECRC-08-2977

HEARING EXHIBIT - 00000147

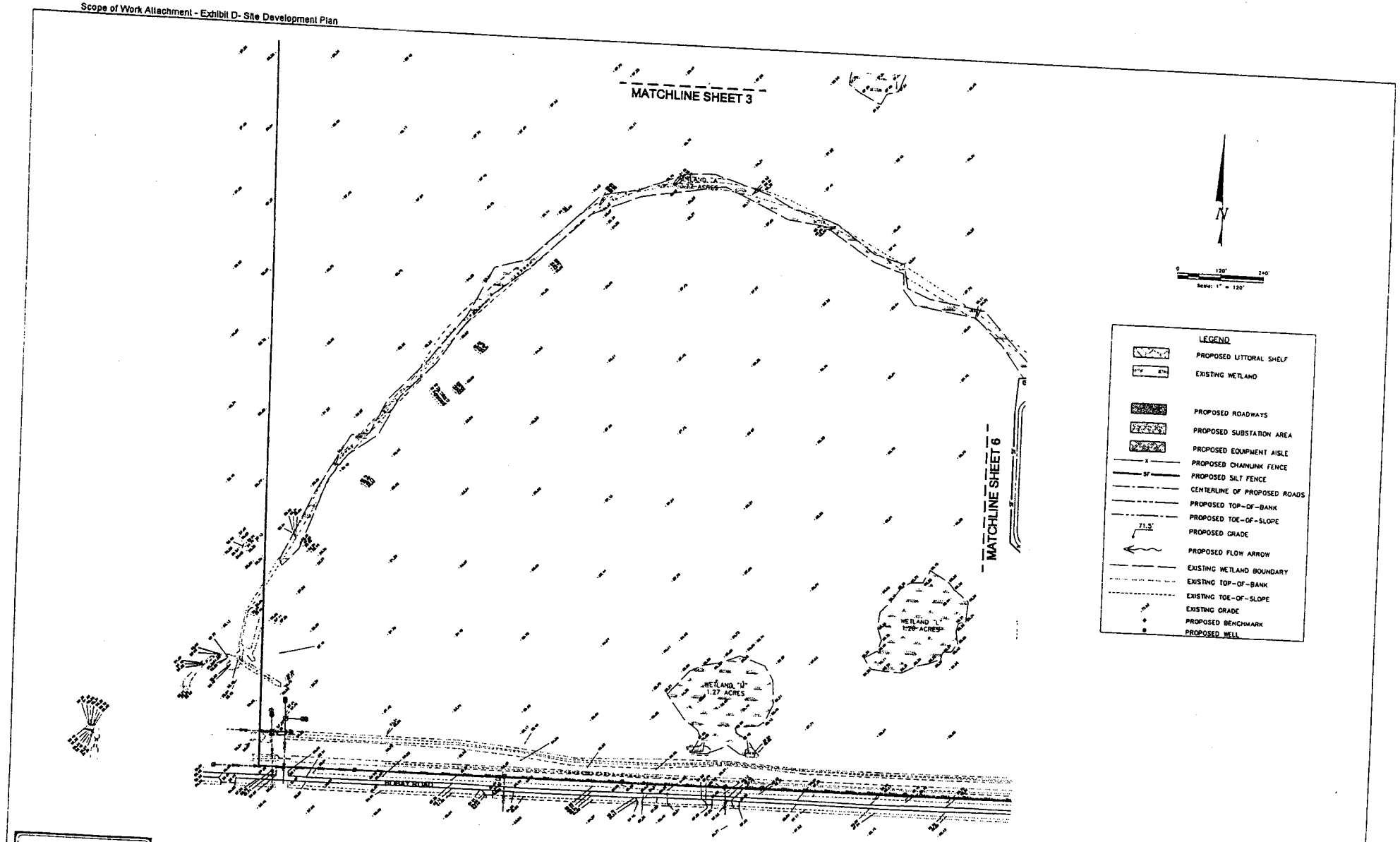
Scope of Work Attachment - Exhibit D- Site Development Plan



ECRC-08-2978

HEARING EXHIBIT - 00000148

Scope of Work Attachment - Exhibit D- Site Development Plan



BOYLE ENGINEERING
121 W. 3rd Street
Okeechobee, Florida 34972
T: 863-763-9998 F: 863-763-9492
FL Engineering Business No. 08-2005
www.boyle-eng.com

ER | MD | DATE | REVISION | BY | CH | COR | APP

DATE | SCALE

POWER SYSTEMS

DR RR ER HM
CH MM COR
APPROVED

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SHEET 5 OF 6

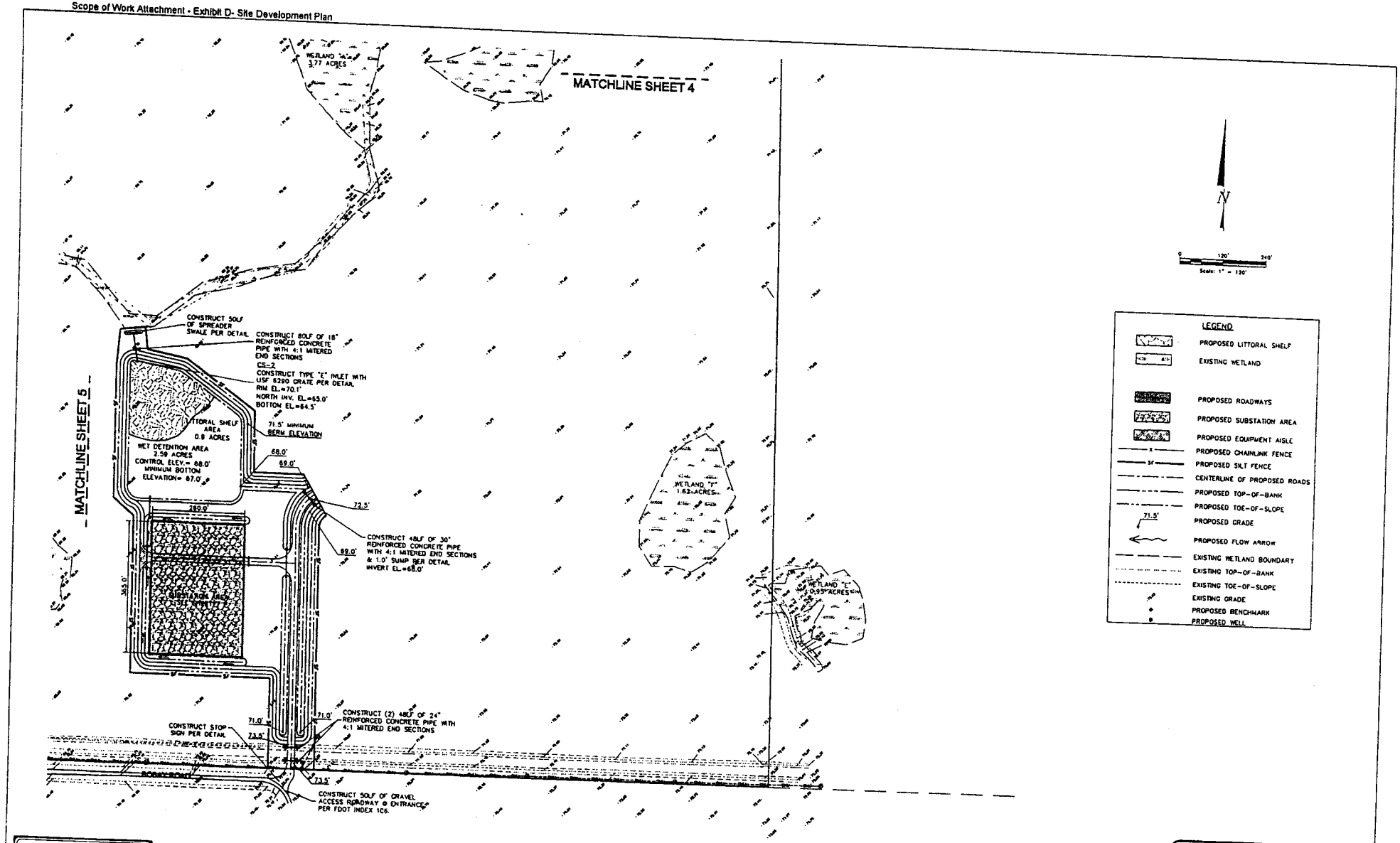
REV NO

ENGINEER'S SEAL

ECRC-08-2979

HEARING EXHIBIT - 00000149

Scope of Work Attachment - Exhibit D- Site Development Plan



BOYLE | AECOM

BOYLE ENGINEERING
421 N.W. 3rd Street
Okeechobee, Florida 34972
863-763-8999 F 863-763-8992
FL Engineering Business No. 28-2005

NO	DATE	REVISION	BY	CH	COR	APP

DATE | SCALE

POWER SYSTEMS

DR	RR	ER	MM
CH	MM	COR	
APPROVED			

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SHEET 6 OF 6

REV NO

MARCOS NUNEZ DE OCA No. 83837

BOYLE ENGINEERING CORP. No. 3000
421 NW 3RD STREET
OKEECHOBEE, FL 34972

ENGINEER'S SEAL

ECRC-08-2980 HEARING EXHIBIT - 00000150

Appendix B – Project Controls Requirements

APPENDIX B
PROJECT CONTROLS REQUIREMENTS

PROJECT CONTROL REQUIREMENTS

1.0 GENERAL PROGRAM REQUIREMENTS

1.1 Provide adequate methods and tools for budget control, scheduling, tracking, trending, and reporting of work in progress for the engineering, procurement and construction activities related to the Project. Owner's intent is to monitor the Agreement at the Project level.

1.2 Identify Contractor's organization.

1.3 Develop and implement a standardized method of invoicing and payment process for work performed.

2.0 SCHEDULE GENERAL REQUIREMENTS

2.1 Bid /Proposal Submittal Requirements

Contractor shall submit a summary schedule with his proposal. This schedule shall be a drafted time-scaled logic diagram that indicates completion of all major activities. Contractor should clearly indicate each contractual milestone submittal date and FPL's deliveries along with Contractors planned completion date, clearly indicating relationships between major activities. Contractor is encouraged to plan for earlier completion dates than the contractual completion dates provided such dates do not interfere with the planned activities of other Contractors or FPL.

2.2 Project Execution Schedule

a. Contractor shall provide an electronic copy (in the most current version of MicroSoft(MS) Project) of Contractor's Construction schedule to FPL within 10 days of Contract award for FPL's approval. The schedule shall be prepared with the understanding that the Contractor's schedule is the Project Master Schedule.

b. Weekly and monthly updates shall be provided to FPL with cut-off dates and submittal dates as determined by FPL. FPL reserves the right of review and approval for the Project Execution Schedule.

c. The schedule shall allow each activity to be assigned to:

- Work Package (No. 1, 2, 3, or 4),
- Area (Unit 3, Unit 4 or Common), and
- Responsibility (Contractor, Engineer, or FPL)

2.3 Schedule Project Progress Reporting (included with Monthly Report)

Within ten (10) days after each calendar month, Contractor shall submit a brief report describing progress from the previous month, an update of the schedule, any commercial or technical issues that remain open, and a matrix of the contract milestones containing the contract date, current scheduled/actual date, and variance between the two.

2.4 Project Schedule Development

a. Contractor's schedule shall be based on FPL's Milestones and Key Dates provided over the course of the Contract.

b. Contractor shall retain responsibility for development and implementation of the schedule covering the scope of work. Contractor retains sole responsibility for meeting schedule Finish Dates.

c. Contractor's Project schedule will include manpower requirements and commodity installation plans. Commodity Installation curves to be developed at a minimum for earthwork, concrete, cable, terminations, panel and support structure installation.

2.5 Project Schedule Integration

a. Contractor shall maintain the project master schedule and integrate other contractor schedules with the mechanical schedule. Also, Contractor shall integrate activities provided by Engineering and FPL for the project into the project master schedule. Contractor schedules shall have a level of detail equivalent to a Level 2 schedule (approximately 100 to 300 activities).

b. The testing, startup of components and systems, and the performance testing shall be integrated by the Contractor into the project master schedule. Contractor shall review the logic to validated correctness of sequence and time durations for all activities in the project master schedule.

3.0 SCHEDULE/PROGRESS MEASUREMENT

3.1 Weekly Progress And Schedule Review

FPL and Contractor representatives shall meet weekly to review the Work progress and update the Work completion schedule. Contractor's representative shall present the following:

a. The current status of their Job Progress.

b. A detailed three week look-ahead schedule

c. Project Milestones current status update and forecast vs. baseline schedule

d. Their current and projected manpower by craft.

e. The material delivery status.

f. The status of drawings and other submittals.

g. Any changes in the Work.

h. The status of "As-Built" Drawings (if required).

i. Problem areas or concerns.

3.2 Progress review meetings will be held weekly at FPL's Jobsite offices.

3.3 Productivity Meetings – Any T&M or Target Price Contractor shall also participate in a weekly productivity meeting with FPL.

3.4 Three Week Look Ahead Schedules

a. Contractor shall develop a 3-week daily work schedule as shown in Attachment 1, Three Week Look Ahead Schedule Example. Generally the schedule shall be submitted to FPL with a copy to all other affected Contractors by the close of business Monday. Any submittals received after 9:00 AM each Tuesday morning shall be considered non-compliant. The exact timing of development may be modified by FPL after commencement of field mobilization.

b. The Three-Week Look Ahead Schedule (3WLAS) will be a bar chart containing activities and durations, area designations, and restraints. Activities shall be planned and scheduled overall consistent with the Project Schedule. The schedule shall be grouped by area.

c. The level of detail required for the 3WLAS shall be determined by the current status of the work and its complexity and coordination with FPL or other Contractors.

d. The key Contractor personnel who will be responsible for working closely with FPL's staff to achieve efficient execution of the Contract shall have the authority to represent Contractor.

3.5 Contractor's three week look-ahead schedule shall:

a. Indicate all planned work and testing that is to be accomplished during the current week and the next two week period all in support of, and in accordance with, Contractor's Construction Schedule.

b. Include major construction equipment requirements

c. Highlight any material or drawing needs from either FPL or Contractor.

d. Reflect the planned and actual activities of the previous week.

e. Include any activities that are required to be accomplished by others that would impact and/or prevent Contractor from starting and/or accomplishing its planned work.

f. Be presented in the level of detail sufficient to direct the efforts of the craft on a day-to-day basis.

4.0 COST REPORTING REQUIREMENTS

4.1 Cost Management Report - Contractor shall provide at a minimum on a bi-weekly basis the Claims, Changes or extra work, delays or accelerations, interferences and the like known to Contractor that have occurred or may be claimed to have occurred since project onset. This information is required to be provided in Microsoft Excel. The report is referred to as the Cost Management Report and will include current status of aforementioned items, initiated dates, dollar exposure amounts (incremental to the executed contract amount), drawing references, subcontractor documentation, etc. as required to establish an understanding of the issues. If there are no known Claims, Changes, etc the Cost Management Report shall still be issued bi-weekly stating NONE. The most recent Cost Management Report shall be attached to each Contractor invoice.

4.2 Contractor shall invoice per the conditions of the contract terms. Additionally at the request of the Owner, Contractor is required to provide an estimate of the next invoice within two business days of the request. It is understood that this request in only an estimate and may be revised with issuance of the formal invoice. .

4.3 Contractor shall develop a Work Breakdown Structure (WBS) assigning cost codes encompassing the entire Scope of Work in an adequate level of detail to provide the outlined reporting requirements contained herein. Ultimately, the WBS should be developed in sufficient detail to permit assignment and allocation of costs to the functional classifications specified in the Owner Property Retirement Unit Catalog.

5.0 MATERIAL STATUS

5.1 Contractor shall maintain an updated Materials List and Shipment Origin and Profile Report for materials procured.

5.2 Contractor shall provide a weekly update of the Materials List and Shipment Origin and Profile Report to FPL.

5.3 Contractor, during the Weekly Progress and Schedule Review Meeting, shall provide a list of shortages and late deliveries that could negatively affect construction and installation if not received in a timely manner.

5.4 Contractor shall provide a composite Materials List and Shipment Origin and Profile Report for all FPL procured materials.

6.0 CONTRACTOR'S DAILY REPORT

6.1 Contractor shall submit to FPL's designated field representative prior to 10:00 a.m. each day, starting from the day Contractor mobilizes at the site, a completed and signed Contractor's Daily Force Report utilizing the form provided as Attachment 2, Daily Force Report, hereto. The Daily Force Report shall contain a listing of Contractor and Contractor manpower, including personnel by responsibility, craft, and remarks concerning the daily field activities.

7.0 TIME AND MATERIALS (T&M) WORK

7.1 Any Contract with a T&M contract or an incentive based contract shall fully report progress and expended man-hours at the individual line item level of FPL's EVMS.

7.2 This includes work performed by any Contractor doing Extra Work Order work on a T&M basis.

8.0 MONTHLY PROGRESS REPORT REQUIREMENTS

8.1 Brief narrative overview of Project status.

8.2 Brief narrative of identified critical issues.

8.3 Brief narrative of short term look ahead activities.

8.4 Updated organization chart for the Project.

8.5 Safety and environmental issues/status.

8.6 Project Milestones current status update and forecast vs. baseline schedule

8.7 Contractor Project schedules shall be updated and submitted in adobe acrobat format (pdf). These schedules shall show current status and the projected completion dates of all Project phases against the current planned schedule.

8.8 An electronic copy (data file) of the most recently updated complete MS Project integrated Project Schedule network.

8.9 Cost Management Report

8.10 Manpower curves (manpower plan with actual and forecast to go over time)

8.11 Progress curves (% Complete progress versus time).

8.12 Construction commodity curves (actual vs. original baseline and current plan) as identified in Section 2.4c above. A variance explanation and/or recovery plan shall be provided by Contractor should progress monitored on fall behind the plan.

8.13 Procurement Status Report. A complete listing of all equipment and materials to be procured by the Contractor, including status of the procurement process (bid, evaluate & award). The information included in this report shall be consistent and support the Project Schedule.

Attachments

Attachment 1 - Three Week Look Ahead Schedule Example

Attachment 2 - Daily Force Report

ECRC-08-2985 HEARING EXHIBIT - 00000155

Project Name Here
Project Number Here
Prepared By:

Exhibit B, Attachment 1 - Three Week Look Ahead Schedule Example

Date: _____

P3 ACTIVITY ID	ACTIVITY DESCRIPTION	Last Week Beginning: Sun	Mon	Tue	Wed	Thu	Fri	Sat	Current Week Beginning: Sun	Mon	Tue	Wed	Thu	Fri	Sat	Week 2 Beginning: Sun	Mon	Tue	Wed	Thu	Fri	Sat	Week 3 Beginning: Sun	Mon	Tue	Wed	Thu	Fri	Sat	P3 Target Completion Date	COMMENTS

Attachment 2 - Daily Force Report

Contract No._____ Date_____

Contractor			Project						
Days/Week			Shifts					Hours/Shift	
Weather			Temperature a.m. p.m.					Work Days on Job	
Personnel	General Foreman	Foreman	Journeyman	Helper	Total	M/Hr Today	Absent	Equipment	No.
Boilermakers								Trucks-Pickup	
Ironworkers-Struct								Trucks-Dump, Flatbed	
Ironworkers-Rebar								Air Compressors	
Millwrights								Tractors	
Oper. Engineers								Crawler-Backhoe	
Testers								Tractor-Backhoe	
Pipefitters								Welding Mach.-Elec	
Carpenters								Welding Mach.-Comb.	
Cement Finishers								Office Trailer	
Laborers								Winch Trucks	
Bricklayers								Cranes Cap	
Electricians								Cranes Cap	
Painters								Cranes Cap	
Insulators								Other	
Sheet Metalworkers									
Roofers									
Clerical Help									
Engineering Asst									
QC Inspectors									
NDE Technicians									
Superintendent									
TOTALS								TOTALS	

COMMENTS:_____

Signature: _____

Appendix C – Critical Milestones and Milestones

APPENDIX C

CRITICAL MILESTONES & MILESTONES
DESOTO

1. Mobilize for Construction	1/1/09
2. Begin Concrete Pedestals	1/16/09
3. Concrete Pedestals 50% Complete	4/1/09
4. Electrical Interconnection Complete	6/15/09
5. Concrete Pedestals Complete	7/1/09
6. Torque Arms Installed Complete	8/1/09
7. PV Modules 100% Delivered	8/5/09
8. Communications Infrastructure for DAS Complete	10/15/09
9. Tracker Erection Complete	11/15/09
10. PV Modules Installed Complete	08/20/09
11. Electrical Construction Complete	10/05/09
12. Provisional Acceptance	12/31/09

Appendix D – Construction and Milestone Payment Schedule

Appendix E – Credit Trigger Event

Appendix E

Credit Trigger Event

1. As provided in Section 1.1.31, a "Credit Trigger Event" shall be deemed to occur if, at the end of the most recently ended fiscal quarter of Contractor, Contractor fails to maintain a Tangible Net Worth of greater than $550,000,000.

2. Upon the occurrence of a Credit Trigger Event and thereafter, the face amount of the Letter of Credit issued pursuant to Section 7.5 shall be adjusted to (or other collateral posted as permitted by Section 7.5 which, together with the then-existing Letter of Credit equal) the stated amount corresponding to the "Level" indicated below including Contractor's Tangible Net Worth at the end of the most recently ended fiscal quarter of Contractor:

Level	Tangible Net Worth	Required Stated Amount Prior to Initial LC Amount Expiration Date	Required Stated Amount After Initial LC Amount Expiration Date
1	Less than or equal to $550,000,000 but greater than $500,000,000	$10,000,000	$6,500,000
2	Less than or equal to $500,000,000 but greater than $450,000,000	$13,750,000	$9,000,000
3	Less than or equal to $450,000,000	$17,500,000	$12,500,000

3. After the Letter of Credit Expiration Date and thereafter until the end of the Warranty Period, upon the occurrence of a Credit Trigger Event, a Letter of Credit shall be issued pursuant to Section 11.8 (or other collateral posted as permitted in Section 11.8) in a stated amount corresponding to the "Level" indicated below including Contractor's Tangible Net Worth at the end of the most recently ended fiscal quarter of Contractor, in addition to the Contractor Parent Guaranty:

Level	Tangible Net Worth	Required Stated Amount After Letter of Credit Expiration Date but Prior to Tenth Anniversary of Final Acceptance Date	Required Stated Amount After Tenth Anniversary of Final Acceptance Date Until the end of all of the Warranty Periods
1	Less than or equal to $550,000,000 but greater than $500,000,000	$500,000	0
2	Less than or equal to $500,000,000 but greater than $450,000,000	$1,000,000	0
3	Less than or equal to $450,000,000 but greater than $400,000,000	$2,000,000	0
4	Less than or equal to $400,000,000	$2,000,000	$500,000

ECRC-08-2993 HEARING EXHIBIT - 00000162

Appendix F – Form of Request for Payment

HEARING EXHIBIT - 00000163

APPENDIX F

FORM OF REQUEST FOR PAYMENT

TO: Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

ATTN:

APPLICATION FOR MILESTONE PAYMENT

FPL Purchase Order No.: _____ DATE: _____

Supplier's Invoice No.: _____

Milestone Number	Milestone Description	Total Activity Value	Activity Value Requested for Payment

Total This Application $_____

ORIGINAL CONTRACT PRICE	$	
Net Change By Change Order	$	
CONTRACT PRICE TO DATE	$	
Less Payments by Owner to Subcontractors	$	
Less Prior Applications for Payment	$	
CURRENT APPLICATION FOR PAYMENT	$	
Less Retention	$	
Net Current Payment	$	
BALANCE OF CONTRACT PRICE	$	

Appendix G – Form of Final Acceptance Certificate

HEARING EXHIBIT - 00000165

APPENDIX G

Form of Final Acceptance Certificate

(Page 1 of 2)

Date: _____

1. Unless otherwise defined herein, the capitalized terms used throughout this certificate shall have the meanings ascribed to same in the Turnkey Engineering, Procurement and Construction Agreement for Solar Photovoltaic Generating Facility dated as of June [__], 2008 (as the same may be amended, modified and supplemented from time to time, the "Agreement") by and between Florida Power & Light Company, a Florida corporation ("FPL") and SunPower Corporation, Systems, a Delaware Corporation ("Contractor").

2. Contractor certifies and represents that the following statements are true as of the date of delivery hereof to FPL:

   a) The Contractor has satisfied all of the requirements for the achievement of Final Acceptance in accordance with the Agreement.

   b) Contractor has delivered this form, completed except for signature by FPL, to FPL's duly authorized representative referred to in Section 4.11 of the Agreement on the above date.

3. The person signing below is authorized to submit this form to FPL for and on behalf of Contractor.

SunPower Corporation, Systems,
as Contractor

By: _____
Name: _____
Title: _____

ECRC-08-2997 HEARING EXHIBIT - 00000166

Appendix G

Form of Final Acceptance Certificate
(Page 2 of 2)

FPL to cross through one (1) of the following statements:

A. FPL agrees that Final Acceptance has been achieved. This Certificate was received by FPL on the date first written above and is effective as of that date.

B. FPL does not agree that Final Acceptance has been achieved by the Contractor due to the following:

_____

_____

_____

_____

FPL:

The person signing below is authorized to sign the Final Acceptance Certificate for and on behalf of FPL.

By: _____ Date: _____
Name: _____
Title: _____

ECRC-08-2998 HEARING EXHIBIT - 00000167

Appendix H – Form of Contractor Certificate for Partial Waiver of Liens

APPENDIX H

FORM OF CONTRACTOR CERTIFICATE FOR PARTIAL WAIVER OF LIENS

This CONTRACTOR'S PARTIAL LIEN WAIVER AND RELEASE ("Contractor's Partial Lien Waiver and Release") is made by SunPower Corporation, Systems, a Delaware corporation ("Contractor"), on behalf of itself, its successors and assigns, and those acting by or through any of the foregoing, for and in consideration of the sum of [AMOUNT OF PARTIAL PAYMENT REQUEST] DOLLARS ($[_____]) (the "Progress Payment") and other good and valuable consideration, in hand paid, the receipt and sufficiency of which are hereby acknowledged, as full payment on account of all labor, services, materials, equipment and other work performed through the ___ day of _____, 200_ (the "Release Date"), for Florida Power & Light Company, a Florida corporation ("Owner"), in connection with the construction of a solar photovoltaic electric generation facility, and all services and utilities related thereto, in De Soto County, Florida (such facility, together with the property on which such facility is located, the "Project"), pursuant to that certain TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT FOR SOLAR PHOTOVOLTAIC GENERATING FACILITY, dated as of June [__], 2008, between Owner and Contractor, as the same may be amended from time to time (as the same may be amended, modified and supplemented from time to time, the "Agreement").

Solely with respect to the Work performed by the Contractor relating to the Project on or prior to the Release Date, the Contractor does hereby unconditionally and irrevocably waive, release, remise, relinquish and quit-claim (collectively, the "Release") all actions, claims, demands, liens, lien rights and claims of lien, of any kind whatsoever (collectively, "Claims"), which Contractor ever had or now has, known or unknown, against the Project or against Owner, its parents, subsidiaries and affiliates, at all tiers, and its and their insurers, sureties, employees, officers, directors, representatives, shareholders, agents, and all parties acting for any of them (collectively, the "Released Entities"), including, without limitation, all claims related to, in connection with, or arising out of, all facts, acts, events, circumstances, changes or extra work, constructive or actual delays or accelerations, interferences and the like, which have occurred or may be claimed to have occurred. The foregoing Release shall only be effective with respect to Claims arising in connection with the portion of the work performed by Contractor prior to the Release Date.

The Contractor warrants and represents, solely with respect to all Work completed through the Release Date that (a) the Contractor has not assigned or pledged any rights or claims in any amount due or to become due from Owner in connection with the Project; (b) payment has been or will be made to all subcontractors, laborers and material suppliers, at all tiers, for all labor, services, materials and equipment furnished by or through the Contractor for the Project, including all payroll taxes and contributions required to be made; (c) no claims from subcontractors, vendors, mechanics or materialmen against the Released Entities have been submitted to Contractor with respect to the Project or remain unsatisfied as of the date hereof; (d) no mechanics' or materialmen's liens have been filed with respect to the Project that have not been discharged or for which a bond has not been posted in accordance with the Agreement; and (e) payment of all amounts due has been made to all consultants, employees, subcontractors, laborers and material suppliers, at all tiers, and all other entities, for all labor, services, materials and equipment furnished by or through Contractor for the Project, including, without limitation, all payroll taxes and contributions required to be made and all wages, overtime pay, premium pay, holiday pay, sick pay, personal leave pay, severance pay, fees, fringe benefits, commissions

ECRC-08-3000 HEARING EXHIBIT - 00000169

and reimbursable expenses required to be paid and all deductions for dues, fees or contributions required to be made in connection with all collective bargaining agreements in existence, if any, which affect any worker(s) providing services for the Project.

Solely with respect to all Work for the Project completed through the Release Date, the Contractor agrees to defend, indemnify and hold the Released Entities harmless from and against any and all actions, causes of action, losses or damages of whatever kind, including, without limitation, reasonable attorneys' fees and costs in arbitration and at the pre-trial, trial and appellate levels, which the Released Entities may suffer by reason of (a) any claim made against the Project or any of the Released Entities relating to labor, services, materials or equipment furnished by or through the Contractor in connection with the Project, or (b) any breach of any representation or warranty made by the Contractor to Owner in connection with the Project, including the representations and warranties included herein, any false statement made in this Contractor's Partial Lien Waiver and Release or any misrepresentation or omission made to Owner by the Contractor.

The Contractor acknowledges and agrees that (a) Owner is relying upon the representations and warranties made herein as a material inducement for Owner to make the Progress Payment to the Contractor; (b) this Contractor's Partial Lien Waiver and Release is freely and voluntarily given by the Contractor, and the Contractor has had the advice of counsel in connection herewith and is fully informed as to the legal effects of this Contractor's Partial Lien Waiver and Release, and the Contractor has voluntarily accepted the terms herein for the consideration recited above; and (c) the tendering of the Progress Payment by Owner and the receipt of the Progress Payment and the execution of this Contractor's Partial Lien Waiver and Release by the Contractor shall not, in any manner whatsoever, release the Contractor from (i) its continuing obligations with respect to the completion of any work at the Project that remains incomplete, including warranty work or guaranty work, or the correction of defective or non-conforming work; (ii) any contractual, statutory or common law obligations of the Contractor with respect to the Released Entities in connection with the Project; or (iii) any other obligations of the Contractor with respect to Released Entities in connection with the Project.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK;
SIGNATURES APPEAR ON FOLLOWING PAGE.]

Dated this ___day of _____, 200__.

SUNPOWER CORPORATION, SYSTEMS:

WITNESSES:

_____
Name:_____

_____
Name:_____

By:_____
Name:_____
Title:_____
Address:_____
_____
_____

NOTARIAL ACKNOWLEDGMENT

STATE OF _____)
) **ss:**
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 200__, by _____, the _____ of SunPower Corporation, Systems, a Delaware corporation, who executed the foregoing instrument on behalf of said corporation, and who is personally known to me or who produced _____ as identification.

_____
Name: _____
Notary Public, State of [Florida]
[If notarized in a State other than Florida, Signatory shall comply with the notary requirements of such State.]
Commission No._____
My Commission expires: _____
(Seal)

Appendix H-1 – Form of Subcontractor Certificate for Partial Waiver of Liens

HEARING EXHIBIT - 00000172

APPENDIX H-1

FORM OF SUBCONTRACTOR CERTIFICATE FOR PARTIAL WAIVER OF LIENS

This SUBCONTRACTOR'S PARTIAL LIEN WAIVER AND RELEASE is made by [_____], a [_____] (the "Releasor"), subcontractor to SunPower Corporation, Systems, a Delaware corporation ("Contractor"), on behalf of Releasor, its successors and assigns, and those acting by or through any of the foregoing, for and in consideration of the sum of Ten and No/100 DOLLARS ($10.00) and other good and valuable consideration, in hand paid, the receipt and sufficiency of which are hereby acknowledged, as full payment on account of all labor, services, materials, equipment and other work furnished through the ___ day of _____, 200_ (the "Release Date"), for work in connection with the construction of a solar photovoltaic electric generation facility, and all services and utilities related thereto, in De Soto County, Florida (such facility, together with the property on which such facility is located, the "Project") by Contractor on behalf of Florida Power & Light Company, a Florida corporation ("Owner").

Solely with respect to the work performed by the Releasor on or prior to the Release Date in connection with the Project, the Releasor does hereby unconditionally and irrevocably waive, release, remise, relinquish and quit-claim (collectively, the "Release") all actions, claims, demands, liens, lien rights and claims of lien, of any kind whatsoever (collectively, "Claims"), which Releasor ever had or now has, known or unknown, against the Project or against Owner or Contractor, their partners, parents, subsidiaries and affiliates, at all tiers, and their insurers, sureties, employees, officers, directors, representatives, shareholders, agents, and all parties acting for any of them (collectively, the "Released Entities"), including, without limitation, all claims related to, in connection with, or arising out of, all facts, acts, events, circumstances, changes or extra work, constructive or actual delays or accelerations, interferences and the like, which have occurred or may be claimed to have occurred. The foregoing Release shall only be effective with respect to Claims arising in connection with the portion of the work performed by Releasor prior to the Release Date.

The Releasor warrants and represents, solely with respect to all work by Releasor completed for the Project through the Release Date, that (a) the Releasor has not assigned or pledged any rights or claims in any amount due or to become due from Contractor in connection with the Project; (b) payment has been or will be made to all of its subcontractors, laborers and material suppliers, at all tiers, for all labor, services, materials and equipment furnished by or through the Releasor for the Project, including all payroll taxes and contributions required to be made; (c) no claims from any of its subcontractors, vendors, mechanics or materialmen against the Released Entities in connection with the Project have been submitted to Releasor with respect to the Project or remain unsatisfied as of the date hereof; (d) no mechanics' or materialmen's liens have been filed with respect to the Project that have not been discharged; and (e) payment of all amounts due has been made to all consultants, employees, subcontractors, laborers and material suppliers, at all tiers, and all other entities, for all labor, services, materials and equipment furnished by or through Releasor for the Project, including, without limitation, all payroll taxes and contributions required to be made and all wages, overtime pay, premium pay, holiday pay, sick pay, personal leave pay, severance pay, fees, fringe benefits, commissions and reimbursable expenses required to be paid and all deductions for dues, fees or contributions required to be made in connection with all collective bargaining agreements in existence, if any, which affect any worker(s) providing services for the Project.

Solely with respect to all work by Releasor in connection with the Project completed through the Release Date, the Releasor agrees to defend, indemnify and hold the Released Entities harmless from and against any and all actions, causes of action, losses or damages of whatever kind, including, without limitation, reasonable attorneys' fees and costs in arbitration and at the pre-trial, trial and appellate levels, which the Released Entities may suffer by reason of (a) any claim made against the Project or any of the Released Entities relating to labor, services, materials or equipment furnished by or through the Releasor, or (b) any breach of any representation or warranty made by the Releasor to the Released Entities, including the representations and warranties included herein, any false statement made in this Subcontractor's Partial Lien Waiver and Release, or any misrepresentation or omission made to the Released Entities by the Releasor.

The Releasor acknowledges and agrees that (a) the Contractor and Owner are relying upon the representations and warranties made herein as a material inducement for the Contractor to make payment to the Releasor; (b) this Subcontractor's Partial Lien Waiver and Release is freely and voluntarily given by the Releasor and the Releasor has had the advice of counsel in connection herewith and is fully informed as to the legal effects of this Subcontractor's Partial Lien Waiver and Release and the Releasor has voluntarily accepted the terms herein for the consideration recited above; and (c) the tendering of payment by the Contractor and the receipt of payment and the execution of this Subcontractor's Partial Lien Waiver and Release by the Releasor shall not, in any manner whatsoever, release the Releasor from (i) its continuing obligations with respect to the completion of any work at the Project that remains incomplete, including warranty work or guaranty work, or the correction of defective or non-conforming work; (ii) any contractual, statutory or common law obligations of the Releasor with respect to any of the Released Entities in connection with the Project; or (iii) any other obligations of the Releasor with respect to any of the Released Entities in connection with the Project.

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SIGNATURES APPEAR ON FOLLOWING PAGE.]

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Dated this ___day of _____, 200__.

WITNESSES:

_____
Name:_____

_____
Name:_____

Subcontractor:

By: _____
Name:_____
Title:_____
Address:_____
_____
_____

NOTARIAL ACKNOWLEDGMENT

STATE OF _____)
) **ss:**
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 200__, by _____, the _____ of_____, a _____, who executed the foregoing instrument on behalf of said corporation, and who is personally known to me or who produced _____ as identification.

_____
Name: _____
Notary Public, State of [Florida] **[If notarized in a State other than Florida, Signatory shall comply with the notary requirements of such State.]**
Commission No._____
My Commission expires: _____
(Seal)

ECRC-08-3006 HEARING EXHIBIT - 00000175

Appendix I – Form of Contractor Parent Guaranty

APPENDIX I

FORM OF CONTRACTOR PARENT GUARANTY

THIS GUARANTY (this "Guaranty"), dated as of June [__], 2008, is issued by SunPower Corporation, a Delaware corporation (the "Guarantor"), in favor of Florida Power & Light Company, a Florida corporation ("Owner").

Pursuant to Section 11.8 of Turnkey Engineering, Procurement and Construction Agreement for Solar Photovoltaic Generating Facility dated as of June [__], 2008, (as the same may be amended, modified and supplemented from time to time, the "Agreement") by and between SunPower Corporation, Systems, a Delaware corporation, and of which Guarantor is the parent (the "Subsidiary"), and Owner, Guarantor hereby covenants and agrees with Owner as follows:

Section 1. Definitions. Capitalized terms used herein and not otherwise defined shall have their respective meanings as set forth in the Agreement.

Section 2. Guaranty.

(a) Guaranty. Guarantor hereby irrevocably and unconditionally guarantees, as primary obligor and not merely as surety, to and for the benefit of Owner and any successor or permitted assignee of Owner under the Agreement, the full and prompt payment and performance by Subsidiary of each and every payment and performance obligation of Subsidiary arising under the Agreement (whether such obligation presently exists or is created, incurred or arising from time to time hereafter), including, without limitation, the payment when due of any indemnities, refunds and liquidated damages payable at any time under the Agreement, all amounts payable to Owner pursuant to Section 3(a) of this Guaranty and the performance of the Work (the "Guaranteed Obligations"). Guarantor further agrees that if Subsidiary shall fail to pay or perform in full when due all or any part of the Guaranteed Obligations, Guarantor will immediately pay or perform the same upon demand.

(b) Absolute Guaranty. Subject to Section 2(e) of this Guaranty, Guarantor agrees that its obligations under this Guaranty are irrevocable, absolute, independent and unconditional and shall not be affected by any circumstance that constitutes a legal or equitable discharge of a guarantor or surety other than payment and performance in full of the Guaranteed Obligations. In furtherance of the foregoing and without limiting the generality thereof, Guarantor agrees, subject to the other terms and conditions hereof, as follows:

(i) this Guaranty is a guaranty of payment and performance and not of collectibility;

(ii) Owner may from time to time, without notice or demand and without affecting the validity or enforceability of this Guaranty or giving rise to any limitation, impairment or discharge of Guarantor's liability hereunder, (A) create new obligations or liabilities under the Agreement or renew, extend, accelerate or otherwise change the time, place, manner or terms of the Guaranteed Obligations or otherwise amend or modify the Agreement or change the terms of the Guaranteed Obligations or any part thereof, (B) settle, compromise, release or discharge, or accept or refuse any offer of payment of, or substitutions for, the Guaranteed Obligations or any agreement relating thereto and/or subordinate the payment of the same to the payment of any other obligations, (C) request or accept other guaranties of the Guaranteed Obligations, (D) take and hold security for the payment of this Guaranty or the Guaranteed Obligations, (E) substitute, release, exchange, compromise, subordinate or modify, with or without consideration, any security for payment of the Guaranteed Obligations, any other guaranties of the Guaranteed Obligations, or any other obligation of any Person with respect to the Guaranteed Obligations, (F) enforce and apply any security now or hereafter held by or for the benefit of Owner in respect of this Guaranty or the Guaranteed Obligations and direct the order or manner of sale thereof, or exercise any other right or remedy that Owner may have against any such security, as Owner in its discretion may determine consistent with the Agreement and any applicable security agreement, notwithstanding that such action operates to impair

or extinguish any right of subrogation, reimbursement, indemnification or contribution or any other right or remedy of Guarantor against Subsidiary or any other guarantor of the Guaranteed Obligations or any other guaranty of or security for the Guaranteed Obligations, (G) assign the Guaranteed Obligations in whole or in part to the extent provided in the Agreement, or (H) exercise any other rights available to Owner under the Agreement, at law or in equity; and

(iii) this Guaranty and the obligations of Guarantor hereunder shall be valid and enforceable and shall not be subject to any limitation, impairment or discharge for any reason (other than payment in full of the Guaranteed Obligations and as otherwise set forth in this Guaranty), including, without limitation, the occurrence of any of the following, whether or not Guarantor shall have had notice or knowledge of any of them: (A) any failure to assert or enforce, or agreement not to assert or enforce, or the stay or enjoining, by order of court, by operation of law or otherwise, of the exercise or enforcement of, any claim or demand or any right, power or remedy with respect to the Guaranteed Obligations or any agreement relating thereto, or with respect to any other guaranty of or security for the payment of the Guaranteed Obligations; (B) any waiver, amendment or modification of, or any consent to departure from, any of the terms or provisions of the Agreement or any agreement or instrument executed pursuant thereto or of any other guaranty or security for the Guaranteed Obligations; (C) the Guaranteed Obligations, or any agreement relating thereto, at any time being found to be illegal, invalid or unenforceable in any respect; (D) the personal or corporate incapacity of any Person; (E) the bankruptcy, receivership or insolvency of Subsidiary or any other Person, or the discharge of Subsidiary's or any other Person's obligations in any bankruptcy, receivership or similar proceeding; (F) any merger or consolidation of Subsidiary or Guarantor into or with any other Person, or any sale, lease or transfer of any of the assets of Subsidiary or Guarantor to any other Person, (G) any change in the ownership of any interests of Subsidiary or any change in the relationship between Subsidiary and Guarantor, or any termination of such relationship or (H) any other act or thing or omission, or delay to do any other act or thing, which may or might in any manner or to any extent vary the risk of Guarantor as an obligor in respect of the Guaranteed Obligations.

(c) Payments. All payments made by Guarantor hereunder shall be made without set-off or counterclaim and without any deduction or withholding for any reason, except as expressly provided to the contrary in the Agreement. All payments hereunder shall be made in U.S. dollars in immediately available funds.

(d) Reinstatement. Notwithstanding anything to the contrary contained herein, this Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time any payment, or part thereof, under this Guaranty is rescinded or must otherwise be returned or restored by Owner upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of, or similar event affecting, Subsidiary or Guarantor, or any substantial part of either's property, or otherwise, all as though such payment had not been made.

(e) Defenses. Notwithstanding anything herein to the contrary, Guarantor specifically reserves to itself all rights, counterclaims and other defenses that the Subsidiary is or may be entitled to arising from or out of the Agreement, except for any counterclaims or defenses arising out of the bankruptcy, insolvency, dissolution or liquidation of the Subsidiary, the lack of power or authority of the Subsidiary to enter into the Agreement or to perform its obligations thereunder, or the lack of validity or enforceability of the Subsidiary's obligations under the Agreement or any transaction thereunder.

Section 3. Other Provisions of the Guaranty.

(a) Costs and Expenses. The prevailing party in any action or proceeding shall be entitled to recover from the other party all of its reasonable costs and expenses incurred in connection with such action or proceeding, including reasonable attorneys' fees and costs at the trial court and all appellate levels.

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(b) Waivers by Guarantor. Guarantor hereby waives for the benefit of Owner, to the maximum extent permitted by Applicable Laws:

(i) all of the following: (A) notice of acceptance hereof or of any matter referred to in Section 2 hereof , (B) all presentments and demands for payment, (C) notices of default, nonpayment, protests, notices of protest, notices of dishonor and notices of any renewal, extension or modification of the Guaranteed Obligations or any agreement related thereto, (D) notice of any action taken or omitted to be taken by Owner in reliance hereon and any and all notices which may or might be lawfully waived by Guarantor, (E) any requirement that Owner be diligent or prompt in making demands hereunder or in giving notice to Guarantor of any default by Subsidiary, or asserting any other rights of Owner hereunder against Subsidiary, (F) any requirement that Owner protect, secure, perfect or insure any security interest or lien or any property subject thereto, (G) any bankruptcy, insolvency, reorganization, arrangement, adjustment, composition, liquidation or similar event of either Subsidiary or Guarantor that might constitute a defense to any payment required under the Agreement or hereunder, (H) any event, occurrence or other circumstance which might otherwise constitute a legal or equitable discharge of a surety or guarantor, including any defense based upon any law, rule or regulation which provides that the obligation of a surety must not be greater or more burdensome than the obligation of the principal, (I) any defense arising by reason of the incapacity, lack of authority or any disability or other defense of Subsidiary including, without limitation, any defense based on or arising out of the lack of validity or the unenforceability of the Guaranteed Obligations or any agreement or instrument relating thereto or by reason of the cessation of the liability of Subsidiary from any cause other than payment in full of the Guaranteed Obligations or termination of this Guaranty in accordance with its terms, (J) any defense arising out of any election by Owner to foreclose on any security held by or for the benefit of Owner pursuant to one or more judicial or nonjudicial sales, even though such election operates to impair or extinguish any right of subrogation, reimbursement, indemnification or contribution or any other right or remedy of Guarantor against Subsidiary or any other guarantor of the Guaranteed Obligations or any other guaranty of or any security for the Guaranteed Obligations, (K) the benefit of any statute of limitations affecting Guarantor's liability hereunder or the enforcement hereof, and (L) any rights to set-offs, recoupments and counterclaims;

(ii) any requirement, and any right to require, as a condition of payment by Guarantor, (A) that any right or power be exercised or any action be taken against either Subsidiary, any other guarantor or any collateral security for the Guaranteed Obligations, (B) that Owner proceed against or exhaust any security held from Subsidiary or any other person, or (C) that Owner pursue any other remedy in Owner's power whatsoever, and Guarantor waives the right to have the property of Subsidiary first applied to the discharge of the Guaranteed Obligations. Owner may, at its election, exercise any right or remedy it may have against Subsidiary or any security now or hereafter held by Owner. Guarantor waives (D) any principles or provisions of Applicable Laws, statutory or otherwise, that are or might be in conflict with the terms of this Guaranty and any defense based on the discharge of Subsidiary by operation of Applicable Laws, notwithstanding any intervention or omission by Owner, including any defenses or benefits that may be derived from or afforded by Applicable Laws (whether now in effect or hereafter adopted) that limit the liability of or exonerate guarantors or sureties, and (E) any defense based on or arising out of the absence, impairment or loss of any right of subrogation, reimbursement, indemnification or contribution or any other right or remedy of Guarantor against Subsidiary or any such security, whether resulting from such election by Subsidiary or otherwise; and

(iii) all rights and benefits under (A) provisions of Applicable Laws purporting to (1) reduce the obligation of a surety or guarantor upon the acceptance by a creditor of anything in partial satisfaction of an obligation, (2) exonerate a surety or guarantor if by any act of the creditor, without the consent of the surety or guarantor, the original obligation of the principal is altered in any respect, or the remedies or rights of the creditor against the principal, in respect thereto, are in any way impaired or suspended (it being expressly understood and agreed that Owner may compromise, settle, alter, extend, waive, amend, suspend or surrender any Guaranteed Obligation or

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any right or remedy with respect thereto without notice to or consent by Guarantor and without affecting Guarantor's obligations hereunder), (3) exonerate the surety or guarantor to the extent that the creditor does not proceed against the principal, or pursue any other remedy in the creditor's power which the surety or guarantor cannot pursue, and which would lighten the surety's or guarantor's burden, and (4) reduce a surety's or guarantor's obligations in proportion to the principal obligation, and (B) provisions of Applicable Laws requiring or permitting creditors or lienors to marshal assets or liens; it being the intention hereof that Guarantor shall remain liable as principal, to the extent set forth in this Guaranty, for so long as this Guaranty shall remain in effect, notwithstanding any act, omission or thing which might otherwise operate as a legal or equitable discharge of the Guarantor other than the payment in full of the Guarantee Obligations.

(c) **Deferral of Subrogation**. Until such time as all of the Guaranteed Obligations have been fully satisfied, notwithstanding any payment made by Guarantor hereunder or the receipt of any amounts by Owner with respect to the Guaranteed Obligations: (i) Guarantor (on behalf of itself, its successors and assigns, including any surety or guarantor) agrees not to exercise any all rights it may have at law or in equity (including, without limitation, any law subrogating Guarantor to the rights of Owner) to seek subrogation, contribution, indemnification, or any other form of reimbursement from Subsidiary, any other guarantor, or any other Person now or hereafter primarily or secondarily liable for any of the Guaranteed Obligations of Subsidiary to Owner, for any disbursement made by Guarantor under or in connection with this Guaranty or otherwise; and (ii) Guarantor agrees not to obtain any benefit of, and any right to participate in, any security, whether real or personal property, now or hereafter held by Owner for the Guaranteed Obligations.

Section 4. Representations and Warranties of Guarantor. Guarantor hereby represents and warrants to Owner as follows:

(a) Guarantor is duly organized, validly existing and in good standing under the laws of its jurisdiction of organization;

(b) Guarantor has full power, authority and legal right to execute and deliver this Guaranty and all other instruments, documents and agreements required by the provisions of this Guaranty to be executed, delivered and performed by Guarantor, and to perform its obligations hereunder and thereunder;

(c) The execution, delivery and performance of this Guaranty and all other instruments, documents and agreements required by the provisions of this Guaranty to be executed, delivered and performed by Guarantor have been duly authorized by all necessary company action on the part of Guarantor;

(d) This Guaranty has been duly executed and delivered by Guarantor and constitutes the legal, valid and binding obligation of Guarantor, enforceable against it in accordance with its terms; and

(e) All necessary action has been taken under Applicable Laws to authorize the execution, delivery and performance of this Guaranty. No governmental approvals or other consents, approvals, or notices of or to any Person are required in connection with the execution, delivery, performance by Guarantor or the validity or enforceability, of this Guaranty.

Section 5. Notices. All notices and other communications provided for hereunder must be in writing to be effective and shall be deemed to be delivered and received (a) if personally delivered or if delivered by courier service, when actually received by the party to whom notice is sent, (b) if delivered by facsimile, on the first Business Day following the day transmitted, or (c) if delivered by mail (whether actually received or not), at the close of business on the third Business Day following the day when placed in the mail, postage prepaid, certified or registered, addressed to the appropriate party hereto, at the address and/or facsimile numbers of such party set forth below (or at such other address as such party may designate by written notice to the other party in accordance with this Section:

(a) If to Guarantor:

SunPower Corporation
3939 North First Street
San Jose, California 95134
Attention: Chief Financial Officer
Facsimile: (408) 739-7713

(b) If to Owner:

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Attention: [_____]
Facsimile: [_____]

The addresses and facsimile numbers of either party for notices given pursuant to this Guaranty may be changed by means of a written notice given to the other party at least fifteen (15) Business Days prior to the effective date of such change.

Section 6. Miscellaneous Provisions.

(a) Waiver; Remedies Cumulative. No failure on the part of Owner to exercise, and no delay on the part of Owner in exercising, any right or remedy, in whole or in part hereunder shall operate as a waiver thereof. No single or partial exercise of any right or remedy shall preclude any other or further exercise thereof or the exercise of any other right or remedy. No waiver by Owner shall be effective unless it is in writing and such writing expressly states that it is intended to constitute such waiver. Any waiver given by Owner of any right, power or remedy in any one instance shall be effective only in that specific instance and only for the purpose for which given, and will not be construed as a waiver of any right, power or remedy on any future occasion. In addition, Guarantor may not claim that Owner could have avoided or mitigated, in any manner or through any action, the damages resulting from a default of Subsidiary under the Agreement. The rights and remedies of Owner herein provided are cumulative and not exclusive of any rights or remedies provided by law.

(b) Successors and Assigns. This Guaranty shall be binding upon the successors of Guarantor and shall inure to the benefit of Owner and its successors and permitted assigns. Guarantor shall not assign or transfer all or any party of its rights or obligations hereunder without the prior written consent of Owner. Any purported assignment or delegation without such written consent shall be null and void. Owner may assign its rights and obligations hereunder to any assignee of its rights under the Agreement permitted in accordance with the Agreement. No other Persons shall be a third-party beneficiary of, or otherwise benefit by, this Guaranty or have or acquire any rights by reason of this Guaranty.

(c) Amendment. This Guaranty may not be modified, amended, terminated or revoked, in whole or in part, except by an agreement in writing signed by Owner and Guarantor.

(d) Termination and Release. Subject to Section 2(d) hereof, this Guaranty shall remain in effect until the payment in full of the Guaranteed Obligations. No release of this Guaranty shall be valid unless executed by Owner and delivered to Guarantor.

(e) GOVERNING LAW; JURISDICTION.

(i) THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER OR PURSUANT TO THIS GUARANTY SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF FLORIDA, WITHOUT REGARD FOR

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ANY PRINCIPLES OF CONFLICTS OF LAW THAT WOULD DIRECT OR PERMIT THE APPLICATION OF THE LAW OF ANY OTHER JURISDICTION.

(ii) THE EXCLUSIVE VENUE FOR ANY ACTION OR PROCEEDING RELATED TO THIS GUARANTY SHALL BE, AND GUARANTOR HEREBY SUBMITS TO THE JURISDICTION OF, THE FEDERAL COURTS OF THE UNITED STATES FOR THE SOUTHERN DISTRICT OF FLORIDA, PROVIDED, THAT IF FOR WHATEVER THE REASON THE FEDERAL COURTS OF THE UNITED STATES FOR THE SOUTHERN DISTRICT OF FLORIDA WILL NOT OR CANNOT HEAR SUCH ACTION OR PROCEEDING, THE EXCLUSIVE VENUE FOR ANY ACTION OR PROCEEDING RELATED TO THIS GUARANTY SHALL BE, AND GUARANTOR HEREBY SUBMITS TO THE JURISDICTION OF, THE COURTS OF THE STATE OF FLORIDA IN PALM BEACH COUNTY. THE PARTIES IRREVOCABLY WAIVE ANY OBJECTION WHICH ANY OF THEM MAY NOW OR HEREAFTER HAVE TO THE BRINGING OF ANY SUCH ACTION OR PROCEEDING IN SUCH RESPECTIVE JURISDICTIONS,

(iii) GUARANTOR WAIVES ANY OBJECTION WHICH IT MAY HAVE TO THE LAYING OF VENUE OF ANY SUCH SUIT, ACTION OR PROCEEDING IN ANY OF SUCH COURTS AND ANY CLAIM THAT ANY SUCH SUIT, ACTION OR PROCEEDING HAS BEEN BROUGHT IN AN INCONVENIENT FORUM, INCLUDING ANY OBJECTION TO THE LAYING OF VENUE BASED ON THE GROUNDS OF FORUM NON CONVENIENS AND ANY OBJECTION BASED ON THE GROUNDS OF LACK OF IN PERSONAM JURISDICTION.

(iv) GUARANTOR IRREVOCABLY CONSENTS TO SERVICE OF PROCESS OUT OF ANY OF THE AFOREMENTIONED COURTS IN ANY MANNER PERMITTED BY SUCH COURTS, INCLUDING REGISTERED OR CERTIFIED MAIL, POSTAGE PREPAID, TO GUARANTOR AT ITS ADDRESS SET FORTH IN THIS AGREEMENT (OR AS OTHERWISE NOTICED TO THE OTHER PARTY PURSUANT TO SECTION 5), IN EACH CASE SUCH SERVICE TO BECOME EFFECTIVE THIRTY (30) DAYS AFTER SUCH MAILING.

(v) GUARANTOR AGREES THAT FINAL JUDGMENT IN ANY SUCH ACTION OR PROCEEDING SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN ANY OTHER JURISDICTION BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY LAW.

(vi) NOTHING IN THIS SECTION SHALL AFFECT THE RIGHT OF OWNER (A) TO SERVE LEGAL PROCESS IN ANY OTHER MANNER PERMITTED BY LAW, OR (B) TO BRING ANY SUIT, ACTION OR PROCEEDING AGAINST THE UNDERSIGNED OR ITS PROPERTIES IN THE COURTS OF ANY OTHER JURISDICTIONS.

(vii) GUARANTOR AND OWNER EACH HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, SUIT OR COUNTERCLAIM ARISING IN CONNECTION WITH THIS GUARANTY. THIS PROVISION IS A MATERIAL INDUCEMENT FOR GUARANTOR AND OWNER TO ENTER INTO THIS GUARANTY.

(f) **Survival**. All representations and warranties made in this Guaranty and in any other instrument, document, and agreement delivered pursuant hereto or in connection herewith shall survive the execution and delivery of this Guaranty.

(g) **Severability**. If any provision of this Guaranty is held to be illegal, invalid, or unenforceable under present or future laws, such provision shall be fully severable; this Guaranty shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part of this Guaranty; and the remaining provisions of the Guaranty shall remain in full force and effect and shall not be affected by the illegal, invalid, or unenforceable provision or by its severance from the Guaranty. Furthermore, in lieu of such illegal, invalid or unenforceable provision, there shall

be added automatically as a part of this Guaranty a provision as similar in its terms to such illegal, invalid or unenforceable provision as may be possible and be legal, valid and enforceable.

(h) Information. Owner shall have no obligation to disclose or discuss with Guarantor its assessment, or Guarantor's assessment, of Subsidiary's financial condition. Guarantor acknowledges and agrees that it has adequate means to obtain information from Subsidiary on a continuing basis concerning Subsidiary's financial condition and its ability to perform its obligations under the Agreement, and Guarantor assumes the responsibility for being and keeping informed of Subsidiary's financial condition and of all circumstances bearing upon the risk of nonpayment of the Guaranteed Obligations. Guarantor hereby waives and relinquishes any duty on the part of Owner to disclose any matter, fact or thing relating to the business, operations or conditions of Subsidiary now known or hereafter known by Owner.

(i) Counterparts. Guarantor and Owner acknowledge and agree that this Guaranty may be executed in multiple counterparts, and transmitted via telecopy, each such counterpart (whether transmitted via telecopy or otherwise), when executed, shall constitute an integral part of one and the same agreement.

This Guaranty has been duly executed on behalf of the Guarantor by its authorized officer as of the date first written above.

SUNPOWER CORPORATION

By:_____
Name: _____
Title: _____

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Appendix J – Option Pricing

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Appendix J

Option Pricing

FPL may elect to purchase any, all or none of the options listed below, subject to maximum annual quantities, in the column entitled "Option Description" (each an "Option", collectively the "Options"). The price of each of the Options for the Project is set forth in the column entitled "Option Price", which price shall be paid at the same percentages upon achievement of the same milestones set forth in the Construction and Payment Milestone Schedule attached to the Agreement.[1] In the event FPL notifies Contractor of its exercise of a given Option, upon FPL's delivery of a Final Notice to Proceed with respect to the associated commencement of Work, an additional Letter of Credit shall be issued pursuant to the requirements of Section 7.5 with a face amount equal to five percent (5%) of the related Option Price through the final acceptance date, after which the face amount of such Letter of Credit shall equal two and one-half percent (2.5%) of the Option Price until the expiration of such Letter of Credit on the second anniversary of the final acceptance date.

The notice to proceed date (s), critical milestone dates, guaranteed provisional acceptance and final acceptance dates, construction and milestone payment dates, and termination payment dates shall be mutually agreed by the Parties at the time of Option exercise. In order to choose any of the Options, FPL must notify Contractor on or before the date set forth in the column entitled "Option Date". In the event FPL exercises an Option set forth herein, such Option(s) shall thereafter be considered part of the Work, and Contractor shall promptly commence and diligently pursue to completion such additional Work.

Option Description	Option Price	Option Date
1) 25 MW (net) capacity increase.	$134,100,590	July 1, 2009 (for 2010 install)
2) 5 MW (net) capacity increase. FPL may exercise this option up to five times, for a total of 25 MW (net) capacity increase.	$27,244,759 for each 5 MW option selected	July 1, 2009 (for 2010 install)
3) 25 MW (net) capacity increase.	$128,608,566	January 1, 2010 (for 2011 install)
4) 5 MW (net) capacity increase. FPL may exercise this option up to five times, for a total of 25 MW (net) capacity increase.	$26,129,369 for each 5 MW option selected	January 1, 2010 (for 2011 install)

[1] The Option Price assumes the Driven Pier Design (as defined in Section 7.1 of the Agreement) is implemented. In the event that Contractor elects not to effect the Driven Pier Design, the Parties will mutually agree on appropriate revisions to the Option Price.

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Materials Cost Adjustments:

Indexing for Steel

Parties agree that the prices for Options #3 and 4 above will be adjusted in the event of an increase or decrease of more than 5% in the price of steel on The Steel Index (www.thesteelindex.com) between the (i) average index price in dollars/per short ton using "US Domestic Hot Rolled-Coil" of the of the prior four (4) week period preceding the original date the EPC agreement is executed and (ii) the average index price of the prior four (4) week period preceding the date that the Option is exercised. If The Steel Index is not available for such purposes, the Parties shall use the American Metal Market (www.amm.com) instead. For purposes of the foregoing price adjustment steel shall be deemed to represent 8% of the total Option Price. The price shall be adjusted by the proportional increase or decrease (as applicable) of the index price beyond the 5% tolerance band (e.g. an increase of 9% in the index shall cause 8% of the Option Price to increase by 4% (i.e. 9%-5%=4%). For purposes of clarification, only the 8% steel portion of the Option Price increases 4%. For example, if FPL exercises the 25 MW Option for a 2011 installation at $128,608,566 and the index increases 9%, the Option Price shall increase $409,600.

Appendix K – Module Warranty

SUNPOWER

SUNPOWER LIMITED WARRANTY FOR PV MODULES

SPR-315E-xxx-x, SPR-300E-xxx-x, SPR-305-xxx-x, SPR-290-xxx-x, SPR-230-xxx-x, SPR-225-xxx-x, SPR-220-xxx-x, SPR-217-xxx-x, SPR-215-xxx-x, SPR-210-xxx-x, SPR-205-xxx-x, SPR-200-xxx-x, SPR-90-xxx-x ("xxx-x" define product variants)

1. Limited Product Warranty – Ten (10) Year Repair, Replacement or Refund Remedy

SunPower Corporation with offices at 3939 North First Street, San Jose, CA 95134 ("SunPower") warrants that for ten (10) years from the date of delivery, its Photovoltaic modules ("PV modules") shall be free from defects in materials and workmanship under normal application, installation, use and service conditions. If the PV modules fail to conform to this warranty, then for a period ending ten (10) years from date of delivery to the original end-customer ("the Customer"), SunPower will, at its option, either repair or replace the product, or refund the purchase price as paid by the Customer ("Purchase Price"). The repair, replacement or refund remedy shall be the sole and exclusive remedy provided under the Limited Product Warranty and shall not extend beyond the ten (10) year period set forth herein. This Limited Product Warranty does not warrant a specific power output, which shall be exclusively covered under clause 2 hereinafter (Limited Power Warranty).

2. Limited Power Warranty

a) SunPower additionally warrants: If, within twelve (12) years from date of delivery to the Customer any PV module(s) exhibits a power output less than 90% of the Minimum Peak Power[1] as specified at the date of delivery in SunPower's Product datasheet, provided that such loss in power is determined by SunPower (at its sole and absolute discretion) to be due to defects in material or workmanship SunPower will replace such loss in power by either providing to the Customer additional PV modules to make up such loss in power or by providing monetary compensation equivalent to the cost of additional PV modules required to make up such loss in power or by repairing or replacing the defective PV modules, at the option of SunPower

b) SunPower additionally warrants: If, within twenty five (25) years from date of delivery to the Customer any PV module(s) exhibits a power output less than 80% of the Minimum Peak Power[1] as specified at the date of delivery in SunPower's Product datasheet, provided that such loss in power is determined by SunPower (at its sole and absolute discretion) to be due to defects in material or workmanship SunPower will replace such loss in power by either providing to the Customer additional PV modules to make up such loss in power or by providing monetary compensation equivalent to the cost of additional PV modules required to make up such loss in power or by repairing or replacing the defective PV modules, at the option of SunPower.

3. Exclusions and limitations

a) Warranty claims must in any event be filed within the applicable Warranty period.
b) Warranty claims may only be made by, or on the behalf of, the original end customer or a person to whom title has been transferred for the PV Modules.
c) The Limited Warranties do not apply to any of the following:
    1. PV modules which in SunPower's absolute judgment have been subjected to: misuse, abuse, neglect or accident; alteration, improper installation, application or removal (including but not

[1] *"Minimum Peak Power" = Peak power minus the Peak power tolerance (as specified in SunPower's Product datasheet). "Peak power" is the power in peak watts that a PV module generates at STC (Standard Test conditions: Irradiance of 1000 W/m², light spectrum AM 1.5g and a cell temperature of 25 degrees C)*

limited to installation, application or removal by any party other than a SunPower authorized dealer; non-observance of SunPower's installation, users and/or maintenance instructions; repair or modifications by someone other than an approved service technician of SunPower; power failure surges, lightning, flood, fire, accidental breakage or other events outside SunPower's control.

2. Cosmetic defects stemming from normal wear and tear of PV module materials.
3. PV modules installed in locations, which in SunPower's absolute judgment may be subject to direct contact with salt water.

d) The Limited Warranties do not cover any transportation costs for return of the PV modules, or for reshipment of any repaired or replaced PV modules, or cost associated with installation, removal or reinstallation of the PV modules.

e) When used on a mobile platform of any type, the Limited Power Warranty, applying to any of the PV modules shall be limited to twelve (12) years as per the provisions of clause 2(a) hereof.

f) Warranty claims will not apply if the type or serial number of the PV modules is altered, removed or made illegible.

4. Limitation of Warranty Scope

SUBJECT TO THE LIMITIATIONS UNDER APPLICABLE LAW, THE LIMITED WARRANTIES SET FORTH HEREIN ARE EXPRESSLY IN LIEU OF AND EXCLUDE ALL OTHER EXPRESS OR IMPLIED WARRANTIES, INCLUDING BUT NOT LIMITED TO WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR PARTICULAR PURPOSE, USE, OR APPLICATION, AND ALL OTHER OBLIGATIONS OR LIABILITIES ON THE PART OF SUNPOWER, UNLESS SUCH OTHER WARRANTIES, OBLIGATIONS OR LIABILITIES ARE EXPRESSLY AGREED TO IN WRITING SIGNED AND APPROVED BY SUNPOWER. SUNPOWER SHALL HAVE NO RESPONSIBILITY OR LIABILITY WHATSOEVER FOR DAMAGE OR INJURY TO PERSONS OR PROPERTY OR FOR OTHER LOSS OR INJURY RESULTING FROM ANY CAUSE WHATSOEVER ARISING OUT OF OR RELATED TO THE PRODUCT, INCLUDING, WITHOUT LIMITATION, ANY DEFECTS IN THE MODULE, OR FROM USE OR INSTALLATION. UNDER NO CIRCUMSTANCES SHALL SUNPOWER BE LIABLE FOR INCIDENTAL, CONSEQUENTIAL OR SPECIAL DAMAGES, HOWSOEVER CAUSED. LOSS OF USE, LOSS OF PROFITS, LOSS OF PRODUCTION, LOSS OF REVENUES ARE THEREFORE SPECIFICALLY BUT WITHOUT LIMITATION EXCLUDED.

SUNPOWER'S AGGREGATE LIABILITY, IF ANY, IN DAMAGES OR OTHERWISE, SHALL NOT EXCEED THE PURCHASE PRICE PAID TO SUNPOWER BY THE CUSTOMER, FOR THE UNIT OF PRODUCT OR SERVICE FURNISHED OR TO BE FURNISHED, AS THE CASE MAY BE, WHICH GAVE RISE TO THE WARRANTY CLAIM.

SOME STATES DO NOT ALLOW LIMITATIONS ON IMPLIED WARRANTIES OR THE EXCLUSION OF DAMAGES SO THE ABOVE LIMITATIONS OR EXCLUSIONS MAY NOT APPLY TO YOU.

5. Obtaining Warranty Performance

If you feel you have a justified claim covered by this Limited Warranty, immediately notify the (a) Installer, who sold the PV-modules, or (b) any authorized SunPower distributor, of the claim in writing, or (c) send such notification to SunPower Corporation, 3939 North First Street, San Jose, CA 95134, directly. In addition, please enclose evidence of the date of delivery of the PV module. If applicable, your installer or distributor will give advice on handling the claim. If further assistance is required, please write to SunPower for instructions. The return of any PV-modules will not be accepted unless prior written authorization has been given by SunPower.

Appendix L – O&M Manual

HEARING EXHIBIT - 00000190

Appendix M – FPL Permits

DeSoto Solar Project
List of Permits/Authorizations/Action Items

APPENDIX M
FPL Permits

	Task	Responsible Agency	Responsible Party	Target Completion Date	Comments
1	Environmental Resource Permit	FDEP	FPL	11/1/08	ACOE not required because no impact to wetlands.
2	Conduct Threatened and Endangered (T&E) Species Survey	FDEP	FPL	5/28/08	Complete.
3	Gopher Tortoise Relocation	FFWCC	FPL	10/15/08	Need final site layout before relocation, if needed.
4	Conduct a Phase 1 cultural assessment on areas that have not been previously surveyed	SHPO	FPL	8/4/08	
5	Federal, State and Local easements	site specific	FPL	TBD	
6	Determination of 'no hazard to air navigation'	FAA	FPL	7/30/08	
7	Spill Prevention Control and Counter Measures (SPCC) Plan	EPA	FPL	TBD	Post Construction if needed.
8	Conditional Use Permit	County	FPL	5/8/08	Complete.
9	Site Plan Approval	County	FPL	10/15/08	Need final site layout from Contractor.
10	Zoning/Land Use Amendment	County	FPL	5/8/08	Complete.
11	Water well permits (consumptive)	County or WMD	FPL	12/30/08	N/A for Construction. Needed for Operation.
12	Submit Wetland Jurisdictional Determination Application	FDEP	FPL	5/1/08	Complete.

ECRC-08-3149 HEARING EXHIBIT - 00000192

Appendix N – Termination Payment Schedule

APPENDIX N
Schedule of Termination of Values

Termination Dollars Due	% Owed of Total Contract Price	If Terminated After
$0	0.00%	6/1/2008
$0	0.00%	7/1/2008
$692,231	0.50%	8/1/2008
$1,384,463	1.00%	9/1/2008
$3,115,041	2.25%	10/1/2008
$4,153,388	3.00%	11/1/2008
$4,153,388	3.00%	12/1/2008
$8,306,776	6.00%	1/1/2009
$13,844,627	10.00%	2/1/2009
$17,998,016	13.00%	3/1/2009
$24,920,329	18.00%	4/1/2009
$31,842,643	23.00%	5/1/2009
$67,838,674	49.00%	6/1/2009
$89,990,078	65.00%	7/1/2009
$112,141,482	81.00%	8/1/2009
$124,601,646	90.00%	9/1/2009
$131,523,960	95.00%	10/1/2009
$131,523,960	95.00%	11/1/2009
$138,446,274	100.00%	12/1/2009
$138,446,274	100.00%	1/1/2010

*Termination values are based on a Contract Price of $138,446,274. If the Contract Price is adjusted pursuant to the Agreement, the termination values shall be adjusted to the product of the adjusted Contract Price and the applicable "% Owed of Total Contract Price" for a given termination value.

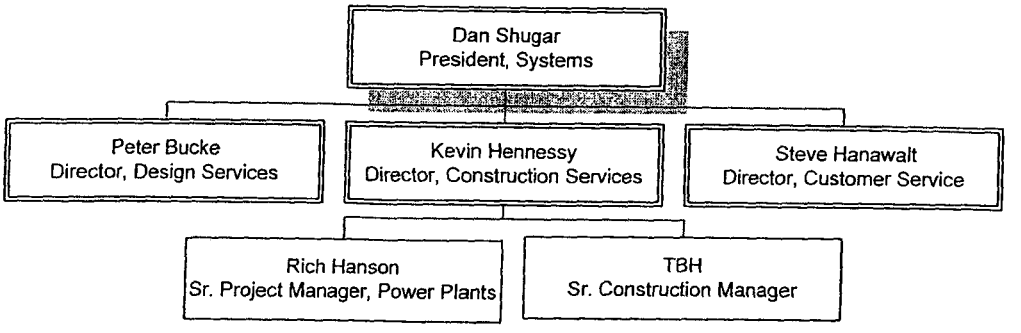
Note:
The Termination Payment due and payable upon a termination on or prior to January 1, 2009, shall be the applicable amount provided for under the column "Termination Dollars Due" for a termination on or after a date specified under the column "If Terminated After" less the aggregate amount of the Contract Price paid by FPL to Contractor as of such date. The Termination Payment due and payable upon a termination after January 1, 2009 shall be the greater of: (1) the applicable amount provided for under the column "Termination Dollars Due" for a termination on or after a date specified under the column "If Terminated After" less the aggregate amount of the Contract Price paid by FPL to Contractor as of such date and (2) the aggregate amount of outstanding approved and unpaid Requests for Payment made pursuant to the Agreement which entitle Contractor to payment in accordance with the Construction and Milestone Payment Schedule. If FPL issues a Notice to Proceed before January 1, 2009, the parties will consider, in their sole discretion, amending by mutual agreement the dates stated in this Appendix N.

Appendix O – Project Management Team

HEARING EXHIBIT - 00000195

APPENDIX O

Project Management Team



TBH – To be hired, subject to the approval requirements of Section 3.12.1 of the Agreement

Biographical Information:

Daniel S. Shugar, President, SunPower Systems

Mr. Shugar leads Supply Chain, Manufacturing, Product Development, and Project Engineering and Construction. Since January 1996, Mr. Shugar has overseen the installation of over 200 MW of solar PV projects. He has been active in solar power since 1988. Mr. Shugar has a B.S. in Electrical Engineering from Rensselaer Polytechnic University, and an MBA from Golden Gate University in San Francisco.

Kevin Hennessy, Director, Construction Services

Mr. Hennessy is a Professional Engineer with over 25 years of commercial construction experiences. He has extensive knowledge of design and construction methods of all types of building systems and has developed projects all over the globe. He is responsible for the Design and Construction groups in the Systems Group at SunPower. This team has been responsible for implementation of the largest Solar PV Energy projects throughout the world, including several projects over 20MW's. Kevin is a California licensed Civil Engineer and has a M.S. in Civil Engineering from Stanford University.

Peter Buecke, Director Design Services

Mr. Buecke is an architect who has led the design and construction division for several national home builders. He is responsible for all activities related to the design and engineering of large ground-mounted and roof-top solar projects. He has over 20 years of experience on project planning with success in setting and meeting project design milestones. He has a B.S in Design from the College of Architecture at Arizona State University.

Steve Hanawalt, Director, Customer Service

Mr. Hannawalt leads the Customer Service and O&M Group for SunPower Systems. His energy facility operations and management experience includes start-up engineering, performance engineering, operations management, and asset optimization. Prior to joining SunPower, he was Vice President of

Plant Optimization at Calpine Corporation, a large independent power producer. In that capacity his group provided the 25,000 MW fleet with system commissioning services, performance and reliability engineering, and real-time performance monitoring and diagnostic services. Plant Optimization provided the performance, reliability, and cost structure inputs to System Dispatch to optimize the economic dispatch of the generating units. Mr. Hanawalt received his B.S. in Mechanical Engineering from the University of California, Berkeley and is currently pursuing his MBA.

Rich Hanson, Senior Project Manager

Mr. Hanson has been involved as a project manager of utility size power plants since joining SunPower Corp . Most recently he was responsible for completing a 14 MW ground mounted tracking system at Nellis Air Force Base in Las Vegas, NV. Prior to joining SunPower, Rich was Director of Construction for a Construction Management firm in the California Central Valley, specializing in design/build management of medical office buildings, airport construction, and regional shopping centers.

Appendix P – Legal Description of Property Site

APPENDIX P

LEGAL DESCRIPTION OF PROPERTY SITE

A tract of land located in Desoto County and more particularly described as follows:

The northwest quarter and the west half of the northeast quarter and the north half of the southwest quarter and the southeast quarter of Section 27, Township 36 South, Range 25 East; And the south half of the northeast quarter and the west half of the southwest quarter and the southeast quarter of Section 26, Township 36 South, Range 25 East; And Section 35, Township 36 South, Range 25 East; And the west half of the northeast quarter of Section 2, Township 37 South, Range 25 East.

APPENDIX Q

Intentionally Deleted

HEARING EXHIBIT - 00000200

Appendix R – Form of Contractor Certificate for Final Waiver of Liens

HEARING EXHIBIT - 00000201

APPENDIX R

FORM OF CONTRACTOR CERTIFICATE FOR FINAL WAIVER OF LIENS

This CONTRACTOR'S FULL LIEN WAIVER AND RELEASE ("Contractor's Full Lien Waiver and Release") is made by SunPower Corporation, Systems, a Delaware corporation ("Contractor"), on behalf of itself, its successors and assigns, and those acting by or through any of the foregoing, for and in consideration of [AMOUNT OF FINAL PAYMENT REQUEST] DOLLARS ($[_____]) and other good and valuable consideration, in hand paid, the receipt and sufficiency of which are hereby acknowledged, as full and final payment on account of all labor, services, materials, equipment and other work performed for Florida Power & Light Company ("Owner"), in connection with the construction of a solar photovoltaic electric generation facility, and all services and utilities related thereto, in De Soto County, Florida (such facility, together with the property on which such facility is located, the "Project"), pursuant to that certain TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT FOR SOLAR PHOTOVOLTAIC GENERATING FACILITY, dated as of June [__], 2008, between Owner and Contractor, as the same may be amended from time to time (the "Agreement").

Contractor does hereby unconditionally and irrevocably waive, release, remise, relinquish and quit-claim all actions, claims, demands, liens, lien rights and claims of lien, of any kind whatsoever, which Contractor ever had, now has, or may have in the future, known or unknown, against the Project or against Owner, its parents, subsidiaries and affiliates, at all tiers, and its and their insurers, sureties, employees, officers, directors, representatives, shareholders, agents, and all parties acting for any of them related to or arising from the Project (collectively, the "Released Entities"), including, without limitation, all claims related to, in connection with, or arising out of, all facts, acts, events, circumstances, changes or extra work, constructive or actual delays or accelerations, interferences and the like, which have occurred or may be claimed to have occurred.

The Contractor warrants and represents that (a) the Contractor has not assigned or pledged any rights or claims in any amount due or to become due from Owner related to or arising from the Project; (b) payment has been or will be made to all subcontractors, laborers and material suppliers, at all tiers, for all labor, services, materials and equipment furnished by or through the Contractor for the Project, including all payroll taxes and contributions required to be made; (c) no claims from subcontractors, vendors, mechanics or materialmen against the Released Entities have been submitted to Contractor with respect to the Project or remain unsatisfied as of the date hereof; (d) no mechanics' or materialmen's liens have been filed with respect to the Project that have not been discharged or for which a bond has not been posted in accordance with the Agreement; (e) payment of all amounts due has been made to all consultants, employees, subcontractors, laborers and material suppliers, at all tiers, and all other entities, for all labor, services, materials and equipment furnished by or through Contractor for the Project, including, without limitation, all payroll taxes and contributions required to be made and all wages, overtime pay, premium pay, holiday pay, sick pay, personal leave pay, severance pay, fees, fringe benefits, commissions and reimbursable expenses required to be paid and all deductions for dues, fees or contributions required to be made in connection with all collective bargaining agreements in existence, if any, which affect any worker(s) providing services for the Project; and (f) all contracts with consultants and subcontractors employed, used or engaged by Contractor in connection with the Project have been completed or have been terminated.

ECRC-08-3159 HEARING EXHIBIT - 00000202

The Contractor agrees to defend, indemnify and hold the Released Entities harmless from and against any and all actions, causes of action, losses or damages of whatever kind, including, without limitation, reasonable attorneys' fees and costs in arbitration and at the pre-trial, trial and appellate levels, which the Released Entities may suffer by reason of (a) any claim made against the Project or any of the Released Entities relating to labor, services, materials or equipment furnished by or through the Contractor related to or arising from the Project, or (b) any breach of any representation or warranty made by the Contractor to Owner related to or arising from the Project, including the representations and warranties included herein, any false statement made in this Contractor's Full Lien Waiver and Release or any misrepresentation or omission made to Owner by the Contractor.

The Contractor acknowledges and agrees that (a) Owner is relying upon the representations and warranties made herein as a material inducement for Owner to make payment to the Contractor; (b) this Contractor's Full Lien Waiver and Release is freely and voluntarily given by the Contractor, and the Contractor has had the advice of counsel in connection herewith and is fully informed as to the legal effects of this Contractor's Full Lien Waiver and Release, and the Contractor has voluntarily accepted the terms herein for the consideration recited above; and (c) the tendering of payment by Owner and the receipt of payment and the execution of this Contractor's Full Lien Waiver and Release by the Contractor shall not, in any manner whatsoever, release the Contractor from (i) its continuing obligations with respect to the completion of any work at the Project that remains incomplete, including warranty work or guaranty work, or the correction of defective or non-conforming work; (ii) any contractual, statutory or common law obligations of the Contractor with respect to the Released Entities related to or arising from the Project; or (iii) any other obligations of the Contractor with respect to Released Entities related to or arising from the Project.

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ECRC-08-3160
HEARING EXHIBIT - 00000203

Dated this ___day of _____, 200__.

SUNPOWER CORPORATION, SYSTEMS:

WITNESSES:

_____
Name:_____

_____
Name:_____

By: _____
Name:_____
Title:_____
Address:_____
_____
_____

NOTARIAL ACKNOWLEDGMENT

STATE OF _____)
) **ss:**
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 200__, by _____, the _____ of SunPower Corporation, Systems, a Delaware corporation, who executed the foregoing instrument on behalf of said corporation, and who is personally known to me or who produced _____ as identification.

_____
Name: _____
Notary Public, State of [Florida]
[If notarized in a State other than Florida, Signatory shall comply with the notary requirements of such State.]
Commission No._____
My Commission expires: _____
(Seal)

ECRC-08-3161 HEARING EXHIBIT - 00000204

Appendix R-1 – Form of Subcontractor Certificate for Final Waiver of Liens

HEARING EXHIBIT - 00000205

APPENDIX R-1

FORM OF SUBCONTRACTOR CERTIFICATE FOR FINAL WAIVER OF LIENS

This SUBCONTRACTOR'S FULL LIEN WAIVER AND RELEASE ("Subcontractor's Full Lien Waiver and Release") is made by [_____], a [_____] (the "Releasor"), subcontractor to SunPower Corporation, Systems, a Delaware corporation ("Contractor"), on behalf of Releasor, its successors and assigns, and those acting by or through any of the foregoing, for and in consideration of the sum of Ten and No/100 DOLLARS ($10.00) and other good and valuable consideration, in hand paid, the receipt and sufficiency of which are hereby acknowledged, as full and final payment on account of all labor, services, materials, equipment and other work furnished in connection with the construction of a solar photovoltaic electric generation facility, and all services and utilities related thereto, in De Soto County, Florida (such facility, together with the property on which such facility is located, the "Project") by Contractor on behalf of Florida Power & Light Company, a Florida corporation ("Owner").

Releasor does hereby unconditionally and irrevocably waive, release, remise, relinquish and quit-claim all actions, claims, demands, liens, lien rights and claims of lien, of any kind whatsoever, which Releasor ever had, now has, or may have in the future, known or unknown, against the Project, or against Owner or Contractor, their partners, parents, subsidiaries and affiliates, at all tiers, and their insurers, sureties, employees, officers, directors, representatives, shareholders, agents, and all parties acting for any of them related to or arising from the Project (collectively, the "Released Entities"), including, without limitation, all claims related to, in connection with, or arising out of, all facts, acts, events, circumstances, changes or extra work, constructive or actual delays or accelerations, interferences and the like, which have occurred or may be claimed to have occurred.

The Releasor warrants and represents that (a) the Releasor has not assigned or pledged any rights or claims in any amount due or to become due from Contractor related to or arising from the Project; (b) payment has been or will be made to all of its subcontractors, laborers and material suppliers, at all tiers, for all labor, services, materials and equipment furnished by or through the Releasor for the Project, including all payroll taxes and contributions required to be made; (c) no claims from any of its subcontractors, vendors, mechanics or materialmen against the Released Entities have been submitted to Releasor with respect to the Project or remain unsatisfied as of the date hereof; (d) no mechanics' or materialmen's liens have been filed with respect to the Project that have not been discharged; (e) payment of all amounts due has been made to all consultants, employees, subcontractors, laborers and material suppliers, at all tiers, and all other entities, for all labor, services, materials and equipment furnished by or through Releasor for the Project, including, without limitation, all payroll taxes and contributions required to be made and all wages, overtime pay, premium pay, holiday pay, sick pay, personal leave pay, severance pay, fees, fringe benefits, commissions and reimbursable expenses required to be paid and all deductions for dues, fees or contributions required to be made in connection with all collective bargaining agreements in existence, if any, which affect any worker(s) providing services for the Project; and (f) all contracts with consultants and subcontractors employed, used or engaged by Releasor in connection with the Project have been completed or have been terminated.

The Releasor agrees to defend, indemnify and hold the Released Entities harmless from and against any and all actions, causes of action, losses or damages of whatever kind, including, without limitation, reasonable attorneys' fees and costs in arbitration and at the pre-trial, trial and

ECRC-08-3163 HEARING EXHIBIT - 00000206

appellate levels, which the Released Entities may suffer by reason of (a) any claim made against the Project or any of the Released Entities relating to labor, services, materials or equipment furnished by or through the Releasor related to or arising from the Project, or (b) any breach of any representation or warranty made by the Releasor to the Released Entities related to or arising from the Project, including the representations and warranties included herein, any false statement made in this Subcontractor's Full Lien Waiver and Release, or any misrepresentation or omission made to the Released Entities by the Releasor.

The Releasor acknowledges and agrees that (a) the Contractor and Owner are relying upon the representations and warranties made herein as a material inducement for the Contractor or Owner to make payment to the Releasor; (b) this Subcontractor's Full Lien Waiver and Release is freely and voluntarily given by the Releasor and the Releasor has had the advice of counsel in connection herewith and is fully informed as to the legal effects of this Subcontractor's Full Lien Waiver and Release and the Releasor has voluntarily accepted the terms herein for the consideration recited above; and (c) the tendering of payment by the Contractor and the receipt of payment and the execution of this Subcontractor's Full Lien Waiver and Release by the Releasor shall not, in any manner whatsoever, release the Releasor from (i) its continuing obligations with respect to the completion of any work at the Project that remains incomplete, including warranty work or guaranty work, or the correction of defective or non-conforming work related to or arising from the Project; (ii) any contractual, statutory or common law obligations of the Releasor with respect to any of the Released Entities related to or arising from the Project; or (iii) any other obligations of the Releasor with respect to any of the Released Entities related to or arising from the Project.

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ECRC-08-3164 HEARING EXHIBIT - 00000207

Dated this ___day of _____, 200__.

WITNESSES:

_____
Name:_____

_____
Name:_____

Subcontractor:

By: _____
Name:_____
Title:_____

Address:_____
_____
_____

NOTARIAL ACKNOWLEDGMENT

STATE OF _____)
) **ss:**
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 200__, by _____, the _____ of_____, a _____, who executed the foregoing instrument on behalf of said corporation, and who is personally known to me or who produced _____ as identification.

_____
Name: _____
Notary Public, State of [Florida]
[If notarized in a State other than Florida, Signatory shall comply with the notary requirements of such State.]
Commission No._____
My Commission expires: _____
(Seal)

ECRC-08-3165
HEARING EXHIBIT - 00000208

Appendix S – Form of Request for Change Order

HEARING EXHIBIT - 00000209

APPENDIX S
FORM OF REQUEST FOR CHANGE ORDER
CHANGE ORDER FORM
Florida Power & Light Company
CONTRACT CHANGE ORDER NO. _____

FPL

Contractor: SunPower Corporation, Systems **Title:** **Date:**

CONTRACT CHANGE: (Detail)	Amount (Circle Credits)
This Change Order No. [___], effective [_____], is issued to amend the *Turnkey Engineering, Procurement and Construction Agreement for Solar Photovoltaic Generating Facility Between Florida Power & Light Company and SunPower Corporation, Systems dated June [__], 2008* (the "Agreement") as specified below. The initial capitalized terms used herein, unless otherwise defined in this Change Order, shall have the meanings ascribed to them in the Agreement.	
Contract Start Date: No change **Contract Completion Date:** No change	**Total Authorized Amount This Change Order**

Schedule of Prices: Lump Sum Fixed Price

WORK/SERVICE START DATE: **WORK/SERVICE END DATE:**

It is hereby understood that, if this Change Order is executed by FPL, the Contractor shall implement the above-referenced change(s). If this Change Order is executed by FPL, the changes to the Work, Contract Price, time requirements and/or any other provisions of the Agreement described in this document are considered an amendment to the Agreement. Except as otherwise set forth in this document, the change(s) described in this document do not relieve FPL or the Contractor of their responsibilities described in the Agreement. If this Change Order is executed by FPL, this document constitutes a full and complete settlement with respect to change(s) to the Work, Contract Price, time requirements and/or any other provisions of the Agreement described in this document, including the settlement of compensation to Contractor, for the change(s) described in this document.

_____
Project Manager

COST HISTORY

Original Contract Price	$
Total Previous Changes Auth.	
This Change (Net Amount)	
☐ Firm ☐ Estimate	
Total Contract Price (Including this change)	$
Could this CCO Impact Other Contracts? ☐ Yes ☐ No	

Primary Cause of Change (Check One)

- ☐ Variance from Quantity Estimate
- ☐ Regulatory Requirements
- ☐ Construction Changes
- ☐ Engineering Changes
- ☐ Other Department Requests
- ☐ Vendor Caused (Identify Back Charges)
- ☐ Constructability
- ☐ Other (Specify) _____

SCHEDULE

- ☐ Change Does Not Affect Guaranteed Provisional Acceptance Date
- ☐ Change Wll Affect Guaranteed Provisional Acceptance Date

Accepted by:

_____

Signature: _____
Name (Print) _____
Title (Print) _____
Date: _____

Authorization:
FLORIDA POWER & LIGHT COMPANY

Signature: _____
Name (Print) _____
Title (Print) _____
Date: _____

APPENDIX T

Intentionally Deleted

Appendix U – Form of Letter of Credit

WELLS FARGO BANK, N.A.
TRADE SERVICES DIVISION - STANDBY LETTER OF CREDIT UNIT
One Front Street, 21st Floor, San Francisco, California 94111
Phone: (800) 798-2815 Option 1. E-Mail: sftrade@wellsfargo.com

APPENDIX U

Form of Letter of Credit

Florida Power & Light Company
700 Universe Blvd
Juno Beach, FL
Attention: Project General Manager

Re: Irrevocable Standby Letter of Credit No. _____

Gentlemen:

We hereby establish in your favor this Irrevocable Standby Letter of Credit No. _____ (the "Letter of Credit") for the account of SunPower Corporation, Systems, a Delaware corporation ("Contractor"), effective immediately and expiring on June 30, 2009.

We have been informed by the Applicant, but do not independently verify, that this Letter of Credit is issued pursuant to the terms of that certain Turnkey Engineering, Procurement and Construction Agreement for Solar Photovoltaic Generating Facility dated as of June [__], 2008, between Florida Power & Light Company, a Florida corporation ("Beneficiary"), and Contractor, as the same may be amended (the "Agreement").

1. Stated Amount. The amount of funds available for drawing under this Letter of Credit shall be U.S. $6,900,000.00 (six million nine hundred thousand United States Dollars) (the "Stated Amount").

2. Drawings. A drawing hereunder may be made by you on any Business Day on or prior to the date this Letter of Credit expires by delivering to Wells Fargo Bank, N.A., at any time during its business hours on such Business Day, at One Front Street 21st Floor, San Francisco, CA 94111, a copy of this Letter of Credit together with (i) a Draw Certificate executed by an authorized person substantially in the form of Attachment A hereto (the "Draw Certificate"), appropriately completed and purportedly signed by your authorized officer and (ii) your draft substantially in the form of Attachment B hereto (the "Draft"), appropriately completed and purportedly signed by your authorized officer. Partial drawings and multiple presentations may be made under this Letter of Credit. Draw Certificates and Drafts under this Letter of Credit may be sent by overnight delivery or courier to Wells Fargo Bank, N.A., at its address set forth above Attention: Standby Letter of Credit Unit. Drawings may also be presented to us via telefacsimile to our telefacsimile no. (415) 296-8905 (each such drawing, a "Fax Drawing"); *provided however* that you confirm our receipt of any Fax Drawing by telephone to our telephone no. 1-800-798-2815 (option 1). In the event of a presentation by facsimile transmission, the original of such documents shall be sent to address set forth in the preceding sentence, as aforesaid, by overnight courier for receipt by us within one (1) Business Day of the date of such facsimile transmission.

3. Time and Method for Payment. We hereby agree to honor a drawing hereunder made in compliance with this Letter of Credit by transferring in immediately available funds the amount

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specified in the Draft delivered to us in connection with such drawing to such account at such bank in the United States as you may specify in your Draw Certificate. If the Draw Certificate is presented to us at such address by 10:00 a.m., California time on any Business Day, payment will be made not later than 3:00 p.m., California time on the next day and if such Draw Certificate is so presented to us after 10:00 a.m., California time on any Business Day, payment will be made on the second Business Day. In clarification, we agree to honor the Draw Certificate upon receipt thereof, without regard to the truth or falsity of the assertions made therein.

4. Non-Conforming Demands. If a demand for payment made by you hereunder does not, in any instance, conform to the terms and conditions of this Letter of Credit, we shall give you prompt notice that the demand for payment was not effected in accordance with the terms and conditions of this Letter of Credit, stating the reasons therefore and that we will upon your instructions hold any documents at your disposal or return the same to you. Upon being notified that the demand for payment was not effected in conformity with this Letter of Credit, you may correct any such non-conforming demand.

5. Expiration. This Letter of Credit shall automatically expire at the close of business on June 30, 2009 or such earlier date on which we receive a Cancellation Certificate in the form of Attachment C hereto purportedly executed by your authorized officer upon which this Letter of Credit shall be cancelled (the "Expiration Date").

6. Rollover. The Letter of Credit shall be deemed automatically extended without amendment for one additional period of one (1) year from the present expiration date, unless at least sixty (60) Business Days prior to such expiration date we shall notify you by registered mail or overnight courier at the above address (or such other address as may be designated by you as contemplated by numbered paragraph 9) that we elect not to consider this Letter of Credit extended for such additional one year period; provided, however, in any event this Letter of Credit shall expire on June 30, 2010.

7. Business Day. As used herein, "Business Day" shall mean any day on which commercial banks are not authorized or required to close in the State of California.

8. Governing Law. Except as far as otherwise expressly stated herein, this Letter of Credit is subject to the International Standby Practices ("ISP98"), except for Rule 3:14(a), International Chamber of Commerce Publication No. 590. As to matters not addressed by the ISP98, this Letter of Credit shall be governed by and construed in accordance with the laws of the State of California and applicable U.S. federal law.

9. Notices. All communications to you in respect of this Letter of Credit shall be in writing and shall be delivered to the address shown for you herein before or such other address as may from time to time be designated by you in a written notice to us. All documents to be presented to us hereunder and all other communications to us in respect of this Letter of Credit, which other communications shall be in writing, shall be delivered to the address for us indicated on the signature page hereof, or such other address as may from time to time be designated by us in a written notice to you.

10. Irrevocability. This Letter of Credit is irrevocable.

11. Transferability. We shall not authorize any transfer of this Letter of Credit until a transfer certificate, substantially in the form of Attachment D hereto, is completed to our satisfaction and received by us. All transfer charges shall be for the account of the Contractor. This Letter of

Credit may not be transferred to any person with whom U.S. persons are prohibited from doing business under U.S. Foreign Asset Control Regulations or other applicable U.S. laws and regulations. Transfer of the Letter of Credit may not change the place of expiration from our above office.

12. Complete Agreement. This Letter of Credit sets forth in full our undertaking, and such undertaking shall not in any way be modified, amended, amplified or limited by reference to any document, instrument or agreement referred to herein, except for the ISP-98 and Attachments A, B, C, and D hereto and the notices referred to herein and any such reference shall not be deemed to incorporate herein by reference any document, instrument or agreement except as set forth above.

SINCERELY,

WELL FARGO BANK, N.A.

_____

(Authorized Signature)

ATTACHMENT A

FORM OF DRAW CERTIFICATE

The undersigned hereby certifies to Wells Fargo Bank N.A. (the "Issuer"), with reference to Irrevocable Letter of Credit No. _____ (the "Letter of Credit") issued by Issuer in favor of the undersigned ("Beneficiary") (capitalized terms used herein and not defined herein shall have the respective meanings set forth in the Letter of Credit), as follows:

(1) The undersigned is the _____ of Beneficiary and is duly authorized by Beneficiary to execute and deliver this Certificate on behalf of Beneficiary.

(2) Beneficiary hereby makes demand against the Letter of Credit by Beneficiary's presentation of the draft accompanying this Certificate, for payment of _____ dollars (U.S.$_____), such amount, when aggregated together with any amount not drawn down, is not in excess of the Stated Amount (as in effect of the date hereof).

(3) Beneficiary is entitled to draw the amount set forth in paragraph 2 hereof because:

[Check applicable provision(s)]

[___] The conditions for a drawing pursuant to the Agreement have been met.

[___] The rating of the outstanding unsecured indebtedness of the bank or trust company that issued the Letter of Credit has fallen below a rating of A-, as determined by Standard and Poor's Corporation, or a rating of A-3, as determined by Moody's Investors Services, Inc., and Contractor has failed, within ten (10) days after receipt of written notice (copy attached) thereof by the Beneficiary to replace such Letter of Credit with another Letter of Credit issued by a financial institution acceptable to Beneficiary on the same terms as the Letter of Credit being replaced.

[___] The Contractor has failed to renew the Letter of Credit within sixty (60) Business Days prior to the expiration thereof.

(4) You are hereby directed to make payment of the requested drawing to: (insert wire instructions)

Beneficiary Name and Address

By: _____
Title: _____
Date: _____

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ATTACHMENT B

DRAWING UNDER IRREVOCABLE LETTER OF CREDIT NO. ----------

Date:

ON: If the Draw Certificate is presented by 10:00 a.m., California time on any Business Day, payment will be made not later than 3:00 p.m., California time on the next day and if such Draw Certificate is so presented to us after 10:00 a.m., California time on any Business Day, payment will be made on the second Business Day.

PAY TO: Florida Power & Light Company

$_____U.S.

FOR VALUE RECEIVED AND CHARGE TO THE ACCOUNT OF LETTER OF CREDIT NO. _____.

Florida Power & Light Company

By: _____

Title: _____

Date: _____

ATTACHMENT C

CANCELLATION CERTIFICATE

Irrevocable Letter of Credit No. _____

The undersigned, being authorized by the undersigned ("Beneficiary"), on behalf of Beneficiary hereby certifies to Wells Fargo Bank N.A. ("Issuer"), with reference to Irrevocable Letter of Credit No. _____issued by Issuer to Beneficiary (the "Letter of Credit"; capitalized terms used herein and not defined herein shall have the respective meanings set forth or referenced in the Letter of Credit), that either (i) thirty (30) days have passed since the expiration of the Warranty Period (as defined in the Agreement) and Contractor has satisfied all obligations under the Agreement or (ii) the Agreement has been terminated and Contractor has performed all obligations and paid all amounts remaining due by Contractor following such termination. Pursuant to Section 5 thereof, the Letter of Credit shall expire upon Issuer's receipt of this certificate. Attached hereto is the Letter of Credit marked "Canceled".

Beneficiary Name.

By: _____

Title: _____

Date: _____

ATTACHMENT D
TRANSFER CERTIFICATE

Irrevocable Letter of Credit No. _____

The undersigned Beneficiary hereby certifies to Wells Fargo Bank N.A. ("Issuer"), with reference to Irrevocable Standby Letter of Credit No. _____ (the "Letter of Credit"; capitalized terms used herein and not defined herein shall have the respective meanings set forth in the Letter of Credit), that for value received Beneficiary hereby irrevocably transfers to _____ (the "Transferee") all rights of the undersigned under the Letter of Credit, including all rights of the undersigned to draw under the Letter of Credit and to execute and deliver drafts and draw certificates with respect hereto.

Beneficiary hereby certifies that the Transferee has agreed in writing for Contractor's benefit to be bound by the provisions set forth herein.

By this transfer, all rights of Beneficiary under the Letter of Credit are transferred to Transferee and Transferee shall have sole rights with respect to the Letter of Credit relating to any amendments thereof and any notices thereunder; and all references to "Beneficiary" or "Owner" in the Letter of Credit, any drawing certificate in the form of Attachment A or the other Attachments to the Letter of Credit shall be deemed to mean the Transferee. All amendments are to be advised directly to the Transferee without necessity of any consent of or notice to the undersigned. Simultaneous with delivery of this notice to Issuer, a copy of this notice is being transmitted to Transferee.

The Letter of Credit is returned herewith and Issuer is requested to endorse the transfer on the reverse thereof and forward it with your customary notice of transfer directly to the Transferee at the following address:

Florida Power & Light Company
(or its permitted transferee in interest)

By: _____

Title: _____

Date: _____

SIGNATURE GUARANTEED
The First Beneficiary's signature(s) with title(s) conforms with that on file with us and such is/are authorized for the execution of this instrument.

_____
(Name of Bank)

_____
(Bank Address)

_____
(City, State, Zip Code)

_____
(Telephone Number)

_____
(Authorized Name and Title)

_____
(Authorized Signature)

Appendix V – Contractor's Exclusions

HEARING EXHIBIT - 00000220

APPENDIX V

Contractor's Exclusions

None.

HEARING EXHIBIT - 00000221

APPENDIX W

Intentionally Deleted

APPENDIX X

Intentionally Deleted

Appendix Y –Form of Quality Assurance Programs

HEARING EXHIBIT - 00000224

APPENDIX Y
FORM OF QUALITY ASSURANCE PROGRAMS

Contractor shall have in effect at all times a Quality System which as a minimum conforms to the American National Standard ANSI/ASQ ISO 9001, Model for Quality Assurance, or an approved alternative. The project specific Quality System will conform to but not be identical to the ISO 9001 Model. A site specific Quality System will be submitted for approval. This system shall ensure that all materials and services (including subcontracted materials and services) provided on this project comply with the specification and applicable Codes.

1.0 Quality Assurance Program:

1.1 Contractor shall have a QA Program in effect at all times to verify that all items and services, including subcontracted items and services, comply with the contract requirements.

1.2 This program will clearly establish the authority and responsibility of those responsible for the QA Program. Persons performing quality functions will have sufficient and well-defined responsibility and authority to enforce quality requirements; to identify, initiate, recommend, and provide solutions to quality problems; and to verify the effectiveness of the solutions.

1.3 Contractor shall submit a controlled copy of his QA or Quality Systems Manual for review and acceptance by Owner. In addition, Contractor will make available for review copies of any associated implementing procedures and/or instructions. A post award meeting will be held at Contractor's facility to discuss the Project's QA and quality requirements.

1.4 Contractor shall utilize a quality plan for all stages of the project including design, procurement, installation/erection, testing, start-up and turnover. The quality plan will identify critical activities, inspections and other quality verification points that will be performed to ensure the quality of work meets specified requirements.

1.5 Prior to the post award meeting, Contractor shall make available for review the quality plan for the project that includes implementing procedures, instructions, and check-sheets (which may include but not limited to):

1.5.1 Test & Inspections

1.5.2 Quality System Audits

1.5.3 Nondestructive Examination Control

1.5.4 Control of Special Process

1.5.5 Non-conformance Control and Corrective Actions

1.5.6 Material Control

1.5.7 Document Control and Record Retention

Contractor's preliminary site Construction Quality Plan includes "Inspection and Test plans" that comply with the National Codes (ASME, AWS, ACI). Owner will perform an overview of Contractor's Quality System. This overview does not include "Hold" or "Witness" points. Every effort will be made to implement a meaningful overview without impeding Contractor's efforts or job progress. Owner's overview is intended to assist Contractor implement an effective Quality System and associated quality controls focused on problem prevention and continuous improvement. Concerns arising from the overview activities will immediately be conveyed to Contractor for incorporation into Contractor's Quality System or Project's Quality Plan for corrective action, recurrence control, and trending. Owner's representatives will continually monitor and evaluate Contractor's timeliness and adequacy of corrective actions and recurrence controls.

1.6 If subsequent to its acceptance, the QA Program is found to be ineffective or inadequate in providing acceptable quality controls, Owner reserves the right to require the necessary revisions.

2.0 Contractor's Responsibilities for Suppliers

2.1 Material and equipment quality control: Contractor shall provide new equipment, materials and workmanship for their application.

2.2 Contractor is responsible for the work and materials specified in the contract and shall require its subcontractors/suppliers to comply with the appropriate technical and quality requirements of the specification and associated procurement documents.

2.3 Contractor will identify, in purchase documents to his suppliers, all applicable quality and QA requirements imposed by the specification on Contractor and will ensure compliance thereto. Contractor has the prime responsibility for vendor surveillance and evaluating and monitoring the implementation of

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the Quality Assurance Programs of his suppliers. . The degree of overview should be based on results of the evaluation and ongoing quality performance.

2.4 Contractor will submit a copy of his Vendor Surveillance plans to Owner for review prior to implementation. Upon request, Contractor will submit to Owner copies of the reports of the vendor surveillance activities that he performs on his suppliers.

3.0 Witness Points

3.1 Owner will have the right to establish witness points for which Contractor will give ten (10) business days prior notification. In addition, Owner may establish witness points to ensure resolution of quality problems.

3.2 Witness points are defined as predetermined points during fabrication when equipment or activities may be inspected or witnessed for compliance with the Purchase Order, specification, and quality requirements.

3.3 Owner will have the right to access Contractor and Contractor's Suppliers facilities at any time to verify the progress and quality of the work.

4.0 Stop Work Action

4.1 Owner will orally notify and confirm in writing to Contractor of any situation where, in the judgment of Owner, Contractor or Contractor's suppliers are performing work contrary to the conditions and terms of the Contract or where continued operations could cause damage, preclude further inspection, or render remedial action ineffective for any product or service provided by Contractor or Contractor's suppliers.

4.2 If, after this notification, Contractor does not commence appropriate corrective action to the satisfaction of Owner, Owner will initiate stop work action on the specified product or service and so notify Contractor in writing.

4.3 Upon receipt of a Stop Work Directive (SWD) from Owner, Contractor and Contractor's suppliers will cease operations, including shipments, on any specified product or service to the extent stipulated by the SWD. Resumption of operations will not be undertaken until Contractor has obtained a written authorization from Owner. A written authorization to resume further operations will only be granted upon approval of Contractor's written commitment to correct those conditions itemized on the SWD. Correction of the actual deficiency will be required prior to release for shipment.

5.0 Deviations and Nonconformance's

5.1 Departure from any requirement of this Specification shall be considered a deviation or nonconformance. Examples include physical defects in equipment, test failures, equipment out-of-tolerance, or deviations from the specification, inspection or test procedures. No deviation or nonconformance from this Specification will be accepted until approved in writing by Owner.

5.2 Access to Contractor's facility and their suppliers' facilities shall be provided to the Owner (or agent) at its' option, to evaluate the effectiveness of the quality systems. Necessary changes, which may be required to conform to the above requirements, shall be made by Contractor.

6.0 Inspection, Shop Testing and Quality Verification

6.1 Contractor shall develop, implement and provide to the owner a Quality Control Plan for Equipment Suppliers that identifies the level and extent of shop inspection, testing and other quality verification activities. Contractor shall identify the number of man-days budgeted regarding each equipment supplier listed on the Quality Control Plan.

6.2 Testing programs shall be established by Contractor, but shall not be less thorough than the manufacturer's standard testing procedures or as outlined in the major equipment contracts. Contractor is responsible for insuring that the manufacturers meet specification requirements for quality, inspections and testing contained in all equipment contracts.

6.3 Contractor's inspection and testing programs can be established based on previous experience however Contractor shall demonstrate to Owner justification of inspection activities.

6.4 Contractor shall perform inspection, shop testing or other quality verification activities with appropriately qualified and experienced personnel.

6.5 Contractor shall develop and maintain a monthly schedule that identifies the quality verification activities and witness points to be performed on this project. Copies of this schedule shall be provided to the owner.

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6.5.1 The Owner reserves the right of shop inspection visits and may witness shop tests, provided that Contractors Schedule is not impacted. Any shop inspections by Owner does not relieve Contractor of its responsibility contained in the terms of the Contract. Contractor shall notify Owner of impending inspection visits or tests at least ten (10) business days in advance of inspections or tests. Shop inspections shall also be identified in Contractor's schedule.

6.6 Contractor shall furnish to Owner certified copies of test reports and shop tests whether Owner witnesses the shop test or not.

7.0 Equipment Expediting Services

Expediting services are included for all engineered equipment to track the engineering phase to ensure timely delivery of vendor design drawings and documents, as well as timely engineering design drawing review, and timely resolution of open issues. Expediting services are also included to track the manufacturing and testing phase to ensure timely shipment of equipment that passes all tests and meets vendor as well as Contractor quality assurance and quality control program requirements.

8.0 Construction Quality Control

First line, primary inspection and testing (hereafter referred to as Quality Control) is the responsibility of Contractor. Contractor's quality control procedures shall be clearly stated in the Project's Quality Control Manual, and shall specify field inspections and inspection criteria. Problems discovered during inspections and testing which could impair job cost, schedule, or facility function, will be immediately conveyed to Owner.

9.0 Construction Meetings

Contractor shall conduct meetings with subcontractor supervisory personnel prior to task performance, to insure understanding of the design specification requirements. At this time, inspection requirements and witness points shall be explained. Meetings shall be documented.

10.0 Construction Surveillance

The surveillance, which shall include hands-on inspections and documentation, verifies that the installations conform to the drawings, specifications, and applicable codes. Surveillance shall include in-process inspections, early in the process, as an effort to evoke problem prevention instead of problem resolution that comes with performing only final inspections. Contractor is obligated to engineer, construct and operate equipment in accordance with manufacturers' recommendations. Owner must be notified in writing prior to Contractor initiating actions that deviate from manufacturer's recommendations.

11.0 Test Monitoring

Testing shall be observed and documented by qualified Contractor personnel. Testing procedures and test reports should be reviewed as well as direct observation of the test process.

12.0 Inspection Plan

Contractor shall develop an Inspection Plan that identifies the Quality Control activities Contractor will perform. This plan shall outline the usage and extent of the above methods, or additional methods to be used by Contractor to monitor the quality of the installation. As a minimum, Contractor's Quality Control Program shall include monitor the systems and construction activities identified on Table 1.

13.0 As-Builts

Contractor shall develop and implement a document control program to ensure that the project submittals identified in section 11.3 of the EPC Contract Exhibit A, are properly controlled and as-builts are provided to the owner in accordance to the project document submittal schedule.

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HEARING EXHIBIT - 00000227

Table 1
Minimum Construction QC Program Requirements

Systems/Components to be addressed (include but not limited to):

- Transformers
- Inverters
- Structural Steel
- Protective Relays
- Instruments & Controls
- Foundations
- Motors
- Cable trays, and conduit
- Switchgear, Busway, & Motor Control Centers
- PV panels

Construction Activities to be addressed (include but not limited to):

- Receiving Inspection & Storage
- Soil Compaction
- Coatings Application
- Survey Controls
- Cable Pulling and Terminations
- Host Utility Tie-ins
- Loop Checks of Instruments
- Close-out of Electronic Spaces
- Construction Tests, Turnover and Start Up
- Document Control
- Control of nonconformances
- Concrete Testing
- Structural Steel Jointing
- Setting of Protective Relays
- Close-out of Switchgear and Boxes
- Tagging/Clearance
- Calibration

End

ECRC-08-3185
HEARING EXHIBIT - 00000228

Appendix Z – Form of Safety Plan

APPENDIX Z
FORM OF SAFETY PLAN

Safety Rules and Regulations for Contractors

1.0 Purpose

Safety is vital to the well being of all employees, the quality of the work being done, and the cost effectiveness of Owner projects. The purpose of this procedure is to ensure that contractors comply with OSHA standard 29 CFR Part 1926, identify and correct potential safety hazards prior to starting work, and monitor the effectiveness of their own safety programs.

2.0 Contractor's Responsibilities

2.1 Prior to the commencement of any site work by Contractor, Contractor will designate in writing to Owner a competent safety representative. This representative shall make frequent and regular safety inspections of the jobsite. These inspections shall be documented in writing to Owner's format or similar and submitted to Owner for his review within three (3) working days of performance. All at-risk behavior and/or unsafe conditions noted during the inspections shall be corrected immediately. At risk behavior and /or unsafe conditions noted during inspections shall be corrected immediately. A Job Safety Analysis (JSA) is required to be performed by Contractor for all essential jobs.

2.2 Contractor shall initiate an accident prevention program and shall instruct each employee on the jobsite in the recognition and avoidance of unsafe acts and/or conditions applicable to its work environment to control or eliminate injury. Contractor shall enforce the project and OSHA safety rules on its employees.

2.3 Contractor is responsible for providing and requiring the use of appropriate personal protective equipment (PPE) in all operations where there is and exposure to hazardous conditions or where the hazard assessment results would require PPE.

2.4 Contractor shall designate in writing to Owner the names of the competent persons as required by OSHA Standard 29 CFR Part 1926 for Contractor's work activities. Contractor shall ensure this individual understands his responsibilities and is capable of identifying existing and predictable hazards in the surroundings or working conditions which are unsanitary, hazardous, or dangerous to employees, and understands that he/she has the authorization to take prompt corrective measures to eliminate them.

2.5 Contractor shall initiate and implement a hurricane/severe storm preparedness procedure in accordance with section 23.0. (Need Clarification. OSHA Section 1926.23 does not refer to hurricane/severe storm preparedness.)

3.0 Pre-Construction Meeting

Contractor shall attend a pre-construction meeting with Owner to understand the project conditions, safety requirements, and site policies and rules before starting work at the jobsite. A jobsite tour may be made to confirm Contractor's awareness of potential safety hazards. It is Contractor's obligation to implement measures necessary to establish and maintain safe working conditions on the Project.

4.0 Instruction and Training

Instruction and training of employees in an OSHA requirement will be required on this project. Examples of such training to be provided by Contractor are:

4.1 Orientation -- Newly employed or transferred personnel shall be instructed in the site safety rules/policies and the safety practices required by their work assignments. Contractor shall document this training and demonstrate to Owner that the employees know and understand the training.

4.2 Daily Work Assignments – All work assignments must include specific attention to safety. The Risk Assessment Tailboard (RAT) process or equivalent will be utilized each morning or when a new task is assigned. (See attached program)

4.3 Safety Meetings – Properly conducted and recorded weekly safety meetings are required. Results of these safety meetings are to be submitted to Owner within three (3) working days for review.

4.4 Specific Instructions – OSHA requires that employees who perform specific tasks or operate specific equipment be trained in its usage. Contractor shall ensure only those personnel qualified by training or experience shall be permitted to operate machinery. These qualifications shall be documented by Contractor, maintained and kept on file at the jobsite for review by Owner.

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5.0 Recordkeeping

It is the Contractor's responsibility to maintain all records required by OSHA, Workers Compensation Insurance or similar regulations. This includes the maintenance of an accident log, annual summary and posting of posters.

6.0 Hazardous materials

6.1 Contractor is responsible for notifying Owner of any hazardous chemicals or substances that are brought or caused to have been brought on the jobsite. The legal storage, use, and disposal of hazardous chemicals or substances are the responsibility of Contractor.

6.2 If hazardous chemicals are going to be used, then Contractor will implement a Hazard Communication program that will include training, MSDS, and labeling.

6.3 Use of chemicals may result in hazardous waste. In such cases, the Contractor shall institute a program to address hazardous waste storage and disposal in accordance with the code of federal regulations, state regulations, and other requirements delineated in the bid and contract documents.

6.4 When personal exposure to chemicals, particulates, aerosols or fumes is reasonably expected to exist and exceed allowable limits, then the Contractor shall put an Industrial Hygiene program in place.

7.0 Fire Prevention

7.1 Contractor shall be responsible for fire protection in its work, operational, and storage areas in accordance with all local, county, state, and federal requirements 24 hours per day, seven days per week, through the duration of this contract

7.2 Contractor shall comply with all fire and safety rules and regulations established on the project

8.0 Third Party Safety Inspections

In addition to visits and safety inspections by corporate representatives, Contractor is advised that the Project may be inspected from time to time by authorized third parties. These may include representatives of Owner, insurance companies, or OSHA. Upon proper identification, they are entitled to access and courteous consideration.

9.0 Project Safety Rules and Guidelines

All personnel on the project are required to comply with project specific rules and these guidelines. Contractor shall ensure that all of its employees have read these guidelines and understand its contents. The following jobsite rules apply:

9.1 Clothing Requirements

9.1.1 Shirts with at least a 4-inch sleeve shall be worn at all times. Tank tops are not permitted.

9.1.2 Long pants are required.

9.1.3 Sandals, tennis shoes, or any other street type shoe will not be permitted.

9.1.4 Loose fitting clothes or jewelry shall not be worn around moving machinery, grinding operations, etc.

9.2 Personal Protective Equipment

9.2.1 ANSI approved hard hats shall be worn at all times in the construction area unless a hazard assessment performed by the Contractor shows that wearing the hard hat would make the specific job more unsafe. All areas of this jobsite are hard hat areas. This includes cabs on heavy equipment such as cranes and backhoes.

9.2.2 Safety glasses with side shields are required in the construction areas at all times.

9.2.3 Approved eye and face protection is required as follows: goggles, welding hoods and shields, and face shields will be required to be properly worn at all times when in the area of operations, such as when welding, burning, grinding, chipping, chemical handling, corrosive liquids or molten materials, drilling, sawing, driving nails, power actuated tools, concrete pouring, tampers and gas fueled hand operated equipment (i.e. chainsaws). This section will also apply to those employees of Contractor who are assisting any worker as an apprentice or helper. Prescription glasses must be ANSI approved or safety glasses must be worn over the prescription glasses.

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9.2.4 OSHA approved hearing and respiratory equipment shall be worn when required. Contractor shall meet the selection, fitting and maintenance requirements of OSHA.

9.2.5 All employees shall wear approved safety harnesses when working six feet or more above the ground or when working in a precarious position. The lanyard shall be securely attached to the employee 100% of the time and shall be rigged such that the employee can neither free fall more that 6 feet (1.8m), nor contact any lower level. Safety harnesses shall also be worn and attached to the tie-off rail when working out of extensible and articulating boom platforms and to vertical drop lines when working from suspended scaffolding. Specific project requirements may exist and contractor will adhere to the more stringent requirements of fall arrest equipment use.

9.2.6 Seat belts shall be worn by all employees operating any motor vehicle and any equipment with rollover protection structures during performance of the work.

9.2.7 Safety nets shall be provided when work places are more than 25 feet above the ground where the use of other fall protection devices is impractical.

9.2.8 Approved work boots or shoes shall be worn in all construction areas unless a hazard assessment performed by the Contractor shows that ANSI approved shoes are required. All contractors shall ensure that their work boots or shoes provide adequate protection from foot injuries due to falling or rolling objects as identified in the hazard assessment. Deck and athletic style shoes are not considered an approved work shoe and are not to be worn on the project.

9.2.9 Chemical resistant protective footwear shall be worn when there is a possibility of hazardous chemicals coming in contact with the foot. Chemical resistant footwear shall be resistant to the type of chemical to which it is exposed.

9.2.10 Work gloves are required to be worn for all manual material handling jobs.

10.0 Signs, Signals, Barricades and Lights

10.1 Signs, Signals and barricades shall be visible at all times where a hazard exists.

10.2 All streets, roads, highways, and other public thoroughfares, which are closed to traffic, shall be protected by effective barricades on which shall be placed acceptable and highly visible warning signs. Barricades shall be located at the nearest intersecting public highway or street on each side of the blocked section.

10.3 All open trenches and other excavations shall be provided with suitable barriers, signs, and lights to the extent that adequate protection is provided. Obstructions, such as material piles and equipment, shall be provided with similar warning signs and lights.

10.4 All barricades, signs, lights and other protective devices shall be installed and maintained in conformity with applicable statutory requirements.

10.5 When any work is performed at night or where daylight is shut off or obscured, Contractor shall, at its expense, provide artificial light sufficient to permit work to be carried on efficiently, satisfactorily and safely, and to permit thorough inspection. During such times, the access to the place of work shall also be clearly illuminated. All wiring for electric light and power shall be installed and maintained in a first-class manner, securely fastened in place at all points, and shall be kept as far as possible from telephone wires, signal wires, and wires used for firing blasts.

10.6 Signs, signals and barricades shall be removed when the hazard no longer exists.

10.7 Contractor's employees working in an area of potential traffic had shall wear approved reflective type vests.

11.0 Rigging Equipment

11.1 All rigging equipment shall be free from defects, in good operating condition and maintained in a safe condition. Rigging equipment shall be inspected before use on each shift and as necessary to ensure that it is safe.

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11.2 A designated, competent employee of Contractor shall thoroughly inspect rigging equipment monthly to ensure that it is safe. Records shall be kept on jobsite of each of these inspections by Contractor and shall be made available to Owner upon request.

11.3 Contractor shall immediately remove damaged rigging equipment from service.

12.0 Hand and Power Tools

12.1 All hand and power tools, whether furnished by Contractor, or by Contractor's employee, shall be maintained in a safe condition.

12.2 Contractors shall not issue nor permit the use of unsafe hand or power tools.

12.3 Electrical power tools shall be grounded or double insulated with proper assured equipment grounding inspections or Ground Fault Interrupter circuit protection provided.

12.4 Pneumatic power tools shall be secured to the hose or whip by some positive means.

12.5 Only properly trained Contractor's employees shall operate power actuated tools. Contractor shall maintain certification records, employee certification cards, or equivalent certification documentation or each of its employees using power actuated tools during performance of the work.

12.6 All portable grinders shall conform to OSHA and ANSI requirements.

12.7 Cords, leads and hoses shall be kept at least seven feet off the ground or placed off to the side to prevent creating a tripping or traffic hazard.

13.0 Compressed Gas Cylinders

13.1 Compressed gas cylinders shall be secured in an upright position at all times. Location of cylinder storage areas must be approved by Owner.

13.2 When transporting, moving and storing cylinders, valve protection caps shall be in place and secured.

13.3 Cylinders shall not be hoisted by magnets or choker slings. Valve protection caps shall not be used for hoisting cylinders.

13.4 Cylinders shall be kept away from sparks, hot slag and flames, or be adequately protected.

13.5 Cylinders shall not be placed where they can become part of an electrical circuit.

13.6 Cylinders shall be labeled as to the nature of their contents.

13.7 Oxygen cylinders in storage shall be separated from fuel gas cylinders or combustible material a minimum of 20 feet, or by a non-combustible barrier at least five feet high having a fire resistant rating of at least one-half hour. Empty cylinders shall be separated as above from full cylinders and stored with like cylinders.

13.8 "No Smoking" signs shall be posted at storage areas and signs shall clearly indicate contents of cylinders.

13.9 Anti-flash back valves shall be provided on all oxygen and acetylene lines.

14.0 Jobsite Transportation Rules

14.1 All drivers of motor vehicles shall be licensed, trained, and instructed to exercise good cautious operating judgement as well as observe posted speed limits. Maximum speed limit is 25 miles per hour unless posted otherwise. However, slower speeds are necessary in congested areas.

14.2 Seat belts shall be worn at all times when travelling in vehicles and equipment.

14.3 All Contractor's means of ingress, egress and parking will be adequately marked as such, since their employees are to travel these routes only.

14.4 Use your horn for safety at blind corners, when passing, etc.

14.5 Established hand signals or turns signals are to be used.

14.6 Reckless driving or other non-observance of these instructions will be cause for withdrawal of drive-in privileges and may result in denial of access to the project.

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15.0 Cranes and Derricks

15.1 Contractor shall certify all cranes and derricks as being in safe operating condition before using the crane or derrick on jobsite. This certification shall be maintained by Contractor and made available to Owner upon request.

15.2 Contractor shall comply with the manufacturer's specifications and limitations applicable to the operation of all cranes and derricks. Contractor shall designate a competent person who shall inspect all machinery and equipment before each use, to make sure it is in safety operating condition. Any deficiencies shall be repaired, or defective parts replaced, before continued use.

15.3 The swing radius of cranes shall be barricaded where practical and/or in areas where work is being performed.

15.4 Hand signals prescribed by ANSI shall be posted at an operator's station; employees assigned to work around the crane will be trained in the use of hand signals.

15.5 Equipment shall not be operated where any of the equipment or load will come within 10 feet (3.1 M) of electrical distribution or transmission lines less than 50 kV. Minimum clearance between lines and any part of the crane or load must be 10 feet plus 0.4 inches for each 1 kV over 50 kV or twice the length of the line insulator but never less than 10 feet.

15.6 Contractor's employees shall not ride headache ball, hook, or load being handled by the crane.

15.7 While in use, equipment shall not be lubricated or have maintenance performed.

15.8 Rated load capabilities, recommended operating speeds, special hazard warning, specific hand signal diagrams and special instructions shall be visible to the operator while he is at the control station.

15.9 Contractor's employees shall not be allowed to work under the load of cranes. Tag lines shall be used on all loads. Special caution should be used in concrete bucket operations.

15.10 Cranes and derricks shall be inspected prior to use and at monthly intervals. Contractor shall maintain records on jobsite of these inspections. Contractor shall make copies available to Owner upon request.

16.0 Equipment and Motor Vehicles

16.1 All equipment must be inspected daily before use by Contractor's operator. Contractor must also make formal inspections at 30-day intervals with proper documentation maintained at the jobsite by Contractor and copies shall be made available to Owner upon request.

16.2 Defective equipment shall be repaired or removed from service immediately.

16.3 All rubber-tired, self-propelled scrapers, rubber-tired, front-end loaders, rubber-tired dozers, wheel-type agricultural and industrial tractors, crawler tractors, crawler-type loaders and motor graders shall be equipped with rollover protective structures and seat harnesses.

16.4 All Contractors' operators of construction equipment should be properly licensed and certified by a competent person. Copies of the certifications shall be maintained on jobsite by Contractor and made available to Owner upon request.

16.5 All equipment with an obstructed view to the rear must have a reverse signal alarm audible above the noise level or a flagman.

16.6 All cracked or broken glass shall be replaced before bringing vehicles on the jobsite. If glass is broken or damaged on jobsite and if damage is severe enough to cause a potential safety problem, the machine shall be stopped until such damage has been repaired.

16.7 Vehicles used to transport employees shall have seats firmly secured and adequate for the number of employees to be carried and all passengers should be properly seated. Standing on the back of moving vehicles is prohibited.

16.8 Location for storage of all fuels, lubricants, starting fluids, etc., shall be reviewed by Owner before use by Contractor.

17.0 Ladders

17.1 The use of ladders with broken or missing rungs or steps, broken or split rails or other defective construction is prohibited.

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17.2 Ladders shall extend no less than thirty-six inches (36") above landing and be secured to prevent displacement.

17.3 Portable ladders must be equipped with safety shoes.

17.4 Wooden ladders shall not be painted.

17.5 Metal or conductive ladders shall not be used on the jobsite.

18.0 Floor and Wall Openings and Stairways

18.1 Floor and wall openings shall be guarded by a standard guardrail, midrail, and toeboard, or a cover installed and secured to prevent movement.

18.2 Guardrails must be of sufficient strength to support two hundred (200) pounds of pressure when applied at midspan of the guardrail parallel with the floor and perpendicular to the guardrail with a minimum deflection of three (3) inches.

18.3 Covers must be adequately secured to prevent displacement and have "Danger" signs attached identifying the hazard.

18.4 Every flight of stairs having four or more risers shall be equipped with standard stair railings. Stairs are not to be used until risers and railings are securely installed. Treads will be poured as soon as possible were poured treads apply.

18.5 Debris and other loose materials shall not be allowed on stairways or at access point to stairway. Debris shall not be allowed to accumulate on stairwells.

19.0 Excavations and Trenching

19.1 Prior to opening any excavation or trench, Contractor must notify Owner. In addition, Contractor shall contact any other necessary personnel to determine whether underground installations, i.e., sewer, telephone, fuel, electric lines, etc., may be encountered and where they are located. An excavation permit may be required specific by project.

19.2 Excavations and trenches shall be inspected by a competent person daily and after every rainfall to determine if they are safe.

19.3 After the soil is classified, all banks 4 feet high or more shall be sloped to the angle of repose (the greatest angle above the horizontal place at which a material will lie without sliding), shored, or have trench shields installed.

19.4 Ladders or steps shall be provided in all trenches 4 feet or more in depth. Ladders or steps shall be located to require no more than 25 feet of lateral travel before having access or egress.

19.5 Material excavated shall be stored at least 2 feet from the edge of the excavation, or the trench shall be shored to prevent material from falling into the excavation.

19.6 All trenches and excavations shall be properly barricaded to prevent persons from waling into them.

19.7 All walkways or ramps crossing over excavations shall be securely fastened and equipped with standard guardrails.

20.0 Housekeeping

20.1 During the course of construction, all debris and scrap material shall be kept away from the work area.

20.2 Containers shall be provided by Contractor for the collection and separation of waste, trash, oily and used rags and other refuse. Metal (dumpster type) containers must be used and emptied promptly.

20.3 Garbage and other waste shall be disposed of at frequent and regular intervals in a manner approved by Owner.

20.4 Contractor shall notify Owner of any hazardous waste it will generate during performance of the work. Contractor has the direct responsibility of maintaining proper storage of these wastes while onsite and will verify to Owner in writing that the wastes have been disposed of in a legal manner.

20.5 Contractor shall not pour, bury, burn, nor in any way dispose of any chemical on the work jobsite without the written permission of Owner.

20.6 Contractor shall dispose of all combustible debris to a solid waste disposal site.

ECRC-08-3192 HEARING EXHIBIT - 00000235

20.7 NO OPEN BURNING OF DEBRIS OR RUBBISH WILL BE PERMITTED ON THE PROJECT.

20.8 Materials and supplies shall be stored in locations that will not block access ways, and shall be arranged to permit easy cleaning of the area.

20.9 All hoses, cables, extension cords, and similar materials shall be located, arranged, and grouped so they will not block any access way and will permit easy cleaning and maintenance.

21.0 Medical Services - Contractor's Responsibilities:

21.1 Provisions shall be made prior to commencement of the project for prompt medical attention in case of serious injury.

21.2 Contractor shall ensure that first aid supplies be easily accessible when required. Contents shall be inspected and refilled weekly.

21.3 Contractor shall provide proper equipment for prompt transportation of injured person to a physician or hospital or a communication system to contact necessary ambulance service.

21.4 Contractor shall post telephone numbers and addresses of the physicians, hospital and ambulances.

21.5 Contractor shall complete and retain on file "Employer's First Report of Injury" and OSHA Form 300 and provide Owner a copy upon request.

21.6 Contractor shall ensure that each of its lower-tier subcontractors meet these medical requirements.

22.0 First Aid and Medical Procedures

22.1 Each occupational illness or injury shall be reported immediately by Contractor to Owner's project manager. For emergency cases, ambulance services will be contacted immediately by the quickest means available.

22.2 A daily record shall be kept on all employees requiring first aid treatment.

22.3 If medical treatment is required, Contractor must provide transportation of the injured to a hospital or physician. A representative of the Contractor shall accompany the injured employee and remain at the facility until the employee is ready to return. All reports from the physician concerning treatment, diagnosis, return to work status and restrictions shall be brought back to the project and a copy forwarded to Owner's construction manager, subject to employee's permission through the medical treatment authorization form provided in contractors safety plan..

22.4 Contractor must conduct accident investigations for all serious accidents and OSHA recordable injuries. The accident report shall include root cause determination, corrective actions taken, and measures to prevent the incident from reoccurring.

23.0 Hurricane/Severe Storm Emergency Response Procedure

23.1 Contractor will implement an organized, orderly system to prepare the Project site for inclement weather associated with hurricanes or severe storms.

23.2 Contractor is responsible for training each of their employees on the Construction Project Hurricane / Severe Storm Emergency Response Procedure

23.3 Contractor shall establish a Storm Damage Assessment Team.

23.4 Contractor shall monitor hurricane / severe storm activity by all available resources (i.e. Internet, radio broadcast, weather bulletins, etc).

24.0 Hurricane / Severe Storm Preparedness Plan:

Contractor program shall address inspection of work areas; storage areas, shops and trailers to ensure all equipment and material are properly secured. As a minimum, the following activities shall be addressed:

24.1 Hurricane / Severe Storm Watch (36 to 48 Hours Notice):

24.1.1 Band and secure all lumber.

24.1.2 Band and secure all plastic pipe, conduit, and other similar objects.

24.1.3 Band and secure all siding, decking, sheet metal, and other similar objects.

24.1.4 Dismantle and/or secure all scaffolds and temporary platforms.

ECRC-08-3193 HEARING EXHIBIT - 00000236

24.1.5 Inspect and secure all temporarily installed piping, ductwork, and equipment. The may include adding lashing or lowering the equipment or material to the ground.

24.1.6 Finish bolting up all unfinished erected structural steel. Add additional steel, if necessary, to ensure the stability of the structure.

24.1.7 Lash down all unsecured tanks, silos, ductwork, and hoppers.

24.1.8 Tie down all storage vans, SEA containers, and temporary structures. This includes stairways, printshacks, and other similar structures.

24.1.9 Tie down all gang boxes or other similar items located in elevated positions up in the structures.

24.1.10 Dismantle and/or secure all large signs and similar structures.

24.1.11 Remove all radiation sources from the project.

24.1.12 If possible, remove all fuel trucks and tanks from the project. Trucks and tanks left onsite shall be secured and diked to contain a spill.

24.1.13 If possible, all hazardous material shall be removed from the project. Material left onsite shall be secured and diked to contain a spill.

24.1.14 All elevated work areas for example; Turbine decks shall be cleared of all loose material.

24.2 Hurricane / Severe Storm Warning (1 to 24 Hours Notice):

24.2.1 Contractors should make sure that all materials and equipment are secured by this time.

24.2.2 Shut down the Project Construction Power System.

24.2.3 Shut off the construction water system.

24.2.4 All crane booms shall be lowered to the ground and secured.

24.2.5 All small vehicles such as golf carts, welding machines and compressors shall be secured.

24.2.6 All office trailers and buildings shall be locked.

24.2.7 Project shall be evacuated.

24.3 Following a Hurricane / Severe Storm:

24.3.1 Once the hurricane / severe storm has passed, the Storm Damage Assessment Team shall return to the site to determine if the site is safe for employee re-entry.

24.3.2 Each contractor shall appoint a management person as a contact. The Storm Damage Assessment Team shall communicate to the appointed persons the condition of the site.

24.3.3 If the site is unsafe for employee entry, the Storm Damage Assessment Team shall determine what resources are needed to make the site safe for re-occupancy.

24.3.4 The Storm Damage Assessment Team shall request from the appropriate contractor site management appointee the necessary resources to prepare the site for re-occupancy.

24.3.5 Only when the site has been determined safe for re-occupancy by the Storm Damage Assessment Team, shall site personnel be allowed back to the site to resume normal construction activities.

24.4 Hurricane/Severe Storm Response Construction Site Team

Contractor shall maintain a list of team members and phone numbers of those employees on the site teams.

ECRC-08-3194 HEARING EXHIBIT - 00000237

EXHIBIT Z
FORM OF SAFETY PLAN
(continued)

EXHIBIT Z - ATTACHMENT 1

My Safety Principles

- Plan every job
- Anticipate unplanned events
- Use the right tool for the job
- Identify the hazard
- Assess the risk
- Put controls in place to minimize the possibility of injury
- Protect each other
- Use a "Buddy" system
- Do not take short cuts
- Believe in Zero injuries
- Wear protective equipment
- Keep all work areas clean
- Inspect all tools prior to each use

Post Job Safety Review

1. Was anyone injured or did an unplanned event occur today?
   Yes_____ No_____
   If yes, explain:
   _____
   _____
   _____
2. What problems did you have with today's work assignment?
   _____
   _____
   _____
3. What can we do tomorrow to improve performance?
   _____
   _____
   _____
4. Other concerns/comments
   _____
   _____
   _____

Reviewed by: _____
Supervisor/foreman

_____
Crew

Name	Badge #

FPL Energy

Power Generation Projects

Risk Assessment/Tailboard Sheet

Safety Pod Team

SOARING TO NEW HEIGHTS

FPL

Tailboard

Supervisor_____
Date_____
Job description_____
_____
Location _____
Is a specific procedure required for this job? Yes ____ No ____
If yes, review procedure.
Is specific training required for this job?
Yes ____ No ____
If yes, ensure training is done.

Personal Protective Equipment

	Yes	No	Type *
Eye/face	____	____	_____
Fall	____	____	_____
Hand	____	____	_____
Hearing	____	____	_____
Respirator	____	____	_____

* Type PPE: faceshield, goggles, ear plugs/muffs, welding(leathers), life vest, safety harness, special gloves (chemical resistant), respirator.

Other_____
_____

Material Safety Data Sheet

____ I have a copy of and have read the Material Safety Data Sheet for the hazardous chemical that I am using.

Risk Assessment

Potential Hazards	*Controls or Corrective Measures*

Housekeeping
____Keep work area and access clear
____Remove nails in boards
____Clean work area daily

Fall Protection
____100% tie off above 6 feet
____Lifeline installed
____Double Lanyards/harness

Lifting
____Lift with legs and with back straight
____Get help with heavy loads
____Use material handling equipment
____Get help for weight over 40 lbs

Ladders
____Tie off ladders using 4 to 1 rule
____Face ladder when climbing
____Use both hands when climbing
____Extend 36" above landing
____Use handline to raise or lower tools
____One worker on a ladder

Pinch Point/Line of Fire
____Wear gloves
____Be aware of swing radius on machinery
____Don't place hands on end of pipe
____Use a tag line to control material

Lockout Tagout
____The equipment has been properly tagged or locked out, drained, vented, and energy released

Rigging
____Inspect rigging before each use
____Do not work under and overhead load
____Check load charts for safe work limits
____Check tag on nylon sling for load limits

Power Hand Tools
____Use guards and handles
____Wear eye protection
____Unplug tools when not in use
____Proper tool is in use for the job
____Inspect tools daily

Welding/Burning
____Wear gloves/protective clothing
____Use cutting/burning goggles
____Use/inspect fire extinguisher
____100% spark containment
____Ground welding machine
____Post "Hot Work Permit" if required
____Move/cover combustibles in area

Excavations
____Ladders every 25 feet
____Know soil classification
____Slope, shore, or shield over 5 feet
____Barricade around open trench
____Keep spoils 2 ft back from edge

Scaffolds
____Check for ladder access
____Insure standard guardrails are installed

EXHIBIT Z - ATTACHMENT 2
Risk Assessment Tailboard (RAT) Process

Definition

The Risk Assessment Tailboard sheet is a daily task process that empowers the employees to assess the hazards for the job and implement controls necessary to attain Zero accidents. It also provides a check sheet for personal protective equipment use, training, procedural compliance, and provisions for a post safety job review. The risk assessment process is to be used at least daily.

Purpose

FPL recognizes the importance of holding tailboards before each job, assessing the hazards of that particular job, and instituting the necessary controls to minimize the potential for injury. Daily planning involves safety instruction by the supervisor and crew input into the hazard assessment and control process before the job begins.

Process

- All known hazards must be identified, removed, abated, and/or acknowledged by the crew.
- The foreman/supervisor shall analyze each task for hazards and indicate what safety measures need to be taken.
- The supervisor shall ensure that each employee understands the work to be performed, hazards present, and corrective measures needed to prevent injury.
- If the work changes or unexpected problems arise during the work activities, then another safety assessment is to be done.
- The supervisor shall assure that the necessary safety equipment, procedures, and/or training is provided to the employees before work begins.

Documentation and Feedback

With the exception of the post job safety review, the RAT sheet is to be completed entirely before the work begins. It is the supervisor's responsibility to audit the work throughout the day to ensure adherence to the risk assessment process.

FPL construction management has the responsibility to audit the work activities throughout the day to ensure precautions are being taken and controls are in place.

At the end of the day, the supervisor completes the post job safety review section of the RAT sheet. It is then turned in to the FPL Construction Manager weekly for review and action as needed.

Report all accidents and near misses to supervision. It is essential to analyze these incidents to determine why problems occurred and to institute changes for future work.

END

ECRC-08-3196
HEARING EXHIBIT - 00000239

Appendix Z-1 – Safe and Secure Workplace Policy

HEARING EXHIBIT - 00000240

APPENDIX Z-1
SAFE AND SECURE WORKPLACE POLICY

Rev. 9/9/98

SAFE AND SECURE WORKPLACE POLICY FOR SUPPLIERS

Objective: To provide a safe and secure workplace for FPL employees, supplier employees, customers and the public.

Scope: This Policy applies to any individual or organization, its employees and its sub-contractors, (hereinafter collectively referred to as "Supplier"), responsible for performing the work identified by the purchase contract, for or on behalf of Florida Power & Light Company (hereinafter referred to as "FPL") and its subsidiaries on FPL premises, FPL customers' premises, FPL rights-of-way or FPL facilities, including facilities under construction and excluding only nuclear power stations, (hereinafter collectively referred to as "FPL Premises"), for periods equal to or greater than 30 employee days cumulative per calendar year. For example, if a Supplier has 30 employees who each work one full 8 hour day on FPL Premises in any one calendar year, this Policy applies to the Supplier. If a Supplier has one employee who works 30 or more full 8 hour days in any one calendar year on FPL Premises, this Policy applies to the Supplier.

The policy covers three specific areas:

- Pre-assigned Screening
- Controlled Substance and Alcohol Abuse
- Workplace Violence Policies

Violation: If Suppliers' employees are found to be in pre-access violation of this Policy, Supplier's employees shall be denied access to FPL Premises. Supplier employees found to be in post-access violation of any part of this Policy shall be removed immediately by the Supplier from FPL's Premises.

Compliance: If Supplier fails to comply with this Policy, Supplier may be considered in breach of contract. FPL or its designee shall have upon request immediate access to Suppliers' records to assure compliance with the requirements of this Policy.

Policy Details: The Supplier must address three specific issues regarding Safe and Secure Workplace.

II. Controlled Substances and Alcohol Abuse:

All Supplier employees should be fit-for-duty and report to work able to perform their duties safely. Use or possession of controlled substances and/or alcoholic beverages, as defined in

Chapter 561 of the Florida Statutes, by Supplier employees is an unsafe work practice which creates an increased risk to Supplier employee safety and the safety of others. The use or possession of any illegal drug or controlled substance without a valid prescription and/or the misuse of any prescription or over-the-counter medication by any Supplier employee shall constitute a violation of this Policy.

Any Supplier employee who is consuming or is under the influence of any alcoholic beverage while on FPL Premises shall be in violation of this Policy.

All Suppliers must have in place a controlled substance and alcohol Policy All employees who are subject to the requirements of the Omnibus Transportation Employee Testing Act of 1991, including Supplier employees required to hold a Commercial Driver's License, will be subject to random testing for controlled substances and alcohol according to the federally mandated random testing rate.

Supplier employees will be denied access to or immediately removed from FPL Premises for: (1) Possession or use of a controlled substance without a valid prescription; (2) distribution or sale of controlled substances at any time on or off the job; (3) positive test result for controlled substances without a valid prescription or alcohol; (4) being under the influence of a controlled substance or alcohol; or (5) refusal to test for controlled substances or alcohol.

ECRC-08-3198
HEARING EXHIBIT - 00000241

Supplier employees taking prescription medication are required to consult with their physicians to determine whether the medication may have an adverse effect on performance. Supplier employees taking over-the-counter medication are responsible for being aware of any adverse effects it may have on their performance as defined on the manufacturer's label. If prescribed or over-the-counter medication may have an adverse effect on performance, the Supplier employee is required to notify the Supplier prior to reporting to FPL's Premises. Failure to inform the Supplier's representative of taking prescription or over-the-counter medication which may have an adverse effect on performance may result in that employee's denial of access to FPL Premises. In all events the Supplier is responsible for determining the employee's fitness for duty.

Supplier employees taking prescription medications must be prepared to provide satisfactory, verifiable proof that the medication has been prescribed to the Supplier employee, and that it is necessary for the individual's current medical condition. Possession of the prescription bottle will provide the required proof.

Any Supplier employee called to perform unscheduled work at FPL Premises must state whether he/she has consumed alcohol within five (5) hours of the time he/she reports to work or is otherwise "unfit" for duty. Supplier employees that have consumed alcohol within the five (5) hour abstinence period shall not be permitted to work on FPL Premises except under conditions when:

1. The Supplier employee being called believes that he/she is fit for duty; and, based on information provided by the individual, the Supplier also believes he/she is fit for duty; or
2. The Supplier employee's fitness for duty is verified by a breath analysis for alcohol prior to entering the FPL worksite and the individual believes he/she is fit for duty.

In addition to the requirements set forth herein, all Suppliers shall comply with all applicable state and/or federal laws regarding drug and alcohol testing of their employees that are assigned to FPL Premises. All testing performed pursuant to this policy shall be at the blood alcohol rates specified in the Omnibus Transportation Employee Testing Act of 1991. **All Supplier employees will be subject to "post accident" and/or "reasonable suspicion" controlled substances and alcohol testing while on FPL Premises. "Reasonable suspicion" shall be determined in the sole discretion of FPL. No Supplier employee required to take a post-accident alcohol test under the Policy shall use alcohol for eight hours following the accident, or until he/she undergoes a post-accident alcohol test, whichever occurs first. This testing will be required when there is reasonable suspicion that an individual is in violation of the substance abuse and alcohol Policy. Supplier shall immediately notify FPL of any accidents involving or caused by its employees or subcontractors on FPL Premises.**

III. Workplace Violence:

FPL is committed to providing a safe and secure workplace. Supplier employees are expected to work in concert with FPL employees to ensure that the workplace remains safe and secure for all.

Behavior that could be perceived by a reasonable person as threatening or indicating the possibility of violence is prohibited. This may include, but is not limited to verbal threats, gestures, abusive language or physical altercation (fighting, shoving, etc.).

Displaying or carrying in any manner a weapon, firearm or destructive device (as those terms are defined in Chapter 790 of the Florida Statutes) on the Supplier employee's person or in his/her belongings, on any FPL Premises, in his/her personal vehicle while engaged in FPL work or activities, or in an FPL vehicle at any time is prohibited.

Supplier employees that violate these policies will be removed immediately by the Supplier from FPL Premises, and denied access to any FPL Premises. Supplier shall immediately notify FPL Corporate Security of violations of this Section III.

IV. Reporting Illegal Conduct or Workplace Violence:

FPL employees and Supplier employees benefit from an atmosphere of good ethical and legal conduct. Suppliers and their employees with information concerning abuse of company assets, fraud, theft, possession or use of illegal drugs, threats of violence or any other behavior at FPL that might be considered illegal, shall

ECRC-08-3199 HEARING EXHIBIT - 00000242

report that information immediately. Such information can be reported to the corporate security hotline anytime day or night at 888-694-6444.

V. Acknowledgment:

Suppliers must make their employees aware of this Policy and have Supplier employees acknowledge so in writing prior to beginning work at FPL Premises.

ECRC-08-3200
HEARING EXHIBIT - 00000243

Appendix HH – Acceptance Testing

HEARING EXHIBIT - 00000244

TURNKEY

ENGINEERING, PROCUREMENT AND CONSTRUCTION

AGREEMENT

FOR

SOLAR PHOTOVOLTAIC GENERATING FACILITY

BETWEEN

FLORIDA POWER & LIGHT COMPANY,
as FPL

AND

SUNPOWER CORPORATION, SYSTEMS,
as Contractor

Dated as of July 9, 2008

TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION

AGREEMENT FOR

SOLAR PHOTOVOLTAIC GENERATING FACILITY

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TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION
AGREEMENT
FOR
SOLAR PHOTOVOLTAIC GENERATING FACILITY

THIS TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT FOR SOLAR PHOTOVOLTAIC GENERATING FACILITY (this "Agreement"), dated as of July 9, 2008, is by and between FLORIDA POWER & LIGHT COMPANY, a Florida corporation (hereinafter called "FPL") and SunPower Corporation, Systems, a Delaware corporation (hereinafter called "Contractor").

W I T N E S S E T H:

WHEREAS, FPL wishes to construct and operate a solar photovoltaic generation facility with a minimum nominal capacity of 10 MW (net), and all services and utilities related thereto, all to be built on the Property Site (as hereinafter defined) located in Brevard County, Florida;

WHEREAS, Contractor has represented that it is experienced and qualified in providing technical assistance, licensing, engineering, procurement, supply, construction management, construction, commissioning, start-up and testing services, and that it possesses the requisite expertise and resources to complete the Work (as hereinafter defined);

WHEREAS, Contractor has agreed to provide, through itself or through Subcontractors and Vendors (as such terms are hereinafter defined), such Work on a "turn-key" basis for the Contract Price (as hereinafter defined); and

WHEREAS, Contractor has agreed to guarantee the timely and proper completion of the Work in strict accordance with the terms and conditions hereinafter set forth.

NOW, THEREFORE, in consideration of the foregoing premises, the mutual promises and covenants herein contained, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, FPL and Contractor hereby agree as follows:

ARTICLE I.
GENERAL MATTERS

1.1 DEFINED TERMS

As used in this Agreement, including the appendices, exhibits and other attachments hereto, each of the following terms shall have the meaning assigned to such term as set forth below:

1.1.1 "Affiliate" means, in relation to any Person, any other Person:

(a) Which directly or indirectly controls, or is controlled by, or is under common control with, such Person; or

(b) Which directly or indirectly beneficially owns or holds fifty percent (50%) or more of any class of voting stock or other equity interests of such Person; or

(c) Which has fifty percent (50%) or more of any class of voting stock or other equity interests that is directly or indirectly beneficially owned or held by such Person, or

(d) Who either holds a general partnership interest in such Person or such Person holds a general partnership interest in the other Person.

For purposes of this definition, the word "controls" means possession, directly or indirectly of the power to direct or cause the direction of the management or policies of a Person, whether through the ownership of voting securities or otherwise.

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1.1.2 "After-Tax Basis" means, with respect to any indemnity payment to be received by any Person, the amount of such payment (the base payment) supplemented by a further payment (the additional payment) to that Person so that the sum of the base payment plus the additional payment shall, after deduction of the amount of all Federal, state, and local income Taxes required to be paid by such Person in respect of the receipt or accrual of the base payment and the additional payment (taking into account any reduction in such income Taxes resulting from Tax benefits realized by the recipient as a result of the payment or the event giving rise to the payment), be equal to the amount required to be received. Such calculations shall be made on the basis of the highest generally applicable Federal, state, and local income tax rates applicable to the corporation for whom the calculation is being made for all relevant periods, and shall take into account the deductibility of state and local income taxes for Federal income tax purposes. The foregoing calculations shall be made by the recipient Person's third party tax advisors.

1.1.3 "Agreement" has the meaning set forth in the first paragraph hereof, as same may be amended, supplemented or modified from time to time in accordance with the terms hereof.

1.1.4 "Applicable Laws" means any act, statute, law, regulation, permit, license, ordinance, rule, judgment, order, decree, directive, guideline or policy (to the extent mandatory) or any similar form of decision or determination by, or any interpretation or administration of, any of the foregoing by any Government Authority with jurisdiction over the Plant, the Job Site, the performance of the Work or other services to be performed under the Contract Documents.

1.1.5 "Applicable Permits" means any and all permits, clearances, licenses, authorizations, consents, filings, exemptions, rulings or approvals from or required by any Government Authority that are necessary for the performance of the Work or ownership or use of the Work.

1.1.6 "Applicable Standards" means those sound and prudent practices, acts, methods, specifications, codes and standards of design, engineering, assembly, erection, installation, construction, performance, safety and workmanship prudently and generally engaged in or observed by the majority of the professional engineering and construction contractors performing engineering and construction services for major, grid-connected solar electric generating facilities in the United States that, in the exercise of good judgment, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, Applicable Permits, reliability, safety, environmental protection, local conditions, economy and efficiency. Notwithstanding the foregoing, the Work or any portion thereof shall meet specifications that are at least as stringent as those set forth in Appendix A, Scope of Work, and any other specifications set forth in this Agreement.

1.1.7 "Builder's Risk Policy" has the meaning set forth in Section 9.9.4, All Risk Installation and Builder's Risk Insurance, of Article IX, INSURANCE.

1.1.8 "Business Day" means any day other than a Saturday, Sunday or a legal holiday in Florida, United States.

1.1.9 "Capability Verification Test" means the test further described in Appendix HH, Performance Testing.

1.1.10 "Change In Law" means the (A) enactment, adoption, promulgation, modification, or repeal (in each case, after the date of this Agreement but before the date of Provisional Acceptance) of any Applicable Law of any Government Authority of (i) the State of Florida (or any city, county or municipality therein) or (ii) the Federal Government of the United States to the extent such federal law, directly affects the Work performed at the Property Site or (B) the modification after the date of this Agreement of any FPL Permit, and as to both (A) and (B) that establishes requirements that materially and adversely affect Contractor's costs or schedule for performing the Work; provided, however, a change in (x) any federal, state or local Tax law or any other law imposing a Tax, duty, levy, impost, fee, royalty, or charge for which Contractor is responsible hereunder, or (y) any Applicable Law affecting the cost of Contractor's or any Subcontractor's or Vendor's Labor, including increases in worker's compensation rates, shall not be a Change In Law pursuant to this Agreement.

1.1.11 "Change Order" has the meaning set forth in Section 6.1, CHANGE ORDER AT FPL'S REQUEST, of Article VI, CHANGE ORDERS.

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1.1.12 "Changes" has the meaning set forth in Section 6.1, CHANGE ORDER AT FPL'S REQUEST, of Article VI, CHANGE ORDERS.

1.1.13 "Commencement Date" means the date Contractor anticipates it will construct improvements at, or deliver materials to, the Job Site that may be insured pursuant to a builder's risk policy, as set forth in a written Notice delivered by Contractor to FPL pursuant to Section 5.1.1.

1.1.14 "Confidential Information" has the meaning set forth in Section 18.3, CONFIDENTIALITY, of Article XVIII, MISCELLANEOUS.

1.1.15 "Construction and Milestone Payment Schedule" means the schedule of construction/milestone completion installment payments of the Contract Price attached hereto as Appendix D.

1.1.16 "Contract Documents" means this Agreement and all appendices, exhibits incorporated into the Agreement (as set forth in Section 1.3, APPENDICES), as same may be amended, supplemented or modified from time to time in accordance with the terms hereof.

1.1.17 "Contract Price" means the total sum payable by FPL as stated in Section 7.1, Contract Price, for all labor, all materials, and all equipment, which sum shall be due in accordance with the terms of the Contract Documents as consideration for the timely performance of the Scope of Work to be performed by or through Contractor on a "turn-key" basis in order to complete the Project, all in strict accordance with the terms of the Contract Documents, which sum shall only be subject to adjustment in accordance with the Contract Documents, including but not limited to the adjustments contemplated in Appendix J, Option Pricing.

1.1.18 "Contractor" means SunPower Corporation, Systems, a Delaware corporation (as referenced in the opening paragraph hereof), and includes its legal successors and permitted assignees as may be accepted by FPL, in writing, pursuant to the terms of the Contract Documents.

1.1.19 "Contractor Deliverables" means each of the design criteria, system descriptions, manuals, Drawings, Final Plans, design calculations, quality assurance reports and all other material documents relating to the Project to be delivered to FPL in accordance with the requirements of the Contract Documents.

1.1.20 "Contractor Equipment" means all of the equipment, materials, apparatus, structures, tools, supplies and other goods provided and used by Contractor and its Subcontractors and Vendors for performance of the Work but which is not intended to be incorporated into the Plant.

1.1.21 "Contractor Event of Default" has the meaning set forth in Section 15.1, CONTRACTOR EVENTS OF DEFAULT, of Article XV, TERMINATION.

1.1.22 "Contractor Insurance Policies" has the meaning set forth in Section 9.1, CONTRACTOR INSURANCE POLICIES, of Article IX, INSURANCE.

1.1.23 "Contractor Parent Company" has the meaning set forth in Section 11.8, PARENT GUARANTY, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.24 "Contractor Parent Guaranty" has the meaning set forth in Section 11.8, PARENT GUARANTY, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.25 "Contractor Permits" means the Applicable Permits, other than FPL Permits, to be obtained by Contractor as described in Appendix A, Scope of Work, or otherwise required pursuant to the Contract Documents.

1.1.26 "Contractor Project Engineering Manager" means the person designated by Contractor as having the responsibility, authority and supervisory power of Contractor for the engineering and design of the Plant.

1.1.27 "Contractor Project Manager" means the person designated by Contractor as having the centralized responsibility, authority and supervisory power of Contractor for design, procurement, construction, testing and start-up of the Plant, as well as all matters relating to the administration of the provisions of the Contract Documents.

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1.1.28 "Contractor Site Manager" means an employee of Contractor, working under the supervision of the Contractor Project Manager, located at the Property Site on a daily basis.

1.1.29 "Contractor Taxes" has the meaning set forth in Section 3.24, CONTRACTOR TAXES, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.30 "Contractor's Representative" has the meaning given in Section 3.12, PROJECT MANAGEMENT AND CONTRACTOR'S REPRESENTATIVE, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.31 "Credit Trigger Event" shall be deemed to occur if, at the end of the most recently ended fiscal quarter of Contractor, Contractor fails to maintain a Tangible Net Worth of greater than $550,000,000.

1.1.32 "Credit Event of Default" shall be deemed to occur if, at the end of the most recently ended fiscal quarter of Contractor, Contractor fails to maintain a Tangible Net Worth of greater than $100,000,000.

1.1.33 "Credit Rating" means, on the date such rating is determined, the LC Issuing Bank's latest: (i) unsecured debt rating; (ii) corporate credit rating; or (iii) issuer rating.

1.1.34 "Critical Milestones" means the Milestones set forth in Appendix C, Critical Milestones and Milestones.

1.1.35 "Critical Parameters" has the meaning set forth in Section 3.19.7, Quality Assurance Program, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.36 "Critical Path" means a determination of the Project Schedule specifically illustrating those unique activities and durations that must be completed in sequence to complete the Work, which sequence shall be determined using critical path method precedence networking techniques applied by Contractor.

1.1.37 "Damages" has the meaning set forth in Section 16.1, CONTRACTOR INDEMNIFICATION, of Article XVI, INDEMNIFICATION.

1.1.38 "Day" or "day" means a period of twenty-four (24) consecutive hours from 12:00 midnight (Eastern time), and shall include Saturdays, Sundays and all holidays except that in the event a time period set forth in the Contract Documents expires on a Day that is not a Business Day, such period shall be deemed to expire on the next Business Day thereafter.

1.1.39 "Defect" means, any designs, engineering, software, drawings, components, tools, Equipment, installation, construction, workmanship or Work that, in FPL's reasonable judgment:

(a) Do not conform to the terms or requirements of the Contract Documents;

(b) Are not of uniform good quality, free from defects or deficiencies in design, application, manufacture or workmanship, or that contain improper or inferior workmanship; or

(c) Would adversely affect the:

(i) Performance of the Plant under anticipated operating conditions;

(ii) Continuous safe operation of the Plant during the Plant's design life;

(iii) Structural integrity of the Plant;

(iv) Economic value of FPL's investment in the Plant, all as determined by reference to Prudent Utility Practices.

Anything to the contrary notwithstanding, the Parties agree that Work shall be considered to be defective if it does not conform to Applicable Standards.

1.1.40 "Dispute" has the meaning set forth in Section 17.1, FRIENDLY CONSULTATION, of Article XVII, DISPUTE RESOLUTION.

1.1.41 "Drawings" means all:

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(a) Specifications, calculations, designs, plans, drawings, engineering and analyses, and other documents which determine, establish, define or otherwise describe the scope, quantity, and relationship of the components of the Plant, including the structure and foundation thereof; and

(b) Technical drawings, operating drawings, specifications, shop drawings, diagrams, illustrations, schedules and performance charts, calculations, samples, patterns, models, operation and maintenance manuals, piping and instrumentation diagrams, underground structure drawings, conduit and grounding drawings, lighting drawings, conduit and cable drawings, electric one-line's, electric schematics, connection diagrams and technical information of a like nature,

prepared or modified by Contractor or any of its Subcontractors or Vendors all of which are required to be delivered by Contractor, or any Subcontractor or Vendor, from time to time under the Contract Documents or at FPL's request which illustrates any of the Equipment or any other portion of the Work, either in components or as completed.

1.1.42 "Energy Yield Test" has the meaning set forth in Section 11.4.

1.1.43 "Environmental Control Program" means the environmental control program provided by FPL to Contractor.

1.1.44 "Environmental Plan" has the meaning set forth in Section 3.19.4, Health Plan, Safety Plan, and Environmental Plan, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.45 "Environmental Resource Plan" means the environmental resource plan prepared by FPL, which has been provided to Contractor prior to the date of the Agreement.

1.1.46 "Equipment" means all of the equipment, materials, apparatus, structures, tools, supplies, goods and other items provided by Contractor and its Subcontractors and Vendors that are installed or incorporated into the Plant or otherwise form or are intended to form part of the Work or the Plant (other than Contractor Equipment).

1.1.47 "Exempt Equipment" has the meaning set forth in Section 3.24.2, Exempt Equipment, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.48 "Expected Energy Output" has the meaning set forth in Section 2.1.2 of Appendix HH.

1.1.49 "Final Acceptance" means that all of the following have occurred as of the most recent applicable Tests:

(a) Provisional Acceptance has been achieved;

(b) The Tests, mechanical calibrations, electrical continuity and ground fault tests have been successfully completed and any Defects found have been corrected;

(c) Either the:

(i) Final Acceptance Performance Level specified in Section 11.3, FINAL ACCEPTANCE PERFORMANCE LEVEL; GUARANTEED PERFORMANCE LEVEL, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, has been met or exceeded as determined pursuant to Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES; or

(ii) Plant has achieved at a minimum the Minimum Performance Level as determined pursuant to Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, and (A) the Contract Price has been reduced in accordance with Section 10.5 for the percentage of the Final Acceptance Performance Level that has not been achieved and (B) Contractor has performed all Remediation Work requested by FPL related to any Work not associated with the percentage of the Final Acceptance Performance Level that has been achieved;

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(d) The Plant has been constructed in accordance with the Contract Documents and the Drawings;

(e) The Final Plans accurately reflect the Plant as constructed;

(f) The Plant is capable of being operated in a safe, normal, reliable and continuous manner in accordance with Applicable Laws and Applicable Permits (excluding for this purpose all variances or waivers of any Applicable Permits) and the Contract Documents at all operating conditions and modes specified in the Scope of Work;

(g) Contractor shall have delivered to FPL all operation and maintenance manuals and Final Plans in accordance with the Scope of Work;

(h) No defective or incomplete portions of the Work exist;

(i) Either:

(i) All items on the Punch List have been completed; or

(ii) The Parties have reached an agreement pursuant to Section 10.6, PUNCH LIST, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE, and Contractor has paid all amounts due to FPL pursuant thereto;

(j) All of Contractor's cleanup and related obligations have been completed;

(k) Any and all Liens in respect to the Plant, the Contract Documents, the Equipment, the Job Site or any fixtures, personal property or Equipment included in the Work created by, through or under, or as a result of any act or omission of, Contractor or any Subcontractor, Vendor or other Person providing labor or materials in connection with the Work shall have been released or bonded in form reasonably satisfactory to FPL;

(l) Contractor has delivered to FPL a Contractor's Lien Waiver and Release, in substantially the form of Appendix R, Form of Contractor Certificate for Final Waiver of Liens, from Contractor and Subcontractor's Certificate for Final Waiver of Liens in the form of Appendix R-1, Form of Subcontractor Certificate for Final Waiver of Liens, from each Substantial Subcontractor and Substantial Vendor;

(m) Contractor shall have paid all Schedule Liquidated Damages due under the Contract Documents, if any;

(n) All other outstanding obligations of Contractor hereunder that FPL has notified Contractor of shall have been satisfied; and

(o) FPL has approved of and signed the Final Acceptance Certificate pursuant to Section 10.8.

1.1.50 "Final Acceptance Certificate" means the certificate issued by FPL indicating that Final Acceptance has been achieved by Contractor.

1.1.51 "Final Acceptance Date" means the date of achievement of Final Acceptance as indicated in the Final Acceptance Certificate pursuant to Section 10.8, FINAL ACCEPTANCE OF THE PLANT, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE.

1.1.52 "Final Acceptance Performance Level" means that, at a minimum, the Actual Energy Output is equal to or greater than ninety-five percent (95%) of the Net Energy Output Guarantee when corrected to Guarantee Design Conditions, calculated as follows:

Actual Energy Output $\geq$ (0.95) * Net Energy Output Guarantee

Where "Actual Energy Output" has the meaning given in Section 2.1.2 of Appendix HH.

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1.1.53 "Final Acceptance Performance Level Date" has the meaning set forth in Section 11.4.1.

1.1.54 "Final Plans" means final Drawings and final specifications, as revised to reflect the changes during construction, and shall include as-built drawings, piping and instrumentation diagrams, underground structure drawings (including buried piping, all utilities, and critical hidden items), electric one-lines, electric schematics and connection diagrams.

1.1.55 "Financial Closing" means that all of the following events shall have occurred (which events may occur over a period of time) with respect to the Plant: (i) the Financing Documents have been fully executed (which documents may be executed over a period of time) which together provide for financing for the Plant in an amount and on the terms acceptable to FPL; (ii) all conditions precedent to the initial availability of funds under the Financing Documents referred to in the preceding clause (i) have been fulfilled or waived and the first draw thereunder has been made by FPL; and (iii) FPL has received commitments for such equity as is required by FPL and satisfies the requirements of the Financing Parties.

1.1.56 "Financing Documents" means all the loan agreements, notes, indentures, securities, debt instruments, bonds, security agreements, swap agreements, letters of credit and other documents or agreements with a Financing Party or relating to a financing (including refinancing) by a Financing Party.

1.1.57 "Financing Parties" means the lenders, security holders, investors, export credit agencies, multilateral institutions, equity providers and others providing debt or equity financing or refinancing to or on behalf of FPL or any Affiliate of FPL or for the Project or any portion thereof, or any trustee or agent acting on behalf of any of the foregoing.

1.1.58 "Force Majeure Event" has the meaning set forth in Section 14.1, DEFINITION OF FORCE MAJEURE EVENT, of Article XIV, FORCE MAJEURE AND FPL CAUSED DELAY.

1.1.59 "FPL" means Florida Power & Light Company, a Florida corporation (as referenced in the opening paragraph hereof) and it includes its legal successors and those assignees as may be designated by FPL, in writing, pursuant to the terms of this Agreement.

1.1.60 "FPL Caused Delay" means a material delay in Contractor's performance of any Critical Milestone, to the extent Contractor demonstrates that such delay was actually and demonstrably caused by FPL's failure to perform any covenant of FPL hereunder (other than by exercise of rights under this Agreement, including the exercise by FPL of the right to have defective or nonconforming Work corrected or re-executed), including, without limitation, FPL's failure to timely obtain any FPL Permit, and which actually, demonstrably and adversely affects the Critical Path. Contractor expressly acknowledges and agrees that any delay, to the extent caused by Contractor's action or inaction (other than by exercise of rights under this Agreement), is not an FPL Caused Delay.

1.1.61 "FPL Event of Default" has the meaning set forth in Section 15.6, FPL EVENTS OF DEFAULT, of Article XV, TERMINATION

1.1.62 "FPL Interconnection Facilities" shall have the meaning ascribed thereto in Section 2.3 of Appendix A, Scope of Work.

1.1.63 "FPL Permits" means the Applicable Permits to be obtained by FPL as set forth in Appendix A, Scope of Work.

1.1.64 "FPL Taxes" has the meaning set forth in Section 4.9, FPL TAXES, of Article IV, CERTAIN OBLIGATIONS OF FPL.

1.1.65 "GAAP" shall mean generally accepted accounting principles in the United States of America, consistently applied throughout the specified period.

1.1.66 "Government Authority" means any and all foreign, national, federal, state, county, city, municipal, local or regional (or equivalent) authorities, departments, bodies, commissions, corporations, branches, directorates, agencies, ministries, courts, tribunals, judicial authorities, legislative bodies, administrative bodies,

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regulatory bodies, autonomous or quasi-autonomous entities or taxing authorities or any department, municipality or other political subdivision thereof.

1.1.67 "Grid" means the interconnected high voltage transmission facilities being a part of the FPL transmission system.

1.1.68 "Guarantee Design Conditions" means Standard Test Conditions as such term is defined in the Scope of Work and Appendix HH.

1.1.69 "Guaranteed Performance Level" means the Net Energy Output Guarantee, as guaranteed by Contractor pursuant to Section 11.3, FINAL ACCEPTANCE PERFORMANCE LEVEL; GUARANTEED PERFORMANCE LEVEL, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.70 "Guaranteed Performance Test" means the test performed by Contractor in order to determine the Net Energy Output of the Plant, as more particularly described in Section 2.0 of Appendix HH, Acceptance Testing.

1.1.71 "Guaranteed Provisional Acceptance Date" means June 30, 2010, the date which Contractor guarantees that the Project shall achieve Provisional Acceptance, as such date may be extended in accordance with the terms hereof.

1.1.72 "Hazardous Material" means any hazardous or toxic chemicals, hazardous materials, hazardous waste, hazardous constituents, hazardous or toxic or radioactive substances or petroleum products (including crude oil or any fraction thereof) defined or regulated as such under any Applicable Laws.

1.1.73 "Health Plan" has the meaning set forth in Section 3.19.4, Health Plan, Safety Plan, and Environmental Plan, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.74 "Indemnified Person" has the meaning set forth in Section 16.3, CONDITIONS OF INDEMNIFICATION, of Article XVI, INDEMNIFICATION.

1.1.75 "Indemnifying Party" has the meaning set forth in Section 16.3, CONDITIONS OF INDEMNIFICATION, of Article XVI, INDEMNIFICATION.

1.1.76 "Independent Engineer" means the Person appointed by the Financing Parties and approved by FPL to ensure that the Work is completed in accordance with the Contract Documents.

1.1.77 "Initial LC Amount Expiration Date" has the meaning set forth in Section 7.5.1.

1.1.78 "Initial Site Mobilization" means the first instance when any of Contractor or its Subcontractors' or Vendors' Labor or other representatives is present on the Property Site after the date of this Agreement.

1.1.79 "Intangible Asset" means any asset that is treated as an intangible asset according to GAAP, including:

(a) goodwill, including any amounts (however designated on the balance sheet) representing the cost of acquisitions of subsidiaries in excess of underlying tangible assets;

(b) patents, trademarks and copyrights;

(c) leasehold improvements not recoverable at the expiration of a lease; and

(d) deferred charges (including, but not limited to, unamortized debt discount and expense, organization expenses and experimental and development expenses, but excluding prepaid expenses).

1.1.80 "Intellectual Property Rights" has the meaning set forth in Section 3.32, INTELLECTUAL PROPERTY RIGHTS, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.81 "Job Site" means the Property Site (other than the area designated as Protected Areas, if any, and not constituting a part of the Job Site on the survey provided by FPL pursuant to Section 4.7, DESCRIPTION OF PROPERTY SITE, of Article IV, CERTAIN OBLIGATIONS OF FPL) and any other areas where Contractor

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may temporarily obtain care, custody and control, use, easement or license for purposes directly, indirectly or incidentally related to performance of, or as an accommodation to, the Work.

1.1.82 "Labor" means the workforce of the relevant Person, including its staff and employee and non-employee and skilled and unskilled workers.

1.1.83 "Latest Notice to Proceed Date" has the meaning set forth in Section 5.2.4.

1.1.84 "LC Issuing Bank" means the domestic financial institution, acceptable to FPL and the Financing Parties and satisfying the requirements set forth in Section 7.5.3, LC Issuing Bank, of Article VII, CONTRACT PRICE; PAYMENTS TO CONTRACTOR, which institution will issue the Letter of Credit on behalf of Contractor in connection with the Project, as more particularly described in Section 7.5, LETTERS OF CREDIT, of Article VII, CONTRACT PRICE; PAYMENTS TO CONTRACTOR.

1.1.85 "Lease" means that certain Enhanced Use Lease, dated as of June 25, 2008, by and between FPL, as lessee, and the National Aeronautics and Space Administration, John F. Kennedy Space Center, as lessor.

1.1.86 "Letter of Credit" has the meaning set forth in Section 7.5, LETTERS OF CREDIT, of Article VII, CONTRACT PRICE; PAYMENTS TO CONTRACTOR.

1.1.87 "Lien" means any lien, security interest, mortgage, hypothecation, encumbrance or other restriction on title or property interest.

1.1.88 "Lift Stay Order" has the meaning set forth in Section 18.20, ACCEPTANCE OR REJECTION IN BANKRUPTCY, of Article XVIII, MISCELLANEOUS.

1.1.89 "Major Equipment" means any item or component, or set of items of components, of the Project with a value in excess of $250,000, the proper or efficient function of which materially affects the Plant's output or reliability.

1.1.90 "Major Manufacturers" means the manufacturers of the Major Equipment.

1.1.91 "Mechanical Completion" means that:

(a) The Equipment for the Project has been installed, including with the required connections and controls to produce electrical power;

(b) All Equipment related to the solar tracking system, if any, has been installed and checked for alignment, lubrication and rotation;

(c) All remaining electrical systems have been checked out and are ready for operation;

(d) All electrical continuity and ground fault tests and all mechanical tests and calibrations have been completed; and

(e) All instrumentation is operational and has been calibrated in accordance with manufacturers' standards and guidelines and, where possible, loop checked.

1.1.92 "Milestones" means the activities, events and targets, or combination thereof, set forth in Appendix C, Critical Milestones and Milestones, attached hereto.

1.1.93 "Minimum Performance Level" means that, at a minimum and as determined in Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, the Net Energy Output is equal to or greater than fifty percent (50%) of the Net Energy Output Guarantee when corrected to Guarantee Design Conditions.

1.1.94 "Module Warranty Period" has the meaning set forth in Section 12.1.4(c).

1.1.95 "Moody's" means Moody's Investor Services, Inc.

1.1.96 "Net Energy Output" means electrical energy of the Plant, in kWh, measured at the revenue quality meters at the FPL Interconnection Facilities.

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1.1.97 "Net Energy Output Guarantee" has the meaning set forth in Section 11.3, GUARANTEED PERFORMANCE LEVEL, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.98 "Noise Guarantee" means that the Project will function at a noise level that is equal to or less than the lower of the noise limitations set forth in Appendix A, Scope of Work, or the noise limitations contained in the Applicable Permits and Applicable Laws (as demonstrated by the Noise Test and excluding for purposes of determining compliance with the Applicable Permits and Applicable Laws all variances and waivers that may be applicable thereto).

1.1.99 "Noise Test" means the tests more particularly described in Appendix A, Scope of Work, which shall be performed simultaneously with the testing of the Minimum Performance Level and the Guaranteed Performance Level in order to evidence satisfaction of the Noise Guarantee for the Plant.

1.1.100 "Notice to Proceed" means the written notice given from FPL to Contractor directing Contractor to commence performance of the entire Work.

1.1.101 "Notice to Proceed Date" has the meaning set forth in Section 5.2.4.

1.1.102 "O&M Contractor" means the Person selected by FPL for the operation and maintenance of the Plant.

1.1.103 "O&M Personnel" has the meaning set forth in Section 3.22, TRAINING OF O&M PERSONNEL, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR

1.1.104 "Operating Guidelines" means the guidelines or requirements specified in the Utility interconnection agreement applicable to the Project.

1.1.105 "Operating Mode Test" means the test further described in Appendix A, Scope of Work.

1.1.106 "Parties" means collectively, FPL and Contractor.

1.1.107 "Party" means individually, FPL or Contractor.

1.1.108 "Payment Output Percentage" means the percentage determined in accordance with the following formula:

Payment Output Percentage = (1.2 x Output Percentage) - 20

Where:

Output Percentage = the percentage of the Guaranteed Performance Level achieved up to 95% (for purposes of Section 10.5.1) and 97% (for purposes of Section 11.4.3).

1.1.109 "Person" means an individual, partnership, corporation, limited liability company, company, business trust, joint stock company, trust, unincorporated association, joint venture, Government Authority or other entity of whatever nature.

1.1.110 "Plant" means the nominal 10 MW (net) solar photovoltaic, electrical generating facility, to be located on the Property Site, including the solar photovoltaic panels, the solar tracking system, if any, and all structures, facilities, appliances, lines, conductors, instruments, apparatus, components, roads and other equipment comprising and integrating the entire facility as more particularly described in Appendix A, SCOPE OF WORK.

1.1.111 "Plant Warranty Period" has the meaning set forth in Section 12.1.4(b).

1.1.112 "Pre-Existing Hazardous Material" means Hazardous Material that existed on or in the Property Site prior to Initial Site Mobilization by Contractor.

1.1.113 "Procedures Manual" has the meaning set forth in Section 3.19.3, Procedures Manual, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

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1.1.114 "Project" means the Plant and all equipment, services and utilities related thereto which must be designed, constructed, assembled, erected, commissioned, started, tested and otherwise completed by, or through, Contractor as part of the Scope of Work and in strict accordance with the provisions of the Contract Documents.

1.1.115 "Project Achievement Certificate" means a duly executed certificate in substantially the form of Appendix Q attached hereto, which is submitted by Contractor to FPL with a Request for Payment.

1.1.116 "Project Loss Manual" means the project loss manual prepared by FPL which has been provided to Contractor prior to the date of this Agreement.

1.1.117 "Project Schedule" means the schedule for completion of the Work attached hereto as Appendix B, Project Schedule.

1.1.118 "Property Site" means that certain piece of property located in Brevard County, Florida, as more particularly described in Appendix P, Legal Description of Property Site.

1.1.119 "Protected Areas" has the meaning set forth in Section 3.16.4, *Protected Areas*, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.120 "Provisional Acceptance" means that all of the following have occurred for the Project:

(a) Mechanical Completion has been achieved;

(b) The Plant has been synchronized with the Grid in accordance with the Scope of Work and the Utility's interconnection requirements;

(c) The Plant is capable of being operated safely, normally, reliably and continuously in accordance with the requirements of all Applicable Laws, Applicable Permits and the Contract Documents at all operating conditions and modes specified in the Scope of Work;

(d) The Project has achieved at a minimum the Minimum Performance Level as determined pursuant to Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES;

(e) The Project has achieved the Noise Guarantee simultaneously with the Minimum Performance Level;

(f) The Operating Mode Tests and the Capability Verification Tests have been successfully completed and all criteria for passing such tests have achieved;

(g) Contractor has provided FPL with copies of all Contractor Permits;

(h) The training of O&M Personnel has been completed;

(i) All spare parts required under the Contract Documents have been delivered by Contractor to the Property Site in accordance with Section 3.26, SPARE PARTS AVAILABILITY, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR;

(j) All Work has been completed in accordance with the requirements of the Contract Documents (other than items on the Punch List); and

(k) Contractor shall have paid all Schedule Liquidated Damages due under the Contract Documents, if any.

For the avoidance of doubt, it is expressly acknowledged and agreed that the commencement or completion of any stormwater system to be built in connection with the Project shall not be a condition to achieving Provisional Acceptance.

1.1.121 "Provisional Acceptance Date" means the actual date of achieving Provisional Acceptance as determined pursuant to Section 10.7, PROVISIONAL ACCEPTANCE, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE.

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1.1.122 "Prudent Utility Practices" means those sound and prudent practices, acts, methods, specifications, codes and standards generally followed by the United States electric utility industry with respect to design, construction, operation, and maintenance of first class, major electric generating, transmission, and distribution facilities (including but not limited to, the engineering, operating and safety practices generally followed by the electric utility industry) that, in the exercise of good judgment, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, Applicable Permits, reliability, safety, environmental protection, local conditions, economy and efficiency.

1.1.123 "Punch List" has the meaning set forth in Section 10.6, PUNCH LIST, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE.

1.1.124 "Qualified Insurer" has the meaning set forth in Section 9.3, QUALIFIED INSURERS, of Article IX, INSURANCE.

1.1.125 "Quality Assurance Program" has the meaning set forth in Section 3.19.7, Quality Assurance Program, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.126 "Quality Control Manual" has the meaning set forth in Section 3.19.7, Quality Assurance Program, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.127 "Remediation Work" means work required by FPL to remove all Work and Contractor Equipment from the Property Site and restore the Property Site to the condition of the Property Site immediately prior to Initial Site Mobilization.

1.1.128 "Remedial Plan" means a plan of corrective action, submitted by Contractor pursuant to Section 10.5, PERFORMANCE SHORTFALLS, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE, that specifies in reasonable detail the actions Contractor proposes to undertake to cause the Project to satisfy the Final Acceptance Performance Level, and the period of time in which Contractor proposes to complete the corrective action; provided that such corrective action is reasonably likely to cause the Project to satisfy the Final Acceptance Performance Level as determined by root cause analysis of the deficiencies identified by previous testing.

1.1.129 "Request for Payment" means the written requests from Contractor to FPL for payment hereunder, which requests shall be in substantially the form of Appendix F, Form of Request for Payment.

1.1.130 "S&P" means Standard and Poor's Ratings Group (a division of McGraw Hill Companies).

1.1.131 "Safe and Secure Workplace Policy" means the safe and secure workplace policy of FPL which is attached hereto as Appendix Z-1, Safe and Secure Workplace Policy, as same may be amended or modified by FPL from time to time.

1.1.132 "Safety Plan" has the meaning set forth in Section 3.19.4, Health Plan, Safety Plan and Environmental Plan, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

1.1.133 "Schedule Liquidated Damages" has the meaning set forth in Section 11.2, SCHEDULE LIQUIDATED DAMAGES, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

1.1.134 "Scheduled Synchronization Date(s)" means the date identified by Contractor in a notice received by FPL at least one hundred forty (140) days prior to such date as being the date on which Contractor will first attempt to cause the generating equipment of the Project to be electrically synchronized and connected to the Grid.

1.1.135 "Scope of Work" means the services and work to be provided, or caused to be provided, by or through Contractor under the Contract Documents for the Contract Price, as more particularly described in Appendix A, Scope of Work, as the same may be amended from time to time in accordance with the terms hereof, and which Scope of Work includes, without limitation, all licenses, Contractor Permits, technical assistance, engineering, assembly, construction management, construction, services, labor, materials,

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equipment, Contractor Equipment, operations and management that are indicated on, inferable from, or incidental to, the Contract Documents or the Drawings prepared in connection with the Contract Documents or that are likely to be required in accordance with Applicable Law, or that are properly and customarily included within the general scope and magnitude of the work incorporated into similar projects having similar output and performance requirements, all in order to produce a Project that complies with the requirements of the Contract Documents.

1.1.136 "Subcontractor" means any contractor, constructor or material man who performs any portion of the Scope of Work other than Contractor.

1.1.137 "Substantial Subcontractor" means a Subcontractor whose contract or contracts (in the aggregate) with Contractor require payments by Contractor totaling at least Two Hundred Fifty Thousand Dollars ($250,000.00).

1.1.138 "Substantial Vendor" means a Vendor whose contract or purchase orders (in the aggregate) with Contractor require payments by Contractor of at least Two Hundred Fifty Thousand Dollars ($250,000.00).

1.1.139 "Switchyard Facilities" means the area adjacent to the Plant designated by FPL for the 23 kV voltage equipment and apparatus used for connecting the Plant to the FPL Interconnection Facilities, all as more particularly described in Appendix A, Scope of Work.

1.1.140 "Tangible Net Worth" with respect to any Person means such Person's total stockholder's equity minus its Intangible Assets, each as would be reflected on a balance sheet prepared in accordance with GAAP.

1.1.141 "Tax" or "Taxes" means all fees, taxes, including sales taxes, use taxes, stamp taxes, value-added taxes, ad valorem taxes and property taxes (personal and real, tangible and intangible), customs, duties, tariffs, levies, assessments, withholdings and other charges and impositions of any nature, plus all related interest, penalties, fines and additions to tax, now or hereafter imposed by any Applicable Law or Government Authority (including penalties or other amounts payable pursuant to subtitle B of Title I of ERISA).

1.1.142 "Termination Payment" has the meaning set forth in Section 15.3.2, Termination Payment, of Article XV, TERMINATION.

1.1.143 "Termination Payment Schedule" means Appendix N hereto.

1.1.144 "Test Notice" has the meaning set forth in Section 10.1.2, Test Notice, of Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE

1.1.145 "Tests" means the Operating Mode Test, the Capability Verification Test, the Guaranteed Performance Test and the Noise Test.

1.1.146 "Utility" means FPL.

1.1.147 "Vendor" means any supplier, manufacturer or vendor of Equipment to Contractor or any Subcontractor.

1.1.148 "Warranty Period" and "Warranty Periods" have the meanings set forth in Section 12.1.4, Warranty Period, of Article XII, CONTRACTOR'S WARRANTIES.

1.1.149 "Work" has the meaning set forth in Section 3.1, SCOPE OF WORK; APPLICABLE STANDARDS, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, and includes the Plant, the Equipment, the Contractor Deliverables and any other product or result of the Work, but excludes any storm water system at or related to the Project Site.

1.2 INTERPRETATION

Unless the context of the Contract Documents otherwise requires:

1.2.1 The headings contained in this Agreement are used solely for convenience and do not constitute a part of this Agreement between the Parties, nor should they be used to aid in any manner to construe or interpret this Agreement;

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1.2.2 The gender of all words used herein shall include the masculine, feminine and neuter and the number of all words shall include the singular and plural words;

1.2.3 The terms "hereof", "herein" "hereto" and similar words refer to this entire Agreement and not to any particular Article, Section, Appendix or any other subdivision of this Agreement;

1.2.4 References to "Article," "Section" or "Exhibit" are to this Agreement unless specified otherwise;

1.2.5 Reference to "this Agreement" (including any Appendix hereto) or any other agreement, Exhibit, permit or document shall be construed as a reference to such agreement or document as the same may be amended, modified, supplemented or restated, and shall include a reference to any document which amends, modifies, supplements or restates, or is entered into, made or given pursuant to or in accordance with its terms;

1.2.6 References to any law, statute, rule, regulation, notification or statutory provision (including Applicable Laws, Applicable Permits and the Operating Guidelines) shall be construed as a reference to the same as it may have been, or may from time to time be, amended, modified or re-enacted;

1.2.7 References to any Person shall be construed as a reference to such Person's successors and permitted assigns; and

1.2.8 References to "includes," "including" and similar phrases means "including, without limitation."

1.3 APPENDICES

The following Appendices are attached to and incorporated into and made a part of this Agreement:

1.3.1 Appendix A ..... Scope of Work

1.3.2 Appendix B..... Project Controls Requirements

1.3.3 Appendix C..... Critical Milestones and Milestones

1.3.4 Appendix D ..... Construction and Milestone Payment Schedule

1.3.5 Appendix E..... Credit Trigger Event

1.3.6 Appendix F..... Form of Request for Payment

1.3.7 Appendix G ..... Form of Final Acceptance Certificate

1.3.8 Appendix H ..... Form of Contractor Certificate for Partial Waiver of Liens

1.3.9 Appendix H-1 ..... Form of Subcontractor Certificate for Partial Waiver of Liens

1.3.10 Appendix I..... Form of Contractor Parent Guaranty

1.3.11 Appendix J..... Option Pricing

1.3.12 Appendix K ..... Module Warranty

1.3.13 Appendix L..... Operating and Maintenance Manuals

1.3.14 Appendix M..... FPL Permits

1.3.15 Appendix N ..... Termination Payment Schedule

1.3.16 Appendix O ..... Project Management Team

1.3.17 Appendix P..... Legal Description of Property Site

1.3.18 Appendix Q ..... Form of Project Achievement Certificate

1.3.19 Appendix R..... Form of Contractor Certificate for Final Waiver of Liens

1.3.20 Appendix R-I..... Form of Subcontractor Certificate for Final Waiver of Liens

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1.3.21 Appendix S ..... Form of Request for Change Order

1.3.22 Appendix T ..... Intentionally Deleted

1.3.23 Appendix U ..... Form of Letter of Credit

1.3.24 Appendix V ..... Contractor's Exclusions

1.3.25 Appendix W ..... Intentionally Deleted

1.3.26 Appendix X ..... Intentionally Deleted

1.3.27 Appendix Y ..... Form of Quality Assurance Programs

1.3.28 Appendix Z ..... Form of Safety Plan

1.3.29 Appendix Z-1 ..... Safe and Secure Workplace Policy

1.3.30 Appendix HH ..... Acceptance Testing

1.3.31 Appendix II ..... Performance Degradation Testing

1.4 ORDER OF PRECEDENCE

1.4.1 In the event of conflicts among the terms of the Contract Documents, interpretations shall be based upon the following Contract Documents which are set forth in ranked order of precedence:

(a) Amendments, addenda or other modifications to the Contract Documents (including Change Orders) duly signed and issued after the signing of this Agreement and effected in accordance with the terms hereof, with those of a later date having precedence over those of an earlier date;

(b) The Agreement; and

(c) The Appendices to the Agreement.

In the event of a conflict among, or within, any other Contract Document(s) within any one of the levels set forth in the foregoing order of precedence, or between the Contract Documents and Applicable Laws or Applicable Permits, or among Applicable Laws or Applicable Permits themselves, the more stringent or higher quality requirements shall control. All obligations imposed on Contractor and each Subcontractor under the Agreement or under Applicable Laws, Applicable Permits or Applicable Standards and not expressly imposed or addressed in the Contract Documents shall be in addition to and supplement the obligations imposed on Contractor under the Contract Documents, and shall not be construed to create an "irreconcilable conflict."

1.5 LANGUAGE

1.5.1 The Contract Documents and all documentation to be supplied hereunder (including, without limitation, all Contractor Deliverables and all warranties provided hereunder) shall be in the English language.

ARTICLE II.
RETENTION OF CONTRACTOR

2.1 RETENTION OF CONTRACTOR

FPL hereby engages Contractor, and Contractor hereby agrees to be engaged by FPL to perform the Work in accordance with the terms and conditions set forth herein.

2.2 STATUS OF CONTRACTOR; NO PARTNERSHIP

Contractor shall be an independent contractor with respect to any and all Work performed and to be performed under the Contract Documents. The Contract Documents shall not be interpreted or construed to create an association, joint venture or partnership relationship among or between the Parties or any similar relationship, obligations or liabilities. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, act on behalf of, or to act as or be an agent or representative of, or to otherwise bind or obligate the other Party.

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2.3 SUBCONTRACTORS AND VENDORS.

2.3.1 Subject to the terms hereof, Contractor shall have the right to have any portion of the Work performed by a Subcontractor or Vendor qualified to perform such Work pursuant to written subcontracts or written purchase orders; provided that Contractor shall not be relieved from any liability or obligation under the Contract Documents. Except as otherwise expressly provided in the Contract Documents, Contractor shall be solely responsible for engaging, managing, supervising and paying all such Subcontractors and Vendors. Contractor shall require that all Work performed, and all Equipment provided by Subcontractors and Vendors are received, inspected and otherwise furnished in accordance with the Contract Documents, and Contractor shall be solely liable for all acts, omissions, liabilities and Work (including Defects therein) of such Subcontractors and Vendors. FPL shall not have any obligation or liability to any Subcontractor or Vendor. Nothing in any contract, subcontract or purchase order with any Subcontractor or Vendor shall in any way diminish or relieve Contractor from any duties and obligations under the Contract Documents; and each such contract, subcontract and purchase order must provide that the rights thereunder are assignable to FPL and the Financing Parties or their designees at any time without the prior consent of the applicable Subcontractor or Vendor. No Subcontractor or Vendor is intended to be or shall be deemed a third-party beneficiary of the Contract Documents.

2.3.2 FPL shall have the right to approve, in advance in writing, each Substantial Subcontractor and Substantial Vendor in accordance with the terms hereof. Prior to retaining any Substantial Subcontractors or Substantial Vendors, Contractor shall notify FPL in writing and provide it with such information as necessary to enable FPL to evaluate each such proposed Substantial Subcontractor or Substantial Vendor for the portion of the Work proposed to be performed by it. Within fifteen (15) days after receipt of such information, FPL shall advise Contractor if any proposed Substantial Subcontractor or Substantial Vendor is unacceptable. If FPL fails to object to any proposed Substantial Subcontractor or Substantial Vendor within such fifteen (15) day period, Contractor may retain such Substantial Subcontractor or Substantial Vendor for the portion of the Work proposed. If FPL objects in writing (stating with reasonable detail the basis for such objection) within such fifteen (15) day period to such proposed Substantial Subcontractor or Substantial Vendor, Contractor shall not retain such proposed Substantial Subcontractor or Substantial Vendor. Approval of any Substantial Subcontractor or Substantial Vendor under this paragraph shall only be for the portion of the Work so approved. Contractor hereby acknowledges and agrees that the review and/or acceptance of any subcontract by FPL and the acceptance of the approved Substantial Subcontractors and Substantial Vendors shall not: (i) modify, in any way, the obligations of Contractor pursuant to the Contract Documents; or (ii) be raised as a claim or as a defense or counterclaim to any claim in connection with the Contract Documents.

2.3.3 Contractor shall submit to FPL a copy of each purchase order or agreement entered into with a Substantial Subcontractor or Substantial Vendor for Major Equipment. Each purchase order or agreement shall show, where applicable, the Vendor's or Subcontractor's name, manufacturer's name, materials type, model number, size, quantity and lists of the Major Equipment ordered, and shall be submitted to FPL when issued for purchase. For purposes of clarity, it is understood and agreed that no document required to be submitted to FPL pursuant to this Section 2.3.3 shall be required to contain any economic terms, all of which economic terms may be redacted prior to submission to FPL.

2.3.4 Each subcontract and purchase order shall require such Subcontractor and Vendor to assume toward Contractor those terms and conditions of contracting which Contractor customarily includes in its subcontracts. At a minimum, all subcontracts shall require the Subcontractors to comply with Applicable Laws and Applicable Permits, shall provide that FPL has the right of inspection as provided hereunder and require such Subcontractors and Vendors to:

(a) Be subject to the labor obligations hereunder as well as the safety and security provisions of the Contract Documents;

(b) Provide guarantees and warranties with respect to its portion of the Work and the Equipment,

(c) Provide certificates of insurance as set forth herein;

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(d) Be subject to the dispute resolution procedures as required herein; and

(e) Have such terms and conditions as are reasonably and customarily obtained.

All subcontracts shall preserve and protect the rights of FPL, shall not prejudice such rights and shall require each Subcontractor to enter into similar agreements with other Subcontractors.

2.3.5 In addition to the requirements set forth in Section 2.3.4, above, Contractor shall include in each subcontract and purchase order the following language to make FPL an express third-party beneficiary of such subcontract or purchase order:

> "The parties hereto agree and acknowledge that the services/work/equipment to be provided hereunder by [subcontractor] will be incorporated into the power station being developed by [FPL]. As such, the parties expressly agree that FPL is a third party beneficiary of this [Agreement] entitled, in its own name or in the name of [Contractor], to enforce this [Agreement] against [subcontractor]."

ARTICLE III.
CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR

3.1 SCOPE OF WORK; APPLICABLE STANDARDS.

3.1.1 Contractor shall, at its own cost and expense:

(a) Design, engineer, procure, construct, start up, and carry out the Tests for the Plant, and perform its other obligations hereunder, including completion of the Scope of Work and any warranty work hereunder; and

(b) Manage, supervise, inspect and furnish all Labor, Equipment, Contractor Equipment, temporary structures, temporary utilities, products and services for the foregoing,

all on a turnkey basis, in accordance with the Contract Documents, including, without limitation, the Project Schedule and the Scope of Work, as the same may be modified from time to time in accordance with the terms hereof by a Change Order or other amendment hereto (all of the foregoing being collectively referred to in this Agreement as the "Work").

3.1.2 Subject to the remedies provided for herein, Contractor shall perform the Work and turn the Plant over to FPL in a manner that is:

(a) Sufficient, complete and adequate in all respects necessary for the Project to successfully achieve Provisional Acceptance by the Guaranteed Provisional Acceptance Date;

(b) In conformance with professional standards and skill, expertise and diligence of design and construction professionals regularly involved in first class, major grid-connected solar power projects in the United States;

(c) In compliance with the terms of the Contract Documents, the Operating Guidelines, the Utility's interconnection requirements, all Applicable Laws, Applicable Standards and Applicable Permits; and

(d) Approved as to form, use and content by all Government Authorities and private entities authorized to administer or enforce any building or construction code or standard whose approval of the final design of the Plant, or any portion thereof, is necessary for the construction, operation or interconnection of the Plant.

3.1.3 *Contractor's Exclusions*. In light of the foregoing, Contractor has included within the Contract Price the cost to complete the entire Scope of Work. Items need not be specifically listed in the Contract Documents or in Appendix A, Scope of Work, in order to be deemed to be items within the Scope of Work. It is understood that Contractor is better qualified to list exclusions than FPL is to list inclusions. Therefore,

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any item indicated on the Contract Documents, inferable therefrom, incidental thereto or required in accordance with any Applicable Law, Applicable Standards, Applicable Permits or Prudent Utility Practices, that is not specifically excluded from the Scope of Work in Contractor's exclusions set forth on Appendix V, Contractor's Exclusions, is to be considered as part of the Scope of Work. In addition, the Scope of Work includes all that should be properly included and all that would be customarily included within the general scope and magnitude of the Work in order to achieve the Guaranteed Performance Level applicable to the Project. As a result, except for Contractor's exclusions set forth on Appendix V, Contractor's Exclusions, Contractor hereby waives any and all claims for an increase in the Contract Price or an extension of the Guaranteed Provisional Acceptance Date based, in whole or in part, upon an assertion that any certain license, technical assistance, engineering, assembly, construction, service, labor, material, equipment, operation or management is beyond the Scope of Work when such license, technical assistance, engineering, assembly, construction, service, labor, material, equipment, operation or management is indicated in the Contract Documents, the Drawings or other instruments of service prepared in connection with the Contract Documents, inferable therefrom, incidental thereto, required in accordance with any Applicable Law, Applicable Standards, Applicable Permits, Prudent Utility Practices or otherwise necessary in order to complete a Project in accordance with and subject to the requirements of the Contract Documents.

3.1.4 Contractor shall perform the Work in conformance with professional standards and skill, expertise and diligence of design and construction professionals regularly involved in first class, major, grid-connected solar power projects for public utilities in the United States. Without limiting the generality of the foregoing, Contractor shall:

(a) Comply with, and shall cause the Work and all components thereof to comply with, the Operating Guidelines, Applicable Laws, Applicable Standards, Applicable Permits, Prudent Utility Practices, the requirements of the Contract Documents and the generally accepted standard of care, skill and diligence as would be provided by, in the case of engineering services, a prudent engineering firm, and in the case of construction or procurement services, by a prudent construction firm, in each case experienced in supplying such services in the United States to power-producing entities for first class, major power projects;

(b) Cause the Work to be performed with Contractor's best skill and judgment, in a safe, expeditious, good and workmanlike manner in accordance with the preceding paragraph (a);

(c) Cause the Work to be approved as to form, use and content by all Government Authorities and private entities authorized to administer or enforce any building or construction code or standard whose approval of the final design of the Project, or any portion thereof, is necessary for the construction or operation of the Project;

(d) Cause the Plant to be designed to operate, and shall cause the Plant to be capable of being operated, at all levels and operating modes in accordance with the Operating Guidelines, Applicable Laws, Applicable Standards, Applicable Permits, Prudent Utility Practices and the requirements of the Contract Documents; and

(e) Cause the Plant and all items of Equipment and improvements comprising the Plant to be designed, manufactured, installed, calibrated and tested where applicable in accordance with the published standards (as of the dates specified) of the organizations listed in the Scope of Work and Contractor shall notify FPL of any standards of such organizations that are inconsistent with each other and advise FPL of the manner in which it intends to resolve such inconsistency in accordance with the published standard.

Contractor shall inspect or cause to be inspected all items to be incorporated into or used in the performance of the Work and shall reject those items determined not to be in compliance with the requirements of the Contract Documents. Except as otherwise expressly provided in this Agreement, the standard of performance set forth in this Section 3.1.4, shall apply to all aspects of the Work, and this Section 3.1.4, shall be deemed to be incorporated by reference into each provision of the Contract Documents describing the Work, Contractor's obligations hereunder, or referring to the "requirements of

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the Contract Documents", "in accordance with the Contract Documents" or words of similar effect. In no event will references in any provision of Contract Documents to one or more of the standards, guidelines, practices, regulations, laws, or permits contained in this Section 3.1.4, be interpreted to limit in the applicability of all such standards, guidelines, practices, regulations, laws, and permits to such provision. Additionally, as a condition to meeting Provisional Acceptance and Final Acceptance, the Work for such milestone must be completed in accordance with all of the standards, guidelines, practices, regulations, laws, and permits contained in this Section 3.1.4.

3.1.5 Contractor acknowledges that this Agreement constitutes, subject to the terms hereof, a fixed price obligation to:

(a) Engineer, design, procure, construct, test and start up through Provisional Acceptance a turnkey Project, complete in every detail, within the time and for the purpose designated herein;

(b) Achieve Final Acceptance within the time designated herein;

(c) Comply with all of the warranty obligations set forth in this Agreement; and

(d) Perform Contractor's other obligations hereunder.

References to the obligations of Contractor under this Agreement as being "turnkey" and performing the Work on a "turnkey basis" means that Contractor is obligated to supply all of the Equipment and design services, install all of the Equipment and supply all labor and to supply and perform all of the Work, in each case as may reasonably be required, necessary, incidental, or appropriate (whether or not specifically set forth in this Agreement) to complete the Work such that the Project satisfies the applicable terms, conditions, and Contractor's obligations concerning the Guaranteed Performance Level and other guarantees and requirements set forth in this Contract Documents, all for the Contract Price.

3.2 CONTROL AND METHOD OF THE WORK.

3.2.1 Subject to the terms hereof, Contractor shall be solely responsible for performing or causing to be performed the Work in accordance with the terms of the Contract Documents, and for all means, methods, techniques, sequences, procedures, and safety and security programs in connection with such performance. Contractor shall inform FPL in advance concerning its plans for carrying out the Work.

3.2.2 Whenever the words "as ordered," "as directed," "as required," "as permitted," "as allowed," "approved," "reasonable," "suitable," "acceptable," "properly," "satisfactory," or words or phrases of similar effect and import are used, it shall be understood that none of such terms shall imply that FPL has any authority over, right to control or responsibility for supervision of Contractor or its Subcontractors or Vendors, such supervision (including sole control over and responsibility therefor) being strictly reserved for Contractor. Any method of Work suggested by FPL that is used by Contractor will be used at the risk and responsibility of Contractor, and FPL will assume no responsibility therefor.

3.3 COMPLIANCE WITH LAW

Contractor shall comply, and shall cause all of its Subcontractors, Vendors and Persons that it has a right to direct who are engaged in the performance of any of the Work to comply with, all Applicable Laws and Applicable Permits. Contractor shall perform the Work in a manner designed to protect the environment on and off the Job Site and minimize damage or nuisance to Persons and property of the public or others, including damage or nuisance resulting from pollution, noise or other causes arising as a consequence of methods of construction or operation of the Plant. The foregoing shall not be construed as to limit Contractor's obligations and liabilities under Section 3.15, PROTECTION AND SAFETY, below.

3.4 CERTAIN MATTERS PERTAINING TO JOB SITE.

3.4.1 *Project Inspection.* Contractor acknowledges that, prior to the date of this Agreement, Contractor:

(a) Has made a complete and careful examination of the Job Site and the surrounding areas, drawings and specifications and other information set forth in the Contract Documents;

(b) Has made a complete and careful examination to determine the difficulties and hazards incident to the performance of the Work, including:

(i) The location of the Project;

(ii) The proximity of the Project to adjacent facilities and structures;

(iii) The conditions of the roads and waterways in the vicinity of the Job Site, including the conditions affecting shipping and transportation, access, disposal, handling and storage of materials;

(iv) The nature and character of the soil, terrain, surface and subsurface conditions of the Job Site;

(v) The labor conditions in the region of the Job Site;

(vi) Applicable Laws and Applicable Permits;

(vii) Rights of FPL regarding the Job Site as set forth herein;

(viii) The local weather conditions based upon previous weather data;

(ix) The qualifications of all Subcontractors and Vendors;

(x) The Safe and Secure Workplace Policy, the Project Loss Manual and Environmental Control Program; and

(xi) All other known matters and other matters that Contractor should know under Applicable Standards that might affect Contractor's performance under this Agreement or the design, engineering, procurement, construction, start-up, demonstration and testing of the Plant; and

(c) Has determined to Contractor's satisfaction the nature and extent of such difficulties and hazards.

3.4.2 *Responsibility for Interpreting Sub-Surface Data*. Notwithstanding the above, where FPL has made investigations of subsurface conditions in areas where Work is to be performed under this Agreement, such investigations are made by FPL for the purpose of study and design. To the extent the records of such investigation are included in this Agreement, the interpretation of such records shall be the sole responsibility of Contractor. FPL assumes no responsibility whatsoever with respect to the sufficiency or accuracy of such investigations, the records thereof, or of the interpretations set forth and there is no warranty or guarantee, either express or implied, that the conditions indicated by such investigations or records thereof are representative of those existing throughout such areas, or any part thereof, or that unforeseen developments may not occur, or that materials other than or in proportions different from those indicated may not be encountered.

3.4.3 In light of the foregoing and subject to Section 3.4.4, Differing Condition, Contractor accepts the Job Site in its existing condition and waives any right to additional compensation beyond the Contract Price or an extension of the Guaranteed Provisional Acceptance Date, and any other claims that may arise due, in whole or in part, to errors or omissions in, or inconsistencies among, the Contract Documents and any information provided in connection with the Project. Contractor shall be solely responsible for performing any preliminary Work on the Job Site necessary for the commencement of construction to occur, including removal of all physical impediments to performing Work on the Job Site, above and below ground.

3.4.4 *Differing Condition*. Notwithstanding the acknowledgments set forth in Section 3.4.1, no less than sixty (60) days prior to commencement of Contractor's mobilization on the Job Site (the "Geotechnical Investigation Completion Date"), Contractor may conduct a geotechnical investigation in the location of the Job Site or any portion thereof as Contractor reasonably deems necessary to confirm the site conditions referred to in Sections 3.4.1, and 3.4.2, above. If as a result of the geotechnical investigation, Contractor:

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(a) Encounters any concealed subsurface conditions which a reasonable, experienced Contractor would not foresee existing at the Job Site and which vary materially from the conditions shown in the Contract Documents; and

(b) Any such condition causes a material increase or decrease in the Contract Price or time required for performance of the Work or otherwise materially affects any provision of this Agreement,

then Contractor shall notify FPL thereof and FPL may either:

(i) Issue a Change Order to address such condition; or

(ii) Terminate this Agreement pursuant to Section 15.3.

Contractor specifically waives the right to make any such claims after the Geotechnical Investigation Completion Date. Except as set forth in this Section 3.4.4, Contractor assumes the risk of surface and subsurface conditions at the Job Site and shall not be entitled to an extension of the Project Schedule or an increase in the Contract Price.

3.5 FPL ACCESS TO JOB SITE

Subject to Contractor's reasonable safety policies, FPL shall have the right to have representatives on the Job Site full time. In addition, Contractor shall provide reasonable access to the Job Site and the Work at all times to FPL, FPL's other contractors, the Independent Engineer and the Financing Parties and their respective employees, representatives, agents and consultants, subject to Contractor's reasonable safety policies.

3.6 INSPECTION AND TESTING OF WORK IN PROGRESS.

3.6.1 Each item of Equipment to be supplied by Contractor shall be subject to inspection and testing during and upon completion of its fabrication and installation in accordance with the provisions of the Scope of Work. Without limiting the foregoing, Contractor shall be responsible for inspection and testing of the Equipment in accordance with Applicable Standards.

3.6.2 Contractor shall perform inspection, expediting, quality surveillance and traffic services as are required for performance of the Scope of Work. Contractor shall perform such detailed inspection of Work in progress at intervals appropriate to the stage of construction or fabrication of the Project as is necessary to ensure that such Work is proceeding in accordance with this Agreement and the Contract Documents and to protect FPL against Defects and deficiencies in such Work. At least fifteen (15) Business Days prior to the time Contractor or its representative intends to inspect any item of Major Equipment, Contractor shall notify FPL in writing of such inspection which notice shall state the date, time and place where such inspection is to be conducted (provided that, if the inspection will occur at a location outside of the United States of America, Contractor shall provide such notice as soon as possible but in no event less than fifteen (15) Business Days prior to such inspection). FPL and/or its designated agent may, at FPL's option, accompany Contractor to the inspection by notifying Contractor in writing within five (5) Business Days of receipt of notice of the inspection. FPL's failure to notify Contractor within the permitted time period shall be deemed to be a decision by FPL not to attend the inspection. Contractor shall arrange for access to the manufacturer's facilities to permit any such inspection to be conducted smoothly. Contractor shall reimburse FPL for any costs necessarily and reasonably incurred by FPL due to Contractor's failure to prepare any portion of the Work for inspection or testing after having provided notice to FPL of any such inspection or test. With respect to any inspection that FPL chooses not to attend, Contractor shall:

(a) Keep FPL informed in all material respects of the progress and quality of all work;

(b) Advise FPL of any deficiencies revealed through such inspections and of the measures proposed by Contractor to remedy such deficiencies in order to avoid any delay in the completion of the Work and Contractor's performance of the Work; provided that, any such notice provided pursuant to this Section 3.6.2, shall not constitute a request for adjustment, extension or modification of the Project Schedule or FPL's consent to any of the same; and

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(c) Upon FPL's request, provide FPL with a reasonable opportunity to review Contractor's records with respect to such inspections. Contractor shall include the right to inspection by FPL or its representative in all subcontracts and purchase orders.

3.6.3 Contractor shall permit FPL and, as authorized by FPL, any Person designated by FPL, and the Financing Parties to inspect, test and observe the Work from time to time; provided, however, that none of such Persons shall have any authority or responsibility for such Work. Contractor shall provide FPL each month during performance of the Work with a schedule of all testing proposed for the following three (3) month period in compliance with the requirements of the Scope of Work.

3.7 NO WAIVER OF RESPONSIBILITY

No inspection made, acceptance of Work, payment of money or approval given by FPL, the Financing Parties or the Independent Engineer shall relieve Contractor of its obligations for the proper performance of the Work in accordance with the terms hereof. Subject to the limitations of Article XII, Contractor's Warranties, FPL may reject any Work with Defects or which is not in accordance with the requirements of the Contract Documents, regardless of the stage of completion, the time or place of discovery of error, and whether FPL previously accepted any or all of such Work through oversight or otherwise. Except with respect to the achievement of Provisional Acceptance and Final Acceptance, no approval given by FPL, in and of itself, shall be considered as an assumption of risk or liability by any such Person. Any such approval shall mean that the Person giving the approval has no objection to the adoption or use by Contractor of the matter approved at Contractor's own risk and responsibility. Contractor shall have no claim relating to any such matter approved, including any claims relating to the failure or inefficiency of any method approved.

3.8 DEFECTIVE WORK

3.8.1 Prior to Provisional Acceptance, Contractor shall at its own cost and expense correct or replace any Work that contains a Defect, or is not otherwise in accordance with the Contract Documents. Equipment that has been replaced, if situated on the Job Site, shall be removed by Contractor from the Job Site at Contractor's own cost and expense.

3.8.2 If Contractor or any Subcontractor defaults or neglects to carry out the Scope of Work in accordance with the Contract Documents and Contractor fails within a reasonable period of time (as reasonably determined by FPL) after it knows or should have known of such default or neglects to commence and continue correction of such default or neglect with diligence and promptness, FPL may, without prejudice to other remedies FPL may have under this Agreement, correct such deficiencies. In such event, an appropriate Change Order shall be issued deducting from payments then or thereafter due to Contractor the reasonable cost of correcting such deficiencies, including reasonable compensation for the costs to enforce this provision (including reasonable attorneys' fees) and any consultant's additional services and reasonable expenses made necessary by such default, neglect or failure. If payments then or thereafter due to Contractor are not sufficient to cover such amounts, Contractor shall pay the difference to FPL within three (3) days from FPL's request therefor.

3.8.3 Contractor shall correct any and all deficiencies as required by the Contract Documents notwithstanding any actual or possible legal obligation or duty of a Subcontractor concerning same and nothing contained in this Section shall modify Contractor's obligation to achieve Final Acceptance in accordance with the Contract Documents.

3.9 CLEAN-UP.

3.9.1 Without limiting the provisions of Section 3.16, ENVIRONMENTAL MATTERS, Contractor shall at all times keep the Job Site reasonably free from waste, rubbish and Hazardous Material, other than Pre-Existing Hazardous Material, relating to its Work. Contractor shall maintain the Job Site in a neat and orderly condition throughout the performance of the Work. Contractor shall employ sufficient personnel to clean its office and FPL's office at the Job Site and work areas each working day and shall cooperate with the other Persons working at the Job Site to keep the Job Site clean.

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3.9.2 Prior to the Final Acceptance Date or as soon as practicable after the termination of this Agreement by FPL in accordance with the provisions of Article XV, TERMINATION, Contractor shall:

(a) Remove all Contractor Equipment from the Job Site (other than equipment, supplies and materials necessary or useful to the operation or maintenance of the Plant and Equipment and equipment, supplies and materials directed by FPL to remain at the Job Site until completion of the Plant);

(b) Clean out all pits, pipes, chambers and conduits;

(c) Tear down and remove all temporary structures on the Job Site built by it or its Subcontractors and restore such areas to a condition consistent with that of a newly constructed photovoltaic solar power plant, except as required by Applicable Law, Section 3.16.4, Protected Areas, or any other provision of this Agreement; and

(d) Remove all waste, rubbish and Hazardous Material from and around the Job Site, except that Contractor shall not be required to excavate, remove, transport or otherwise dispose of:

(i) Pre-Existing Hazardous Material on the Job Site, other than as set forth in Section 3.16.1(d); and

(ii) Any waste, rubbish or Hazardous Material caused by FPL or its representatives.

3.10 OBTAINING, MAINTAINING AND IDENTIFYING PERMITS

3.10.1 Contractor shall, and shall cause its Subcontractors to comply with, all Applicable Permits, including FPL Permits and Contractor Permits. Contractor shall timely obtain and maintain all Contractor Permits. In addition, Contractor shall timely prepare and submit to the applicable Government Authority all engineering and construction related submittals, reports and other items (including those set forth in Appendix A, Scope of Work) required to maintain and comply with any FPL Permit and provide all assistance reasonably requested by FPL in connection with FPL's efforts to obtain the FPL Permits, including, without limitation, witnesses testimony, depositions, preparation and submission of exhibits, reports or submittals, technical calculations and attending meetings; provided that FPL shall provide Contractor, at no cost to FPL, with all information, documentation and assistance reasonably requested by Contractor to permit Contractor to comply with the provisions of this Section 3.10.1. In the event that any Applicable Permit is required for the Plant or to perform the Work that is not identified in the Contract Documents, Contractor or FPL, as applicable, shall promptly, after it becomes aware of the need for such Applicable Permit, notify the other Party that such Applicable Permit is required. If such permit is of a nature typically obtained by contractors in power projects, Contractor shall, at its sole cost and expense, be obligated to obtain and maintain such Applicable Permit on behalf of FPL. Otherwise, FPL shall obtain and maintain such Applicable Permit.

3.10.2 All Applicable Permits (other than any building permits (but excluding any applicable occupancy certificates) or other Applicable Permits designated as either "To be issued in the name of Contractor" or "To be issued in the name of FPL and Contractor" on Appendix A, Scope of Work, or Appendix M, FPL Permits) shall be issued in the name of FPL unless otherwise required by Applicable Law or such Applicable Permit. If any Contractor Permit (or application therefor) is in the name of FPL or otherwise requires action by FPL, FPL shall, upon the request of Contractor, sign such application or take such action as reasonably appropriate.

3.10.3 FPL reserves the right to review any such application of Contractor; provided, however, that FPL's exercise of such right shall not under any circumstances be considered an approval of the necessity, effect or contents of such application or related permit. Contractor shall deliver to FPL true and complete copies of all Applicable Permits obtained by Contractor upon its receipt thereof. Contractor shall use best efforts to identify in writing to FPL all Applicable Permits and other government requirements for performance of the Work not identified in the Contract Documents, or shall confirm in writing that, to the best of Contractor's knowledge, there are no such Applicable Permits or other government requirements other than as identified in the Contract Documents prior to the date of this Agreement.

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3.11 LABOR.

3.11.1 *General.* Contractor shall be responsible for retaining all Labor necessary for it to perform its obligations hereunder and comply with the provisions hereof, all in accordance with Applicable Laws. Contractor shall be responsible for all costs incurred in complying with this Section 3.11, or otherwise associated with its Labor, including, without limitation, costs incurred by any member of its Labor, whether by direct contract or subcontract, for medical treatment, transport and accommodation as a result of injuries or illness arising from engagement or employment in the execution of the Work.

3.11.2 *Engagement of Labor.* Contractor shall make its own arrangements for the engagement of all Labor in connection with the Contract Documents and the performance of the Work. Contractor shall employ in the performance of the Work only Labor, whether supervisors, skilled workers or laborers, who are competent to perform their assigned duties in a safe and secure manner and shall use all reasonable efforts to cause its Subcontractors and Vendors to adhere to the same standard with respect to their Labor. Contractor agrees, where required by Applicable Law, to employ only licensed personnel in good standing with their respective trades and licensing authorities to perform engineering, design, architectural and other professional services in the performance of the Work. All such professional services shall be performed with the degree of care, safety, skill and responsibility customary among such licensed personnel. All Labor shall have received formal documented training, to the extent required by Applicable Standards, in their area of expertise and, if applicable, certification.

3.11.3 *Identification.* Contractor shall identify each member of its and its Subcontractor's and Vendor's Labor in accordance with the standards and procedures that are mutually acceptable to the Parties.

3.11.4 *Supply of Services for Labor.* Contractor shall provide and maintain at the Job Site, in accordance with Applicable Laws and Applicable Permits, such accommodations, services and amenities as necessary for all Labor employed for the purpose of or in connection with the Contract Documents, including all water supply (both for drinking and other purposes), electricity supply, sanitation, safety, security, fire prevention and fire-fighting equipment, refuse disposal systems and other requirements in connection with such accommodations or amenities.

3.11.5 *Alcohol and Drugs.* Contractor shall not possess, consume, import, sell, give, barter or otherwise dispose of any alcoholic beverages or drugs (excluding drugs for proper medical purposes and then only in accordance with Applicable Law) at the Job Site, or permit or suffer any such possession, consumption, importation, sale, gift, barter or disposal by its Subcontractors, agents or Labor and shall at all times assure that the Job Site is kept free of all such substances. Contractor shall immediately identify and remove from its or its Subcontractors' employment at the Job Site any person (whether in the charge of Contractor or any Subcontractor) who is in possession of or under the influence of any dangerous or controlled drug, alcohol or other such substance at any time during such person's performance of any portion of the Work, excluding any person using a prescription drug under supervision and approval from a medical doctor, or any other person who does or whose actions may create any unsafe condition or other situation that may cause damage or harm to any person or property.

3.11.6 *Arms and Ammunition.* Except as required for Job Site security, Contractor shall not possess, give, barter or otherwise dispose of, to any person or persons, any arms or ammunition of any kind at the Job Site, or permit or suffer the same as aforesaid and shall at all times assure that the Job Site is kept free from arms and ammunition.

3.11.7 *Disorderly Conduct.* Contractor shall be responsible for the conduct and deeds of its Labor and its Subcontractors' Labor relating to the Contract Documents and the consequences thereof. Contractor shall at all times take all reasonable precautions to prevent any unlawful, riotous or disorderly conduct by or among such Labor and for the preservation of peace, protection and safety of Persons and property in the area of the Job Site against the same. Contractor shall not interfere with any members of any authorized police, military or security force in the execution of their duties.

3.11.8 *General Management of Employees.* Subject to FPL's rights as set forth in Section 3.11.11, Replacement at FPL's Request, Contractor shall preserve its rights to exercise and shall exercise its management rights in

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performing the Work. Such management rights shall include the rights to hire, discharge, promote and transfer employees; to select and remove foremen or other persons at other levels of supervision; to establish and enforce reasonable standards of production; to introduce, to the extent feasible, labor saving equipment and materials; to determine the number of craftsmen necessary to perform a task, job or project; and to establish, maintain and enforce rules and regulations conducive to efficient and productive operations.

3.11.9 *Labor Disputes*. Contractor shall use reasonable efforts to minimize the risk of labor-related delays or disruption of the progress of the Work. Contractor shall promptly take any and all reasonable steps that may be available in connection with the resolution of violations of collective bargaining agreements or labor jurisdictional disputes, including the filing of appropriate processes with any court or administrative agency having jurisdiction to settle, enjoin or award damages resulting from violations of collective bargaining agreements or labor jurisdictional disputes. Contractor shall advise FPL promptly, in writing, of any actual or threatened labor dispute of which Contractor has knowledge that might materially affect the performance of the Work by Contractor or by any of its Subcontractors or Vendors. Notwithstanding the foregoing, the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the discretion of the Party having the difficulty, except as expressly provided for in Section 14.1, Definition of Force Majeure Event.

3.11.10 *Personnel Documents*. Contractor shall ensure that all its personnel and personnel of any Subcontractors or Vendors performing the Work are, and at all times shall be, in possession of all such documents (including, without limitation, visas, driver's licenses and work permits) as may be required by any and all Applicable Laws.

3.11.11 *Replacement at FPL's Request*. Within one (1) day after request by FPL, Contractor shall remove from the Job Site and performance of the Work, and shall cause any Subcontractor or Vendor to remove from the Job Site and performance of the Work, any Person performing the Work whom FPL determines, in its sole discretion, to be creating a safety hazard or a material risk of either: (i) non-achievement of Mechanical Completion or Provisional Acceptance; or (ii) material non-performance by Contractor in accordance with this Agreement. In addition, Contractor shall include in each subcontract a provision that requires each Subcontractor and Vendor to remove any employee or independent contractor of such Subcontractor or Vendor used in the Work or in such Subcontractor's and Vendor's warranty obligations within one (1) day after receiving notice from FPL to remove such employee or independent contractor.

3.12 PROJECT MANAGEMENT AND CONTRACTOR'S REPRESENTATIVE.

3.12.1 *Project Management*. Contractor has designated a management team as set forth on Appendix O, Project Management Team, and any future members of the management team must be approved by FPL in writing prior to his/her designation, which approval shall not be unreasonably withheld. During the performance of the Work from the Initial Site Mobilization and thereafter, Contractor shall maintain continuously at the Job Site adequate management, supervisory, administrative, security and technical personnel, including the Contractor Site Manager, to ensure expeditious and competent handling of all matters related to the Work, according to its determination of the staffing required for this purpose. Contractor will not re-assign, remove or replace the Contractor Project Manager, Contractor Project Engineering Manager or Contractor Site Manager without FPL's prior written consent, which consent shall not be unreasonably withheld. Contractor shall promptly replace its Contractor Project Manager, Contractor Project Engineering Manager or Contractor Site Manager, upon written request of FPL, if such individual is disorderly or if in FPL's opinion, such individual is otherwise incompetent for his position and responsibilities.

3.12.2 *Contractor's Representative*. Contractor shall appoint one individual (the "Contractor's Representative"), with the prior written consent of FPL, which shall not be unreasonably withheld, who shall be authorized to act on behalf of Contractor and with whom FPL may consult at all reasonable times, and whose instructions, requests and decisions in writing will be binding upon Contractor. Contractor shall not remove or replace such representative without prior written notice to FPL.

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3.13 TEMPORARY OFFICE QUARTERS.

3.13.1 During the performance of the Work from the Initial Site Mobilization and thereafter, Contractor shall maintain, at a reasonable location designated by FPL, a suitable office at the Property Site at or near the site of the Work which shall be the headquarters of Contractor's Representative designated pursuant to Section 3.12, Project Management and Contractor's Representative, above.

3.13.2 Contractor shall provide FPL's representatives with office space, including all utilities, heating, ventilation and air conditioning, contemporaneously with the existence of Contractor's site office specified in paragraph (a) above, which office space shall be subject to the approval of FPL and be in compliance with the requirements therefore in Appendix A, SCOPE OF WORK. Contractor shall properly maintain such offices and shall employ sufficient personnel to clean such office each working day that such offices are used. Contractor shall be responsible for paying all utility deposits and charges, other than long distance telephone charges related to calls made by FPL and its representatives, related to such offices for FPL.

3.14 COOPERATION WITH OTHER CONTRACTORS/COMMUNITY.

3.14.1 Contractor acknowledges that work may be performed by others at the Job Site during the execution of Work under this Agreement. Contractor further acknowledges that FPL, through itself or through its employees, subcontractors or agents, will continue to work and perform activities in connection therewith at and around the Job Site during the execution of the Work under this Agreement. Contractor shall cooperate and cause its Subcontractors and Vendors to cooperate with FPL and other unrelated contractors who may be working at or near the Job Site in order to assure that neither Contractor, nor any of its Subcontractors or Vendors unreasonably hinders or increases, or makes more difficult than necessary the work being done by FPL and other unrelated contractors. Contractor agrees to perform the Work in full cooperation with such others and to permit, without charge, reasonable access to, and use of, the Job Site and the Work, by said others or by FPL, whether such Work is partially or entirely complete, when, in the judgment of FPL, such access or use is necessary for the performance and completion of the work of others. All material and labor shall be furnished, and the Work performed, at such time or times as shall be for the best interest of all contractors concerned, to the end that all Work, and the work of any separate contractor, will be properly coordinated and completed in accordance with the applicable schedules and the times of completion required by the Contract Documents.

3.14.2 In addition to complying with all Applicable Laws and Applicable Permits, Contractor shall use reasonable efforts, and cause its Subcontractors and Vendors to use their reasonable efforts, to assist FPL in creating, assessing and carrying out programs which shall, during all phases of the Work, minimize the impacts upon the host community caused by the construction of the Project. Such programs shall include: (i) sequencing of the Work so as to minimize the impacts of noise and dust at and around the Job Site; and (ii) using local labor and other resources whenever possible and cost effective.

3.15 PROTECTION AND SAFETY.

3.15.1 Prior to the Provisional Acceptance Date, Contractor shall be responsible for the security, protection and safety of all Persons (including members of the public and the employees, agents, contractors, consultants and representatives of FPL, the Financing Parties, Contractor and its Subcontractors and Vendors, and other contractors and subcontractors) and all public and private property (including structures, sewers and service facilities above and below ground, along, beneath, above, across or near the Job Site) that are at or near the Job Site or that are in any manner affected by the performance of the Work. As of the Provisional Acceptance Date, FPL shall have operational control over the Project. Notwithstanding the foregoing, Contractor shall remain responsible for the security, protection and safety of all Persons performing any portion of the Work at the direction of Contractor as well as any damage to property caused directly or indirectly by Contractor's negligent acts or omissions and/or failure to comply with the provisions of the Contract Documents while on the Job Site.

3.15.2 Contractor shall initiate and maintain reasonable safety precautions and accident prevention programs for the Job Site and in the performance of the Work, which shall be in compliance with all Applicable Laws and Applicable Permits, to prevent injury to persons or damage to property on, about or adjacent to the Job

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Site and in the performance of the Work. Without limiting the generality of the foregoing, Contractor shall furnish and maintain all necessary safety equipment such as barriers, signs, warning lights and guards as required to provide adequate protection to persons and property. In addition, Contractor shall give reasonable notice to owners of public and private property and utilities when such property is susceptible to injury or damage through the performance of the Work and shall make all necessary arrangements with such owners relative to the removal and replacement of protection of such property or utilities.

3.15.3 Contractor shall provide FPL with notice of Close Calls and Mishaps (as such terms are defined in the Lease) sufficient for FPL to comply with the requirements of Section 14.2 of the Lease. To the extent that Contractor is not required to provide FPL with notice pursuant to the first sentence of this Section 3.15.3, Contractor shall provide FPL, within five (5) Days following its occurrence, with written:

(a) Notification of all Occupational Safety and Health Act recordable events;

(b) Notifications and copies of all citations by Government Authorities concerning accidents or safety violations at the Job Site;

(c) Reports of near misses at the Job Site; and

(d) Copies of written accident reports for lost time accidents.

Contractor shall promptly deliver to FPL any written communication with any Government Authority or insurance company (including any notices) with respect to accidents that occur at the Job Site.

3.16 ENVIRONMENTAL MATTERS.

3.16.1 *Hazardous Material.* Contractor shall, and shall cause its Subcontractors and Vendors to, comply with all Applicable Laws relating to Hazardous Material and all Applicable Permits. Without limiting the generality of the foregoing:

(a) Contractor shall, and shall cause its Subcontractors and Vendors to, apply for, obtain, maintain and renew all Contractor Permits, and comply with all Applicable Permits, in any case, as required by Applicable Laws regarding Hazardous Material that are necessary, customary or advisable for the performance of the Work. Contractor shall, and shall cause its Subcontractors and Vendors to, have an independent Environmental Protection Agency identification number for disposal of Hazardous Material under the Contract Documents if and as required under Applicable Laws or Applicable Permits.

(b) Contractor shall conduct its activities under the Contract Documents, and shall cause each of its Subcontractors to conduct its activities, in a manner designed to prevent pollution of the environment or any other release of any Hazardous Material by Contractor and its Subcontractors and Vendors in a manner or at a level requiring remediation pursuant to any Applicable Law.

(c) Contractor shall not cause or allow the release or disposal of Hazardous Material at the Job Site, bring Hazardous Material to the Job Site, or transport Hazardous Material from the Job Site, except in accordance with Applicable Law and Applicable Permits. Contractor shall be responsible for the management of and proper disposal of all Hazardous Material brought onto or generated at the Job Site by it or its Subcontractors or Vendors, if any. Contractor shall cause all such Hazardous Material brought onto or generated at the Job Site by it or its Subcontractors or Vendors, if any, to be:

(i) Transported only by carriers maintaining valid permits and operating in compliance with such permits and laws regarding Hazardous Material pursuant to manifest and shipping documents identifying only Contractor as the generator of waste or person who arranged for waste disposal; and

(ii) Treated and disposed of only at treatment, storage and disposal facilities maintaining valid permits operating in compliance with such permits and laws regarding Hazardous

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Material, from which, to the best of Contractor's knowledge, there has been and will be no release of Hazardous Material.

(iii) Contractor shall submit to FPL a list of all Hazardous Material to be brought onto or generated at the Job Site prior to bringing or generating such Hazardous Material onto or at the Job Site. Contractor shall keep FPL informed as to the status of all Hazardous Material on the Job Site and disposal of all Hazardous Material from the Job Site.

(d) If Contractor or any of its Subcontractors or Vendors releases any Hazardous Material on, at, or from the Job Site, or becomes aware of any Person who has stored, released or disposed of Hazardous Material on, at, or from the Job Site during the Work, Contractor shall immediately notify FPL in writing. If Contractor's Work involved the area where such release occurred, Contractor shall immediately stop any Work affecting the area. Contractor shall, at its sole cost and expense, diligently proceed to take all necessary or desirable remedial action to clean up fully the contamination caused by any:

(i) Release by Contractor or any of its Subcontractors or Vendors of any Pre-Existing Hazardous Material; and

(ii) Hazardous Material that was brought onto or generated at the Job Site by Contractor or any of its Subcontractors or Vendors, whether on or off the Job Site.

(e) If Contractor discovers any Pre-Existing Hazardous Material that has been stored, released or disposed of at the Property Site, Contractor shall immediately notify FPL in writing. If Contractor's Work involves the area where such a discovery was made, Contractor shall immediately stop any Work affecting the area and FPL shall determine a reasonable course of action. Contractor shall not, and shall cause its Subcontractors and Vendors to not, take any action that may exacerbate any such contamination.

(f) Contractor shall be solely responsible for remedial action to clean up fully the contamination referenced in Section 3.16.1(d). If so requested by FPL, Contractor shall cooperate with and assist FPL in making the Job Site available for taking necessary remedial steps to clean up any such contamination at FPL's expense as determined in accordance with Section 6.3, CHANGES TO CONTRACT PRICE; DISPUTES, of Article VI, CHANGE ORDERS. Contractor shall promptly deliver to FPL any notice or violation, letter of non-compliance or similar communication from any Government Authority.

3.16.2 *Waste Treatment and Disposal.* Without limiting the foregoing:

(a) *Toxic Waste and Industrial Hazards:* Contractor shall be responsible for the proper management and disposal of all toxic waste and industrial hazards brought onto or generated at the Job Site by it or its Subcontractors or Vendors, if any. Contractor shall, and shall cause its Subcontractors and Vendors to, comply with all Applicable Laws, Applicable Permits and applicable safety standards related to the treatment, storage, disposal, transportation and handling of toxic wastes and industrial hazards. Contractor shall not store or dispose of toxic wastes and industrial hazards near groundwater, surface water or drainage systems. Liquid wastes shall not be dumped onto the ground or in any groundwater, surface water or drainage systems. All waste oil and grease resulting from construction activities shall be collected and disposed of in a manner that prevents contamination to soil, ground water, and surface water, and incinerated if possible. Vehicle maintenance shall be conducted in safe areas away from watercourses and oil or fluid runoff shall be collected in grease traps. Toxic waste and industrial hazard storage containers shall be well-labeled.

(b) *Sanitary and Solid Waste:* Contractor shall take appropriate measures in accordance with the Applicable Law and Applicable Permits for the treatment and disposal of sanitary and solid waste, and in particular, Contractor shall perform the Work in such a manner so as to protect environmentally sensitive areas and water supplies. Run-off from disposal sites shall be curtailed.

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3.16.3 *Fuel Storage*. The location, facilities, safety measures and environmental and pollution control in connection with storage of fuel or like substances shall comply with all Applicable Laws and Applicable Permits.

3.16.4 *Protected Areas*. Contractor acknowledges that portions of the Property Site may be wetlands or other protected areas ("Protected Areas") as indicated on the survey to be provided by FPL pursuant to Section 4.7, DESCRIPTION OF PROPERTY SITE, of Article IV, CERTAIN OBLIGATIONS OF FPL. Certain of these Protected Areas, if designated on such survey, do not constitute a part of the Job Site. Contractor shall erect a temporary barrier or other blockade to isolate Protected Areas and protect such areas from impact by any Work. Contractor shall not allow any Work to be conducted in or otherwise interfere with or impact such Protected Areas. Contractor shall, and shall cause its Subcontractors and Vendors to, comply with the Environmental Resource Plan and all permits, rules, regulations and all other Applicable Laws and Applicable Permits in connection with the Protected Areas on or adjacent to the Property Site.

3.17 FIRE PREVENTION.

3.17.1 Contractor shall be responsible for providing adequate fire prevention and protection at the Job Site and shall take all reasonable precautions to minimize the risk of fire at the Job Site. Contractor shall provide instruction to the Labor in fire prevention control and shall provide appropriate fire-fighting and fire protection equipment and systems at the Job Site.

3.17.2 Contractor shall promptly collect and remove combustible debris and waste material from the Job Site in accordance with Applicable Laws and Applicable Permits, and shall not permit such debris and material to accumulate. Contractor shall control the usage of fires for any purpose in the vicinity of the Work and shall agree upon the appropriateness of any such fires with FPL. Any areas of vegetation damaged by fire which are reasonably determined by FPL to have been initiated by Contractor's or Subcontractors' Labor shall be recultivated and otherwise rehabilitated by Contractor, at Contractor's expense.

3.17.3 Contractor will complete all systems, procedures and Equipment constituting the Plant fire protection system as necessary during construction to protect Work in progress, in particular with regard to fuel and other flammable materials.

3.18 RELIGIOUS AND ARCHAEOLOGICAL RESOURCES

In the event any archaeological or religious sites, places, monuments or areas are discovered or identified by Contractor during the performance of Work under the Contract Documents, Contractor shall leave such sites untouched and protected by fencing and shall immediately stop any Work affecting the area. Contractor shall notify FPL of any such discovery as soon as practicable, and Contractor shall carry out FPL's instructions for dealing with the same. All fossils, coins, articles of value or antiquity and structures and other remains or things of geological, archaeological, historical, religious, cultural or similar interest discovered on the Job Site shall, as between FPL and Contractor, be deemed to be the absolute property of FPL. Contractor shall prevent its and its Subcontractors' and Vendors' Labor and any other Persons from removing or damaging any such article or thing.

3.19 REPORTS, PLANS AND MANUALS.

3.19.1 *Status Reports*. Within ten (10) days after the beginning of each month, commencing with the month following the date of this Agreement, Contractor shall prepare and submit to FPL written progress reports, in accordance with the requirements of Appendix B, Project Schedule and Reporting Requirements, which include a description of the progress and status of the Work compared to the Project Schedule, the status of Equipment and other scheduled deliveries, the Subcontractors' activities and engineering, procurement and construction progress. In addition, each such progress report will provide cost information regarding backcharges and a summary of any Changes executed by the Parties as of the date of such report. A reasonable number of photographs shall also be included reasonably documenting the construction progress. Each photograph shall show the date, Contractor's name and description of the view taken. In accordance with Section 5.3, PROJECT SCHEDULE, of Article V, PROJECT SCHEDULE, Contractor shall also report any events which may affect the Project Schedule, including any Force Majeure Events, liens on the Property Site or the Project, or any asserted violations of Applicable Laws.

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3.19.2 *Reporting of Accidents*. Contractor shall report in writing to FPL (and, to the extent required by any Applicable Law or Applicable Permit, the appropriate Government Authority) details of any significant safety event or accident required to be reported under U.S. Department of Labor Occupational Safety & Health Administration standards that is on or about the Job Site as soon as possible after its occurrence, but in any event not later than forty-eight (48) hours after such accident occurs. In the case of any fatality or serious injury or accident, Contractor shall, in addition, notify FPL (and, to the extent required by any Applicable Law or Applicable Permit, the appropriate Government Authority) immediately.

3.19.3 *Procedures Manual*. No later than forty-five (45) days following the date hereof, Contractor shall prepare and submit to FPL a procedures manual that describes the administrative procedures to be used by Contractor and FPL for interfacing during the performance of the Work (the "Procedures Manual"). Contractor shall either promptly make changes to the Procedures Manual suggested by FPL or negotiate and resolve in good faith with FPL such changes. Upon approval of the Procedures Manual by the Parties, the Parties shall comply with the provisions thereof. The Procedures Manual may be changed from time to time with the approval of the Parties. Contractor shall provide six (6) copies, as well as an electronic copy, of the Procedures Manual to FPL.

3.19.4 *Health Plan, Safety Plan and Environmental Plan*. No later than thirty (30) days prior to Initial Site Mobilization, Contractor shall prepare and submit to FPL:

(a) A health plan that includes health, first aid facility/area with qualified attendant and emergency procedures to be used at the Job Site (the "Health Plan");

(b) An environmental plan (the "Environmental Plan" as more particularly described in Appendix A, Scope of Work) that includes:

(i) A Hazardous Material, waste and industrial hazards management and disposal program which details the controlled usage and treatment of all Hazardous Material, toxic wastes, industrial hazards, sanitary waste, solid waste and other waste brought onto, used or produced at the Job Site or in relation to the Work and outlines a management structure for carrying out the specific provisions of such program;

(ii) An environmental protection and management program, including, without limitation, a sediment and erosion control program

(iii) A revegetation program, with a Change Order related thereto; and

(iv) The description, location and drawings of construction facilities and temporary works; and

(c) A safety plan substantially in the form of Appendix Z, Form of Safety Plan, which shall include an acknowledgement by Contractor that Contractor shall at all times remain in compliance with all federal, state and local safety codes (the "Safety Plan").

Each of the Health Plan, Environmental Plan and Safety Plan shall be consistent with all Applicable Laws and Applicable Permits and shall be submitted to FPL for review and comment. Contractor shall either promptly make changes to such Health Plan, Environmental Plan or Safety Plan incorporating the comments of FPL or negotiate and resolve in good faith with FPL any such changes. Contractor shall comply and ensure that its Subcontractors comply with the Health Plan, Environmental Plan, Safety Plan, the Safe and Secure Workplace Policy, the Project Loss Manual and the Environmental Control Program.

3.19.5 *Meetings*. During the performance of the Scope of Work, Contractor and FPL shall, at a minimum, conduct meetings each month at a mutually convenient time and date for the purpose of reviewing the progress of the Scope of Work, the latest progress reports, the Health Plan, the Environmental Plan, the Safety Plan, Quality Assurance Program, Contractor's and Subcontractors' adherence to the Scope of Work and the Project Schedule as well as the status of any claims on the Project and claims submitted pursuant to the terms of the Contract Documents. Contractor shall prepare detailed minutes of each such meeting, in form and content acceptable to FPL, and shall distribute same to FPL within five (5) days after such meeting.

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3.19.6 *Contractor Not Relieved of Duties or Responsibilities.* Neither the submission to or approval by FPL of progress and other reports, plans and manuals, nor the provision of general descriptions shall relieve Contractor of any of its duties or responsibilities under the Contract Documents.

3.19.7 *Quality Assurance Program.*

(a) Contractor shall use effective quality assurance programs (collectively, the "Quality Assurance Program"), which such programs:

(i) Propose the manner in which Contractor intends to achieve the highest standards in the performance of the entire Scope of Work;

(ii) Shall be acceptable to FPL; and

(iii) Shall be consistent with the requirements of Appendix Y, Form of Quality Assurance Programs, and Appendix A, Scope of Work, in performing the Work.

(b) Within thirty (30) days after the date of this Agreement, Contractor shall provide to FPL a description of the Quality Assurance Program, which shall be substantially in the form of Appendix Y, Form of Quality Assurance Programs, (the "Quality Control Manual"), to be used by Contractor in the performance of the Work. The Quality Control Manual shall also include all proposed types of Critical Parameters that Contractor shall define as the Scope of Work progresses. "Critical Parameters" are defined as construction critical dimensions, commissioning critical set-points, critical alignments and process critical set-ups for Equipment, sub-systems, systems and the Plant, as mutually agreed to by the Parties.

(c) As soon as the Critical Parameters have been finalized, Contractor shall include the same in the Project Schedule. Contractor shall provide FPL with tentative dates for the performance of Critical Parameters, which dates shall be updated monthly, and shall also provide FPL with twenty-four (24) hour written notice prior to performance of any Critical Parameters. FPL will review and provide comments to such programs in writing within thirty (30) days after submission by Contractor.

(d) If FPL's comments are reasonable changes to the quality assurance programs submitted by Contractor, Contractor will effect such changes at no additional cost to FPL and resubmit such programs to FPL within ten (10) days after Contractor receives FPL's comments. FPL will have ten (10) days after such resubmission to review and provide comments to such programs resubmitted by Contractor. Such procedure shall continue with the same ten (10) day time periods until FPL accepts such programs. If FPL fails to respond within any of the applicable periods specified above, FPL shall be deemed to have agreed to the last such programs submitted by Contractor. If applicable, Contractor shall also submit verification of ISO 9001 qualification.

(e) Contractor's program shall address how improvement actions will be applied on the Project's processes, products and services. Contractor shall also have in place a formal system of collecting, reviewing and evaluating corrective and preventive actions from a lessons learned process that will ensure desirable changes regarding engineering, procurement, construction, start-up, turnover or operation feedback from recently completed (or in process projects) are incorporated.

(f) A post award (pre-production) meeting shall be held at Contractor's facility to demonstrate Contractor's understanding of the quality and quality assurance requirements, and present their methods of complying with these requirements.

3.20 DRAWINGS, ENGINEERING DATA AND OTHER MATERIALS.

3.20.1 All Drawings, Final Plans, reports and other information (except financial, accounting and payroll records) furnished to Contractor, or prepared by it, its Subcontractors or others in connection with the performance of the Work, whenever provided, shall be kept by Contractor in an orderly and catalogued fashion for reference by FPL during the performance by Contractor of the Work. Contractor shall maintain at the

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Property Site at least one (1) copy of all Drawings, Final Plans, Change Orders and other modifications in good order and marked to record all changes made during performance of the Work, including, without limitation, all field deviations from the construction drawings. As a condition precedent to Final Acceptance, or upon the earlier termination of this Agreement, Contractor shall transfer the Final Plans to FPL and they shall become the sole property of FPL.

3.20.2 Final Plans (in both hard copy and magnetic media at no extra charge to FPL), if not furnished earlier, shall be furnished to FPL upon Contractor's request for a Final Acceptance Certificate or upon the earlier termination of this Agreement. Contractor and any of its Subcontractors, as applicable, may retain copies all such documents for their records, subject to the confidentiality provisions of this Agreement.

3.20.3 No later than March 1, 2009, Contractor shall furnish FPL (in electronic format whenever available) with conceptual engineering drawings and the specifications pertaining to the electric generators and step-up transformers of the Plant, including demonstrations that the:

(a) Requirements for reactive supply facilities at the Plant will be met; and

(b) Plant will meet the guidelines and performance standards set forth in the Contract Documents and the Operating Guidelines.

3.20.4 Contractor shall submit all Drawings in electronic format to FPL in accordance with Appendix A, Scope of Work, for review and comment as provided in the Scope of Work. Based upon FPL's comments, if any, Contractor shall resolve FPL's comments. Contractor shall revise such Drawings from time to time, as required to reflect any changes, in the actual installation of any individual Equipment or system or the Plant as a whole. Notwithstanding anything contained herein to the contrary, FPL's review and/or acceptance of the Drawings, or any portion thereof, shall not in any way relieve Contractor of any of its obligations or warranties set forth herein, including, but not limited to, its full responsibility for the accuracy of the dimensions, details, integrity and quality of the Drawings.

3.21 OPERATING AND MAINTENANCE MANUALS

Contractor shall supply FPL with manuals and/or handbooks (in electronic format) which provide, either in a single manual or handbook or collectively, complete operating and maintenance instructions (including inventories of spare parts and tools and parts lists with ordering instructions) for each major piece of Equipment and system of the Plant. Each such manual and handbook shall comply with the requirements of the Scope of Work and the guidelines contained in Appendix L, including with respect to matters such as quantity, content and the time when such manuals are to be supplied to FPL, and shall be substantially complete and delivered to FPL prior to Mechanical Completion in order to support training of personnel and start-up and testing of the Plant.

3.22 TRAINING OF O&M PERSONNEL.

3.22.1 During the construction of the Plant, and at least ninety (90) days prior to the Provisional Acceptance Date, Contractor shall provide, at its own expense, a training program in Plant operation and maintenance for FPL's Plant personnel and the O&M Contractor's Plant personnel (collectively, "O&M Personnel"). The training program provided by Contractor shall be subject to FPL's prior written approval and shall:

(a) Include classroom and field training;

(b) Include all manuals, drawings, and other educational materials necessary or desirable for the adequate training of O&M Personnel; and

(c) Establish quality controls so that O&M Personnel are suitably trained and capable of operating and maintaining the Plant after Provisional Acceptance.

Representatives of manufacturers of Equipment shall be utilized to provide specialized training for such Equipment where deemed necessary by the Parties. All training programs conducted in accordance with this Section 3.22, shall be videotaped and made available to FPL in electronic format.

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3.22.2 Contractor shall make every reasonable effort to use the O&M Personnel during Plant start-up and initial operation; however, neither FPL nor O&M Contractor shall be obligated to:

(a) Supply personnel for the construction of the Plant; nor

(b) Provide during Plant start-up and initial operation more O&M Personnel than the number of O&M Personnel FPL and O&M Contractor would use during normal Plant operation as determined by FPL. Contractor shall have complete responsibility for directing, coordinating, monitoring and supervising O&M Personnel during Plant start-up and initial Plant operations.

3.22.3 In addition, Contractor shall:

(a) Remain solely responsible for performing the Work in accordance with this Agreement, including Contractor's obligation to achieve Mechanical Completion, achieve Provisional Acceptance by the Guaranteed Provisional Acceptance Date and achieve Final Acceptance, regardless of any act, omission, failure, non-achievement, or non-performance of the O&M Personnel;

(b) Remain fully responsible for all acts and omissions of the O&M Personnel in connection with the commissioning and operation of the Plant until the Provisional Acceptance Date as fully as if Contractor had independently engaged such O&M Personnel; and

(c) Be responsible for all acts and omissions of the O&M Personnel after the Provisional Acceptance Date if such acts or omissions are taken at the direction of Contractor.

3.22.4 The cost of the O&M Personnel's travel, lodging, food and other living expenses shall be borne by FPL. Contractor shall have the right to require FPL to remove O&M Personnel from the Job Site if Contractor reasonably believes that any such O&M Personnel is unable to properly perform its obligations in connection with the commissioning and operation of the Plant and Contractor provides FPL a written explanation of its reasons for exercising the removal rights granted to it hereunder; provided that the failure of such O&M Personnel to perform their obligations or the removal of any O&M Personnel pursuant to this Section 3.22, shall not relieve Contractor of any of its obligations hereunder.

3.23 ACCOUNTING INFORMATION; FINANCIAL REPORTING REQUIREMENTS

3.23.1 During the term of this Agreement and continuing for five (5) years after the Final Acceptance Date, Contractor will provide FPL with any reasonably necessary assistance, including providing all documents, cost information and other information that FPL believes necessary, in a form reasonably acceptable to FPL, for FPL's federal, state or local tax filings, exemptions or positions advocated by FPL, including, without limitation, sales, use and property taxes; provided, however, that such access to cost information not otherwise made available to FPL pursuant to the terms hereof shall be disclosed to an independent auditor of FPL's choice that agrees to keep secret from FPL, Contractor's cost and other competitively sensitive information.

3.23.2 Unless otherwise publicly available, Contractor shall as soon as available, but in any event within sixty (60) days after each of the first three (3) quarters of each calendar year, deliver to FPL a copy of the complete unaudited balance sheet for such quarter for the Contractor Parent Company prepared in accordance with generally accepted accounting principles and certified by the Chief Financial Officer of Contractor Parent Company. Unless otherwise publicly available, Contractor shall as soon as available, but in any event within ninety (90) days after December 31 of each year, deliver to FPL a copy of the complete audited financial statements for such year with an unqualified opinion for the Contractor Parent Company prepared in accordance with generally accepted accounting principles.

3.24 CONTRACTOR TAXES.

3.24.1 Except for FPL Taxes, Contractor shall, as required by applicable law, pay and administer any and all Taxes and duties incurred or payable in connection with the Work, including, without limitation, taxes based on or related to the income, receipts, capital or net worth of Contractor, Contractor's or its Subcontractors' or Vendors' Labor or income, except for FPL Taxes (collectively, "Contractor Taxes"); provided, however, that if Contractor is responsible for payment of FPL Taxes under Applicable Law,

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unless otherwise instructed by FPL or FPL is contesting such FPL Taxes, Contractor shall pay such FPL Taxes and any penalties and interest due thereon, and FPL shall reimburse Contractor for such FPL Taxes and any penalties and interest due thereon resulting from instructions provided by FPL upon submission of evidence of payment. Contractor shall promptly provide FPL with reports or other evidence reasonably acceptable to FPL showing the payment of Contractor Taxes by Contractor and any FPL Taxes required to be paid by Contractor pursuant to this Section 3.24. Contractor shall use commercially reasonable efforts to cooperate with FPL to endeavor to minimize any FPL Taxes. Notwithstanding the foregoing, Contractor agrees to purchase for resale to FPL any machinery or equipment in connection with the Work that would be the type of property that would qualify as manufacturing machinery and equipment entitled to the exemption from the Florida sales and use tax provided under Applicable Laws and, at the direction of FPL, Contractor agrees to take such action as may be reasonably required to allow such property, to the extent possible to qualify for any sales or use tax exemption. If required in connection with the purchase of any such property from its Vendors, to the extent permitted by applicable law, Contractor agrees to provide its Vendors a resale certificate or applicable affidavit as approved by the State of Florida reflecting the fact that Contractor is purchasing such property for resale to FPL. Contractor agrees to take any other action reasonably necessary to ensure that the purchase of qualifying machinery with respect to the Work is exempt from sales and use tax under Florida (or other applicable) law. To the extent Contractor is required by Applicable Law to collect sales tax from FPL, Contractor shall collect sales tax from FPL on all materials physically incorporated in the Plant that are not subject to exemption unless FPL has elected to provide Contractor with a direct pay certificate issued to FPL by the State of Florida, in which case, FPL shall pay such sales tax directly to the State of Florida. In the event that an assessment for sales and/or use or excise taxes are levied against Contractor, any Subcontractor or Vendor, Contractor shall promptly notify FPL and furnish to FPL a copy of such assessment. In the event that FPL determines that the assessment should be contested and so notifies Contractor in writing, FPL may, at FPL's sole cost and expense, file such documents as are necessary to contest such assessment. FPL shall exclusively control any contest, assessment or other action regarding any such taxes or assessments, or any penalties or interest in respect thereof. In addition to Contractor's other obligations as set forth herein, Contractor shall cooperate with and assist FPL, at FPL's expense, in any contest or proceeding relating to Taxes payable by FPL hereunder.

3.24.2 Exempt Equipment. Some of the machinery, equipment, parts or other items of tangible personal property to be incorporated into the Plant may be exempt from certain taxes (such exempt items, the "Exempt Equipment"). FPL and Contractor will work together to determine which purchases constitute purchases of Exempt Equipment, and Contractor and FPL will take reasonably necessary actions to ensure that such Exempt Equipment qualifies for applicable tax exemptions.

3.25 CLAIMS AND LIENS FOR LABOR AND MATERIALS

If FPL is paying when due all undisputed amounts in accordance with the Contract Documents, Contractor shall, at Contractor's sole expense, discharge and cause to be released, whether by payment or posting of an appropriate surety bond in accordance with Applicable Law, within ten (10) days after receipt of a written demand from FPL, any Lien in respect to the Plant, the Contract Documents, the Equipment, the Job Site or any fixtures or personal property included in the Work (whether or not any such Lien is valid or enforceable) created by, through or under, or as a result of any act or omission (or alleged act or omission) of, Contractor or any Subcontractor, Vendor or other Person providing labor or materials within the scope of Contractor's Work. Notwithstanding the foregoing provision, as long as FPL, in its sole discretion, determines that the Job Site and the improvements thereon will not be subject to any liability, penalty or forfeiture, upon the written request of Contractor, FPL may permit Contractor to contest the validity, enforceability or applicability of any such Lien, in which event FPL shall provide, at no cost to FPL, such cooperation as Contractor may reasonably request in connection therewith.

3.26 SPARE PARTS AVAILABILITY.

3.26.1 *Start-up Spare Parts*. Prior to Mechanical Completion, Contractor shall obtain all spare parts required for Plant start-up and testing. All spare parts not used during Plant start-up and testing shall become the

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property of FPL, it being understood and agreed that additional photovoltaic panels held by Contractor at the Project Site but not incorporated into the Project shall not be deemed to be spare parts.

3.26.2 *Operating Spare Parts*. At least ten (10) days prior to the Provisional Acceptance Date, Contractor shall provide FPL with each manufacturer's recommended spare parts list for the Equipment, which list shall include part numbers, recommended quantities, price, mean times to failure, mean times to repair and a description of lead times necessary for orders of such spare parts, in each case to the extent reasonably available to Contractor. Contractor agrees to:

(a) Obtain from each Major Manufacturer an assignable guaranty that such Major Manufacturer will have available for purchase by FPL for a period of five (5) years after the Provisional Acceptance Date, all spare parts for the Major Equipment supplied by such Major Manufacturer required to keep the Plant in good operating condition, it being understood that some of such parts are not "shelf items" and will have to be manufactured by the Major Manufacturer after it receives an order for them;

(b) Make spare parts (other than spare parts for the Major Equipment) available for purchase by FPL for a period of five (5) years after the Provisional Acceptance Date to the extent that Contractor is able to obtain them from the manufacturer who supplied them for the Plant as originally built;

(c) Find another source that can supply such spare parts if Contractor is unable to obtain such spare parts from such manufacturer; and

(d) Obtain a firm price for such spare parts reasonably acceptable to FPL for a period of five (5) years after the Provisional Acceptance Date.

3.26.3 With regard to the spare parts described in paragraph (b) above, upon written notice from FPL at any time prior to the Provisional Acceptance Date, Contractor shall, at FPL's expense but without mark-up or multiplier, purchase and have delivered to the Job Site as soon as possible permanent plant spares. Contractor will pay for and replace such spares if used during start-up and commissioning of the Plant.

3.27 CONTRACTOR'S OBLIGATION TO NOTIFY

Contractor shall keep FPL advised as to the status of the Equipment and Work and shall promptly inform FPL in writing upon the occurrence of any of the following, any:

3.27.1 Occurrence or event that may be expected to impact the schedule for delivery and/or installation of Equipment;

3.27.2 Technical problem not anticipated at the start of the Work or of significant magnitude that may impact the Plant or any component thereof or the Project Schedule;

3.27.3 Defect; and

3.27.4 Material changes to previously submitted information. FPL shall have the right to verify the information provided by Contractor. In connection therewith, Contractor shall identify those items provided to FPL that would enable FPL to verify such information in an expedient manner.

3.28 CONSTRUCTION UTILITIES

Contractor shall be responsible for the cost, supply and availability of electric power and distribution requirements for the performance of the Work at the Job Site for the construction and up to Provisional Acceptance; provided, however, Contractor shall be responsible for the cost of any such items to the extent required in order to reperform any Tests. Contractor shall provide its own telephone, facsimile, radio and other communication facilities at the Job Site as necessary for the performance of the Work. If FPL determines that any Test performed or to be performed by Contractor will result in financial harm to FPL, Contractor will accommodate FPL's reasonable requests to mitigate or alleviate such harm to FPL. In addition, Contractor shall provide, at its sole cost and expense, all chemicals for commissioning, start-up and testing and its own temporary lighting, water and sewer facilities at the Job Site.

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3.29 LINES AND GRADES

Contractor shall provide for the proper laying out of the construction Work, for making measurements and for establishing temporary or permanent reference marks in connection with the construction Work and Plant. Contractor shall ensure that all improvements constructed in connection with the Work are constructed within the boundaries of the Property Site as delineated in Appendix P, Legal Description of Property Site, and do not encroach on any easements, rights of way or other improvements existing on the Property Site as delineated in Appendix P, Legal Description of Property Site. FPL may at its sole discretion and cost, check the reference marks, lines, grades and measurements so established. Contractor shall carefully preserve all monuments, bench marks and reference points. In case of its destruction thereof, Contractor will be responsible for all damages, costs and expenses related to their replacement and for any mistake or loss of time that may result therefrom. Permanent monuments or bench marks which must be removed or disturbed shall be protected until they can be properly referenced for relocation. Contractor shall furnish materials and assistance for the proper replacement of such monuments or bench marks.

3.30 TEMPORARY STRUCTURES

Temporary structures for offices, quarters, storage and other uses for Contractor, its Subcontractors and Vendors and FPL shall be constructed only in locations approved by FPL. Contractor shall erect temporary walls, bulkheads or fences where required to isolate the construction area from adjacent property in order to increase safety and security and to minimize noise, dust and dirt from affecting the property surrounding the Job Site.

3.31 WEATHERPROOF COVERINGS

Contractor shall provide adequate and sufficient weatherproof and flame resistant coverings for outdoor storage at the Job Site. The cover or sheeting shall be tied down to prevent moisture from damaging the Equipment.

3.32 INTELLECTUAL PROPERTY RIGHTS.

3.32.1 Contractor agrees to grant and hereby grants to FPL an irrevocable, permanent, non-exclusive, royalty-free license to utilize all of Contractor's trade secrets, patents, copyrights, trademarks, proprietary rights or information, licenses and other intellectual property rights (collectively, the "Intellectual Property Rights") and the Intellectual Property Rights of third parties (to the extent of Contractor's rights thereto which can be transferred without violation of obligations owed to such third parties), to the extent now existing or developed primarily for the Project, related to the Work, to the extent reasonably necessary for completion, design, construction, installation, operation, maintenance, repair, or replacement of the Project, or Contractor's expansion, modification, or alteration of the Project (or any subsystem or component thereof designed, specified, or constructed by Contractor under this Agreement).

3.32.2 FPL shall have the right to assign the benefit of such license to any Financing Party in connection with granting a security interest in the Project or any portion thereof, to a purchaser in connection with a transfer of the Project, or to any subsequent purchaser or assignee of same. Any such purchaser or assignee shall acquire such license subject to the same terms and restrictions as stated in this Section 3.32.

3.32.3 Contractor shall, prior to directing any Subcontractor to produce any design or engineering work in connection with the Project, obtain a valid written assignment of all applicable Intellectual Property Rights from such Subcontractor in terms identical to those that obligate Contractor to FPL as expressed in this Section 3.32, which Intellectual Property Rights Contractor hereby assigns to FPL.

3.32.4 Should Contractor or any employee or agent of Contractor make any invention or discovery in connection with performing the Work, such invention or discovery shall be deemed to be the sole and exclusive property of Contractor. To the extent FPL has any right or title thereto or interest therein, FPL hereby assigns (and shall cause the assignment of) all such right and title to, and interest in, any such invention or discovery to Contractor. FPL shall, at Contractor's expense and request, cooperate in pursuing and effecting the transfer to Contractor of all of FPL's right and title to and interest in any such invention or discovery, including, without limitation, executing or causing the execution of assignments and applications, and assign with prosecution and enforcement of rights with respect to any such invention or

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discovery, including, without limitation, executing patent applications and powers of attorney with respect thereto. Notwithstanding the above, in the event FPL contributes to the joint invention of any invention or discovery in connection with the Project ("FPL Assisted Discoveries"), Contractor hereby grants (and shall grant) to FPL a non-exclusive, royalty-free license to use such FPL Assisted Discoveries for any purpose at any location in the State of Florida.

3.32.5 This Section 3.32, shall survive the expiration or termination of this Agreement.

3.33 EMERGENCIES

In the event of any emergency that endangers or could endanger life or property, Contractor shall take such action as may be reasonable and necessary to prevent, avoid or mitigate injury, damage or loss and shall, as soon as possible, report any such incidents, including Contractor's response and actions with respect thereto, to FPL.

3.34 [INTENTIONALLY DELETED]

3.35 WASTEWATER, POTABLE WATER

Contractor shall supply at its expense all raw, potable and other water at the Job Site as necessary in connection with the installation, start-up and testing of the Plant. Contractor shall dispose of all wastewater in conformance with Applicable Law and Applicable Permits.

3.36 [INTENTIONALLY DELETED]

3.37 START UP PROCESS

Contractor shall perform the Plant start-up in accordance with the process set forth in Appendix A, Scope of Work. Whenever FPL's staffing situation permits, FPL and Contractor shall mutually agree upon and utilize qualified FPL seconded personnel for start-up leadership positions, including the technical start-up manager and key start-up supervision positions; provided, however, Contractor shall remain fully responsible for all acts and omissions of such personnel in connection with the commissioning and operation of the Plant until the Provisional Acceptance Date as if Contractor had independently engaged such personnel, and be responsible for all acts and omissions of such personnel after the Provisional Acceptance Date if such acts or omissions are taken at the direction of Contractor.

3.38 ACCOMMODATIONS REGARDING TESTING

Contractor shall (excluding any action which will affect Contractor's ability to complete the Work within the time required pursuant to this Agreement or increase Contractor's cost to complete the Work) coordinate with FPL the scheduling of any Test, which efforts may include modification of Contractor's planned test program to maximize the value of energy sold. Contractor shall coordinate such Test with the dispatch schedule for the Plant, so as not to interfere with FPL's or its Affiliates' obligations with respect thereto.

3.39 ACCESS; COMPLIANCE WITH LEASE

Contractor shall use only the entrance(s) to the Job Site specified by FPL for ingress and egress of all personnel, equipment, vehicles, and materials. Contractor shall perform the Work consistent and in accordance with FPL's leasehold, license and easement rights in and to the Job Site. Contractor has reviewed the Lease and confirms that the rights granted to FPL therein are sufficient for Contractor to perform its Work hereunder. Contractor shall comply with the terms of the Lease, including but not limited to all restrictions applicable to FPL and/or its contractors respecting permitted use, access, landowner entry, impacts to the Property Site, environmental plans and compliance, insurance, security and accidents, all as more particularly described in the Lease.

3.40 NATURE OF OBLIGATIONS

Except as expressly stated to the contrary herein, the Contract Price includes the cost of completion of all the foregoing obligations. Contractor hereby agrees that it shall be ultimately responsible for the performance of all activities, which may be necessary and desirable for the full performance of the Scope of Work, all in accordance with the Contract Documents.

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ARTICLE IV.
CERTAIN OBLIGATIONS OF FPL

4.1 PERMITS

FPL shall, with Contractor's reasonable assistance (to be provided at no cost to FPL), timely obtain and maintain, at its own cost and expense, all FPL Permits. In addition, FPL shall execute such applications as Contractor may reasonably request in connection with obtaining any of the Contractor Permits; provided, that FPL shall provide Contractor with such information and documentation, at no cost to FPL, as Contractor shall reasonably request in order to execute such applications. FPL shall deliver to Contractor evidence that the FPL Permits necessary to begin construction of the Plant have been received by FPL or, if any such required FPL Permit has not actually been issued, that it has been approved for issuance, or in the opinion of FPL, will be approved for issuance.

4.2 INTERCONNECTION FACILITIES

At least thirty (30) days prior to the Provisional Acceptance Date, FPL shall give Contractor reasonable access to the FPL Interconnection Facilities.

4.3 FPL OBLIGATIONS IN SCOPE OF WORK

FPL shall comply with each and every obligation and duty assigned to FPL in the Scope of Work.

4.4 [INTENTIONALLY DELETED]

4.5 ACCESS TO PROPERTY SITE

Subject to the Lease (including but not limited to the restrictions contained in Section 4.2 of the Lease) and Section 3.37, START UP PROCESS, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, and consistent with the terms of the Applicable Permits and FPL's leasehold, license, and easement rights in and to the Job Site, FPL shall make the Job Site reasonably available to Contractor and its Subcontractors and Vendors and assure reasonable rights of ingress and egress to and from the Job Site for Contractor and its Subcontractors and Vendors for performance of the Work; provided, however, that Contractor shall coordinate with FPL regarding: (i) initial entry onto the Job Site or any part thereof; and (ii) contact with the Persons who own property on or near, or have granted license or easement rights in and to, the Job Site. During the period commencing on the Final Acceptance Date and ending at the expiration of the Warranty Period provided in Section 12.1.4(c), FPL shall make the Job Site reasonably available to Contractor for the sole purpose of monitoring FPL's compliance with operation and maintenance manuals and manufacturers' guidelines applicable to the Equipment in connection with Contractor's satisfaction of its warranty obligations under Article 12, Contractor's Warranties.

4.6 [INTENTIONALLY DELETED]

4.7 DESCRIPTION OF PROPERTY SITE

On or before thirty (30) days after the date of the Agreement, FPL shall deliver to Contractor a boundary survey of the Property Site. Contractor may rely on such boundary survey for the sole purpose of establishing the boundaries of the Property Site.

4.8 NOTICE OF FINANCIAL CLOSING

FPL shall give Contractor prompt written notice of the scheduled and actual date of Financial Closing.

4.9 FPL TAXES

FPL shall pay all real property taxes assessed against the Property Site and any permanent use charges (but excluding charges and taxes for utilities and fuel to be supplied by Contractor as required hereunder, which shall be Contractor's responsibility), and, subject to Section 3.24, CONTRACTOR TAXES, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR FPL, shall be responsible for the payment of, or reimbursement to Contractor of, state or local sales and/or use taxes assessed by the State of Florida (or any city, county or municipality therein) in connection with the purchase of all Equipment,

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except for such taxes FPL contests in good faith, in each case including any such taxes resulting from a Change In Law (collectively, "FPL Taxes"). In the event that FPL is required to pay additional Taxes, penalties or interest because Contractor failed to follow written instructions of FPL appropriately or to comply with its obligations under Section 3.24, CONTRACTOR TAXES, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR FPL, Contractor shall be responsible for the cost of such additional Taxes, penalties or interest within thirty (30) days of FPL's request therefor.

4.10 FPL'S COOPERATION

At no additional cost to FPL, FPL shall make reasonable efforts to supply to Contractor, in a timely manner, either directly or indirectly, material information and data that is available to FPL and that is required for the performance of the Work; provided, however, FPL does not warrant the correctness of the information and documentation provided hereunder. Although FPL may provide or may have provided Contractor with copies of certain studies, reports or other information (including oral statements), Contractor acknowledges and agrees that:

4.10.1 All such documents or information have been or will be provided as background information and as an accommodation to Contractor;

4.10.2 FPL makes no representations or warranties with respect to the accuracy of such documents or the information (including oral statements) or opinions therein contained or expressed; and

4.10.3 It is not relying on FPL for any information, data, inferences, conclusions, or other information with respect to the Job Site (other than the boundary survey referred to in Section 4.7, DESCRIPTION OF PROPERTY SITE), including the surface and subsurface conditions of the Job Site and the surrounding areas.

4.11 FPL'S REPRESENTATIVE

No later than the date of this Agreement, FPL shall designate in writing one or more representatives at the Property Site (at least one of whom shall be at the Job Site during normal business hours) who shall act as the point of contact for both Contractor and the Independent Engineer with respect to the prosecution of the Work, administration of the Contract Documents on behalf of FPL, approval of Contractor's submissions hereunder and inspection of the Work, as reasonably necessary for Contractor's performance of the Work; provided that such representative(s) shall not be authorized to execute or make any amendments to, authorize Change Orders in respect of, or provide waivers under, this Agreement. FPL shall provide Contractor with prior written notice in the event that it designates any additional representatives or removes any existing representatives.

4.12 [INTENTIONALLY DELETED]

4.13 OPERATION AND MAINTENANCE

Subject to Contractor's removal rights set forth in Section 3.22, TRAINING OF O&M PERSONNEL, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, FPL shall, commencing fifteen (15) days prior to the anticipated Provisional Acceptance Date (as determined by FPL based on the circumstances existing at the time of determination), provide O&M Personnel with skills and training appropriate for the operation of a photovoltaic solar power plant reasonably required for training by Contractor as provided in accordance with Section 3.22, TRAINING OF O&M PERSONNEL, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, and for testing, start-up, operation, commissioning, and maintenance of the Project; provided, however, that Contractor shall remain solely responsible for performing the Work in accordance with this Agreement, including Contractor's obligation to achieve Mechanical Completion and Provisional Acceptance on or before the Guaranteed Provisional Acceptance Date, regardless of any act, omission, failure, non-achievement, negligence or non-performance of such O&M Personnel.

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ARTICLE V.
PROJECT SCHEDULE

5.1 [INTENTIONALLY DELETED]

5.2 NOTICE TO PROCEED

5.2.1 *Commencement Date.* Between two to eight (2-8) weeks before Contractor will construct improvements at, or deliver materials to, the Job Site that may be insured pursuant to a Builder's Risk Policy, Contractor shall deliver in writing to FPL a notice setting forth the Commencement Date.

5.2.2 *[Intentionally Deleted]*

5.2.3 *[Intentionally Deleted]*

5.2.4 *Notice to Proceed.* The Business Day after which FPL provides Contractor with the Notice to Proceed shall be the "Notice to Proceed Date"; provided, however, that the Notice to Proceed Date shall not be later than March 1, 2009 (the "Latest Notice to Proceed Date"). On the Notice to Proceed Date, Contractor shall commence and shall thereafter diligently pursue all of the Work assigning to it a priority that should reasonably permit the attainment of Provisional Acceptance on or before the Guaranteed Provisional Acceptance Date. Contractor shall proceed with the performance of the Work in accordance with the Project Schedule.

5.2.5 *Delay in Notice to Proceed.* If a Notice to Proceed has not been issued by the Latest Notice to Proceed Date, and such failure causes an increase in the Contract Price or time required for performance of the Work, then Contractor shall promptly notify FPL thereof in writing and FPL may either (i) issue a Change Order to address such failure in which event the Latest Notice to Proceed Date shall be extended for thirty (30) days and the procedure set forth herein shall be repeated upon the expiration of each additional thirty (30) day period; or (ii) terminate this Agreement pursuant to Section 15.3,and FPL shall only be obligated to pay Contractor an amount equal to any applicable Termination Payment. If this Agreement is terminated pursuant to this Section 5.2.5, then except as set forth in Section 15.3, neither Party shall have any further rights or obligations hereunder (other than such rights and obligations that by the express terms of this Agreement survive the expiration or earlier termination of this Agreement).

5.3 PROJECT SCHEDULE.

5.3.1 Contractor shall perform the Work in compliance with the Project Schedule, including completing the Work required by the Guaranteed Provisional Acceptance Date and the Final Acceptance Date. Contractor hereby covenants and warrants to FPL that in undertaking to complete the Work in accordance with the terms hereof, Contractor has taken into consideration and made reasonable allowances for hindrances and delays incident to such Work not caused by FPL. Contractor shall provide the reports as required herein, and provide any further information required by FPL as FPL, the Financing Parties or the Independent Engineer may reasonably request to verify actual progress and forecast future progress of the Work. Contractor shall promptly notify FPL in writing of any occurrence that Contractor has reason to believe will adversely affect the completion of the Work by the Guaranteed Provisional Acceptance Date or materially adversely affect completion of the Work in accordance with the Project Schedule. Contractor will specify in said notice the corrective action planned by Contractor to overcome the effect of the delay or potential delay.

5.3.2 Without limiting the obligations of Contractor under Section 5.3.1, above, Contractor shall provide, together with its monthly status reports required hereunder, a project schedule and any updates thereto that provide for the orderly, practicable and expeditious completion of the Work in accordance with the requirements of the Contract Documents. The project schedule and any update shall be presented electronically on a monthly basis and in such reasonable detail as FPL and the Independent Engineer may require and shall address all material elements of the Work. Additionally, the updated project schedule shall be made available to FPL monthly, and as otherwise reasonably requested by FPL, in MS Project format on a computer located at the Property Site. Contractor shall consult with FPL in connection with each update provided under this paragraph. Notwithstanding anything contained herein to the contrary, in

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the absence of a Change Order, no update to the project schedule shall in any way amend, alter or otherwise change the Project Schedule or the Guaranteed Provisional Acceptance Date.

5.3.3 *Adequate Assurance*. In the event FPL reasonably believes Contractor's completion of any Critical Milestone set forth in Appendix C, Critical Milestones and Milestones, will not be completed by the date required therein, FPL shall notify Contractor in writing, and Contractor shall, within seven (7) days of receipt of FPL's notice, provide to FPL a written plan detailing the activities or sequence of events Contractor will implement to assure completion of the Critical Milestone by the date required in Appendix C, Critical Milestones and Milestones, and Contractor shall promptly implement such activities and sequence of events. In the event Contractor fails to complete any of the Critical Milestones by the date required in Appendix C, Critical Milestones and Milestones, Contractor shall provide to FPL a written recovery plan that will demonstrate achievement of the Critical Milestone at the earliest possible date to minimize delay of the Project Schedule and Contractor shall promptly implement any such recovery plan. Such recovery plan shall include, without limitation, reasonable evidence of increases in Contractor's work force, increases in the number of shifts, overtime operations, additional days of Work per week, and such other evidence (including Critical Path schedule analysis) as necessary for the timely completion of the Work in accordance with the Contract Documents. Approval by FPL and the Independent Engineer of such plan shall not:

(a) Be deemed in any way to have relieved Contractor of its obligations under this Agreement relating to the failure to achieve Mechanical Completion or Provisional Acceptance by the Guaranteed Provisional Acceptance Date;

(b) Be a basis for an increase in the Contract Price; or

(c) Limit the rights of FPL under Section 11.2, SCHEDULE LIQUIDATED DAMAGES, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

Further, Contractor acknowledges that the implementation of any such recovery plan may result in material additional costs and expenditures for Contractor (including by way of overtime, additional crews and/or additional shifts). Contractor agrees that it shall not be entitled to a Change Order or any other compensation or increase in the Contract Price in connection with the implementation of any such recovery plan.

5.3.4 No later than fifteen (15) days following the date hereof, Contractor shall prepare and submit to FPL for review and comment a preliminary draft of the Critical Path, in form and content acceptable to FPL. Upon receipt of comment from FPL, Contractor shall either promptly make changes to the Critical Path as suggested by FPL or negotiate and resolve in good faith with FPL such changes. Upon approval of the Critical Path by the Parties, Contractor shall comply with the provisions thereof. Contractor shall provide five (5) copies, as well as an electronic copy, of the Critical Path to FPL. Contractor shall not revise or modify the Critical Path, except pursuant to a Scope Change Order mutually agreed by the Parties.

5.3.5 In no event will Contractor's failure to complete one or more Milestones by the date required for such Milestone change, delay or otherwise affect the required completion date for any other Milestone.

5.4 ACCELERATION OF WORK

In addition to the provisions of Sections 5.3.3, above, relating to delays in the Work, in the event of delay, including any event which causes the prosecution of the Work to fail to conform to the Project Schedule, FPL may, by notice to Contractor, direct that the Work be accelerated by means of overtime, additional crews or additional shifts or resequencing of the Work. If:

(a) Such delay arises from any FPL Caused Delay or Force Majeure Event; or

(b) Contractor provides reasonable evidence to FPL that such delay results from a suspension pursuant to Section 15.4, SUSPENSION BY FPL FOR CONVENIENCE, of Article XV, TERMINATION.

then Contractor shall be entitled to reimbursement of increased cost as a result of such acceleration (i.e., premium portion of overtime pay, additional crew, shift or Equipment cost and such other items of incremental cost requested in advance by Contractor and approved by FPL which approval will not be unreasonably withheld) less savings or costs not incurred due to such acceleration, but expressly waives any other compensation therefor. CONTRACTOR SHALL RECEIVE NO SUCH REIMBURSEMENT FOR COSTS ARISING OUT OF, AND CONTRACTOR SHALL BE SOLELY RESPONSIBLE FOR ANY COSTS INCURRED BY CONTRACTOR AS A RESULT OF, ACCELERATION RELATED TO ANY EVENT OTHER THAN THE EVENTS SPECIFICALLY DESCRIBED IN THIS SECTION 5.4, PARAGRAPHS (a) AND (b), ABOVE. Contractor shall cause prosecution of the Work to conform to the Project Schedule within thirty (30) days after receiving written notice from FPL to accelerate the Work.

5.5 LIQUIDATED DAMAGES

Nothing contained in this Article shall relieve Contractor of its obligation to pay Schedule Liquidated Damages in the event that Provisional Acceptance is not achieved by the Guaranteed Provisional Acceptance Date.

ARTICLE VI.
CHANGE ORDERS

6.1 CHANGE ORDER AT FPL'S REQUEST.

6.1.1 FPL may at any time, by written notice to Contractor, request an addition to or deletion from or other changes in the Work or schedule therefor (together with any necessary or requested amendments to this Agreement with respect thereto) (hereinafter "Change" or "Changes") by submitting a Request for Change Order in the form attached hereto as Appendix S, Form of Request for Change Order. Contractor shall review and consider such requested Change and shall make a written response thereto within ten (10) days after receiving such request. If Contractor believes that giving effect to any Change requested by FPL will increase or decrease its cost of performing the Work, shorten or lengthen the time needed for completion of the Work, require modification of its warranties in Article XII, CONTRACTOR'S WARRANTIES, or require a modification of any other provisions of the Contract Documents, its response to the Change request shall set forth such changes (including any amendments to the Contract Documents) that Contractor deems necessary as a result of the requested Change and its justification therefor. If Contractor accepts the Changes requested by FPL (together with any amendments to the Contract Documents specified therein) or if the Parties agree upon a modification of such requested Changes, the Parties shall set forth the agreed upon Change in the Work and agreed upon amendments to the Contract Documents, if any, in a written change order signed by all Parties (a "Change Order"). Each Change Order shall constitute a final settlement of all items covered therein, including any compensation for impact on, or delay or acceleration in, performing the Work. If the Parties do not agree upon all terms of the Change Order, Contractor shall proceed with such Work and the dispute shall be resolved in accordance with Article XVII, DISPUTE RESOLUTION; provided that if the Parties are unable to reach agreement on the cost of a requested Change, Contractor shall perform the requested Change in accordance with Section 6.3, CHANGES TO CONTRACT PRICE, below.

6.1.2 FPL may at any time, by written notice to Contractor, propose Changes in the Work or the Project Schedule due to a Force Majeure Event or an FPL Caused Delay. If there is a material impact that will actually, demonstrably, adversely and materially affect Contractor's ability to complete one or more Critical Milestones by the required date as a result of such Force Majeure Event or an FPL Caused Delay, then the Parties agree to bargain reasonably and in good-faith for the execution of a mutually acceptable Change Order. Force Majeure Events will only entitle Contractor to extensions of the Project Schedule.

6.2 CHANGE ORDERS REQUESTED BY CONTRACTOR.

6.2.1 It is the intent of FPL and Contractor that the Scope of Work attached hereto as Appendix A, Scope of Work, includes all items necessary for the proper execution and completion of the Work. As more particularly described in Section 3.1.3, Contractor's Exclusions, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR work not described in the Scope of Work attached hereto

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as Appendix A, Scope of Work, shall not require a Change Order if such work is consistent with and reasonably inferable from the Scope of Work, so that an engineering, procurement and construction contractor of Contractor's experience and expertise should have anticipated that the work would have been required.

6.2.2 Subject to Section 6.2.3, below, Contractor may at any time, by written notice to FPL, request a Change in the Work (together with any necessary or requested amendments to the Contract Documents) and FPL may accept or reject such request in its sole discretion. If Contractor believes that such requested Change will increase or decrease its cost of performing the Work, lengthen or shorten the time needed for completion of the Work, require modification of its warranties in Article XII, CONTRACTOR'S WARRANTIES, or require a modification of any other provisions of the Contract Documents, it shall notify FPL of such, setting forth its justification for and effect of such changes, within ten (10) days after making a request for a Change. If FPL accepts the Changes requested by Contractor (together with amendments to the Contract Documents specified therein, if any), or if the Parties agree upon a modification of such requested Changes, the Parties shall set forth the agreed upon Change in the Work and agreed upon amendments to the Contract Documents, if any, in a written Change Order signed by all Parties. For the avoidance of doubt, the Parties agree that FPL's representative referred to in Section 4.11 shall not have authority to approve Change Orders. The Parties acknowledge and agree that one or more of the documents and agreements, including agreements with Subcontractors, may not be amended orally or through course of conduct. The Parties hereby express their intention that this Agreement will not be modified orally, through course of conduct or otherwise (regardless of whether any other agreements or documents relating to this Project have been so amended or modified).

6.2.3 Contractor may at any time, by written notice to FPL, propose Changes in the Work or the Critical Milestones due to:

(a) A Force Majeure Event, provided that such Force Majeure Event has an impact that will actually, demonstrably, adversely and materially affect Contractor's ability to complete one or more Critical Milestones by the required dates and further provided that Contractor complies with requirements provided in Article XIV, FORCE MAJEURE EVENT AND FPL CAUSED DELAY, and Section 6.2.2, above;

(b) An FPL Caused Delay, provided that such FPL Caused Delay has a demonstrable material cost increase to Contractor and/or schedule impact that will actually, demonstrably, adversely and materially affect Contractor's ability to complete one or more Critical Milestones by the required dates and further provided that Contractor complies with the requirements set forth in Article XIV, FORCE MAJEURE EVENT AND FPL CAUSED DELAY;

(c) A Change In Law, provided that such Change In Law prevents Contractor from performing all or a portion of the Work, has a demonstrable material cost increase to Contractor and/or has a schedule impact that will actually, demonstrably, adversely and materially affect Contractor's ability to complete one or more Critical Milestones by the required dates, and further provided that Contractor shall diligently make adjustments to minimize the effect of such Change In Law on the Project; or

(d) Certain unforeseeable subsurface conditions but only to the extent provided in Section 3.4.4, Differing Condition, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR.

Unless the foregoing conditions are met, Contractor may not request a Change in the Work or Critical Milestones due to a Force Majeure Event, FPL Caused Delay, Change In Law or unforeseeable subsurface conditions.

6.2.4 If FPL agrees that Contractor has met all of the applicable conditions precedent for a requested Change, then the Parties agree to bargain reasonably and in good faith for the execution of a mutually acceptable Change Order. Force Majeure Events will only entitle Contractor to extensions of the Project Schedule. If in such event the Parties are unable to agree on a mutually acceptable Change Order, then the dispute shall

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be resolved in accordance with Article XVII, DISPUTE RESOLUTION. Any extension permitted under this Section shall be of an equitable duration designed to reflect the delay actually caused by the relevant event despite Contractor's reasonable efforts to mitigate the same.

6.2.5 Intentionally Deleted.

6.2.6 If Contractor knows of circumstances or events that do or may require a Change in the Work or Project Schedule, and Contractor does not provide written notification to FPL of such within fifteen (15) days after the date Contractor knows or should have known (in the exercise of due diligence) of such circumstances or events, then Contractor shall not have any right to request or require any additional consideration or other changes as to cost, schedule, warranty obligations or other provisions hereof, and Contractor shall have waived any claims or offsets against FPL, with respect to any Change Order or any necessary Change in the Work or Project Schedule arising out of such circumstances or events.

6.3 CHANGES TO CONTRACT PRICE; DISPUTES

A Change Order initiated by either Party may have the effect of either increasing or decreasing the Contract Price. Any Contractor response to a Change Order under Section 6.1, CHANGE ORDER AT FPL'S REQUEST, above, and any Contractor request for Changes under Section 6.2, CHANGE ORDERS REQUESTED BY CONTRACTOR, above, shall be accompanied by a proposed all inclusive final lump sum cost (separating materials and labor) to FPL. In the event that the Parties are unable to reach an agreement on an all-inclusive final lump sum cost to FPL or a not-to-exceed cost as a result of a requested Change, then Contractor agrees to perform the requested Change and the Contract Price shall be adjusted by the amount of such additional cost and expense as is not in dispute pending resolution of the dispute pursuant to Article XVII, DISPUTE RESOLUTION. In addition, in the event that FPL and Contractor are unable to reach agreement on a Change Order for a Change requested by either FPL or Contractor, at the direction of FPL (and only at the direction of FPL), FPL's proposed Changes shall become effective as a Change Order and Contractor shall continue to perform the Work in accordance with such Change Order and the proposed Changes shall be performed by Contractor at its sole cost and expense pending resolution of the dispute pursuant to Article XVII, DISPUTE RESOLUTION.

6.4 INFORMATION REQUESTS

FPL may request that Contractor provide written information (prior to the issuance of a request for Changes) regarding the effect of a contemplated Change on pricing, scheduling, warranty obligations or on other terms of the Contract Documents. The purpose of such a request will be to determine whether or not a Change will be implemented. Contractor shall provide the requested information within fourteen (14) days after the receipt of said request. Contractor will be allowed to reasonably delay its response to such request to the extent that fulfilling such request would significantly delay progress on the Work, unless FPL agrees to extend the required completion date for the affected Milestone. Such an information request is not a Change Order and does not authorize Contractor to commence performance of the contemplated change in Scope of Work.

6.5 MINOR CHANGES

FPL shall have the direct authority to issue clarifications and order minor changes in the Work, effected by written order, which do not involve any adjustment to the Contract Price or the Guaranteed Provisional Acceptance Date and do not require Contractor to incur any additional material cost or expense; provided that such clarifications and changes are consistent with the intent of the Contract Documents. Such clarifications and changes shall be binding on FPL and Contractor. Contractor shall carry out such written orders promptly and Contractor shall receive no additional compensation therefor, nor shall there be any change to the Contract Documents.

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7.3 GENERAL PROVISIONS FOR PAYMENTS.

7.3.1 If applicable, any payment by FPL shall be accompanied by a notice to Contractor specifying the amount of each deduction and setting forth the reason(s) why the deduction is justified; provided that FPL's failure to provide any such notice shall not result in a breach hereof or be deemed a waiver of any right to deduct any amount hereunder. NOTWITHSTANDING ANY PROVISION OF THIS AGREEMENT TO THE CONTRARY, FAILURE BY FPL TO PAY ANY AMOUNT DISPUTED IN GOOD FAITH UNTIL RESOLUTION OF SUCH DISPUTE IN ACCORDANCE WITH THIS AGREEMENT SHALL NOT ALLEVIATE, DIMINISH, OR MODIFY IN ANY RESPECT CONTRACTOR'S OBLIGATIONS TO PERFORM HEREUNDER, INCLUDING CONTRACTOR'S OBLIGATION TO MEET THE GUARANTEED PROVISIONAL ACCEPTANCE DATE.

7.3.2 Failure or forbearance on the part of FPL in withholding any amounts due under a Request for Payment or invoice shall not be construed as accepting or acquiescing to any disputed claims. In addition, the making of any payment by FPL shall not constitute an admission by it that the Work covered by such payment (or any Work previously performed) is satisfactory or timely performed, and FPL shall have the same right to challenge the satisfactoriness and timeliness of such Work as if it had not made such payment. If, after any such payment has been made, it is subsequently determined by FPL, acting reasonably, that Contractor was not entitled to all or a portion of any such payment, Contractor shall promptly refund all or a portion of such payment to FPL.

7.3.3 *Protect FPL From Loss*. Notwithstanding any other provision to the contrary contained herein, FPL, in addition to its rights set forth in Section 7.5, LETTERS OF CREDIT, shall have no obligation to make payments to Contractor hereunder and FPL may decide not to certify payment or may nullify the whole or a part of a certification for payment made pursuant to a previous Request for Payment to such extent as may be necessary in FPL's opinion to protect FPL from loss because of:

(a) Defective Work not remedied;

(b) Third party claims filed (including Liens), or reasonable evidence indicating probable filing of such claims;

(c) Failure of Contractor to make payments when due to Subcontractors or Vendors;

(d) Damage to FPL or another contractor, including damage to the property of FPL or any of its Affiliates but only to the extent Contractor may be liable for such damage pursuant to this Agreement;

(e) Contractor's, or any Subcontractor's or Vendor's failure to carry out the Scope of Work in accordance with the Contract Documents;

(f) The occurrence of a Contractor Event of Default;

(g) A good faith determination by FPL that Contractor cannot, with prompt and reasonable acceleration of the Work, achieve Provisional Acceptance before the Guaranteed Provisional Acceptance Date; provided, however, the amount withheld or retained on account of this paragraph, shall not exceed the amount of Schedule Liquidated Damages which would be payable under Section 11.2, SCHEDULE LIQUIDATED DAMAGES, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, on account of the then estimated delay in Provisional Acceptance;

(h) Contractor's failure to deliver a recovery plan acceptable to FPL as set forth in:

(i) Section 5.3.3, Adequate Assurance, of Article V, PROJECT SCHEDULE, or

(ii) the failure of Contractor to cause the prosecution of the Work to conform to any such recovery plan accepted by FPL;

(i) Contractor's failure to deliver any Contractor Deliverable to FPL on or before the date such item is scheduled to be delivered; or

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(j) Contractor's failure to remove and replace, or cause any Subcontractor or Vendor to remove and replace, within ten (10) days after receiving notice pursuant to Section 3.11.11, Replacement at FPL's Request, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, any employee of Contractor or such Subcontractor or Vendor who is employed in the Work or the warranty obligations of Contractor or such Subcontractor or Vendor.

Notwithstanding the provisions of Section 15.7, TERMINATION BY CONTRACTOR DUE TO FPL DEFAULT, of Article XV, TERMINATION, and 17.3, CONTINUING OBLIGATIONS AND RIGHTS, of Article XVII, DISPUTE RESOLUTION, Contractor shall not have any rights of termination or suspension under such Sections as a result of FPL's exercise or attempted exercise of its rights under this Section 7.3. FPL shall release payments withheld pursuant to this Section 7.3.3 within thirty (30) days from the date when Contractor cures all such breaches to the satisfaction of FPL.

7.3.4 Each payment made pursuant to this Article shall be paid directly to Contractor. Such payment shall be wire-transferred to an account or accounts designated by Contractor in its Request for Payment.

7.4 INTENTIONALLY DELETED.

7.5 LETTERS OF CREDIT

No later than March 1, 2009, Contractor shall, at its own expense, cause the LC Issuing Bank to issue and maintain, by renewal or replacement, for the periods specified herein, an irrevocable, unconditional, transferable, standby, revolving letter of credit in favor of FPL meeting the requirements of this Section 7.5, and in form and substance as set forth on Appendix U, Form of Letter of Credit, (the "Letter of Credit") and such Letter of Credit must provide for draws in the United States. The Letter of Credit shall constitute security for Contractor's obligations hereunder. All fees and charges, including, without limitation, issuing, commitment and operation fees and charges, relating to the Letter of Credit shall be borne by Contractor. The Letter of Credit shall comply with and be subject to the following terms and conditions:

7.5.1 Upon issuance, the Letter of Credit shall have a face amount equal to One Million One Hundred and Forty-Five Thousand Six Hundred and 00/100 Dollars ($1,145,600.00). On July 1, 2009, the face amount shall automatically be increased to (or the LC Issuing Bank may issue a replacement Letter of Credit with a face amount equal to) Two Million Eight Hundred and Sixty Four Thousand and 00/100 Dollars ($2,864,000.00); provided, if Contractor elects to cause the LC Issuing Bank to issue a replacement Letter of Credit to FPL, upon receipt of such replacement Letter of Credit by FPL, FPL shall, as promptly as practicable thereafter, mark the replaced Letter of Credit "canceled" and return it to the LC Issuing Bank for cancellation .On the date (the "Initial LC Amount Expiration Date") sixty (60) days after either Contractor satisfies the Energy Yield Test or the Contract Price is reduced, in each case, in accordance with Section 11.4.3,, and thereafter so long as the Letter of Credit is required to be provided hereunder, the face amount shall automatically be reduced to (or the LC Issuing Bank may issue a replacement Letter of Credit with a face amount equal to) One Million Four Hundred and Thirty-Two Thousand and 00/100 Dollars ($1,432,000.00); provided, if Contractor elects to cause the LC Issuing Bank to issue a replacement Letter of Credit to FPL, upon receipt of such replacement Letter of Credit by FPL, FPL shall, as promptly as practicable thereafter, mark the replaced Letter of Credit "canceled" and return it to the LC Issuing Bank for cancellation. Within seven (7) Days of FPL's notice to Contractor of the occurrence of a Credit Trigger Event, either (a) the face amount of the Letter of Credit shall be adjusted in accordance with paragraph 2 of Appendix E – Credit Trigger Event or (b) Contractor shall post additional collateral in a form acceptable to FPL, including cash, which combined with the then-existing Letter of Credit, shall equal the adjusted face amount then-applicable in accordance with paragraph 2 of Appendix E – Credit Trigger Event. Thirty (30) days after the later of (a) the second anniversary of the Final Acceptance Date and (b) the date that Contractor has satisfied all warranty obligations related to breaches of warranty for which Contractor was notified prior to the second anniversary of the Final Acceptance Date (such later date, the "Letter of Credit Expiration Date"), FPL shall return the Letter of Credit to the LC Issuing Bank with instructions for cancellation.

7.5.2 FPL shall have the right to draw upon the Letter of Credit by presenting to the LC Issuing Bank a draw certificate pursuant to the Letter of Credit attached hereto as Appendix U, Form of Letter of Credit. FPL

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ARTICLE VIII.
TITLE, RISK OF LOSS AND POSSESSION

8.1 CLEAR TITLE

8.1.1 Contractor warrants and guarantees that legal title to and the ownership of the Work (including, without limitation, all Equipment, patents, licenses, Contractor Deliverables, operation and maintenance manuals and any spare parts purchased by Contractor on behalf of FPL at FPL's request in connection with the construction, operation and maintenance of the Plant) shall pass to FPL, free and clear of any and all Liens, upon Provisional Acceptance.

8.1.2 Notwithstanding anything to the contrary, the costs of unloading and transporting to the Job Site are included in the Contract Price.

8.2 RISK OF LOSS

8.2.1 From the date hereof until the Provisional Acceptance Date, Contractor hereby assumes the risk of loss for the Project and the Work, including:

(a) Any Equipment whether on or off the Job Site;

(b) All other Work completed on or off the Job Site; and

(c) All Work in progress.

8.2.2 All Equipment not yet incorporated into the Plant shall be stored in secured areas. Contractor shall bear the responsibility of preserving, safeguarding, and maintaining such Equipment and any other completed Work and Work in progress (including spare parts provided by FPL). If any loss, damage, theft or destruction occurs to the Work, on or off the Job Site, for which Contractor has so assumed the risk of loss, Contractor shall, at FPL's option and at Contractor's cost, promptly repair or replace the property affected thereby. If FPL elects not to repair or replace the affected property, Contractor shall pay to FPL any proceeds received from the insurance required to be maintained by Contractor pursuant to Section 9.1.8 due to such loss, damage, theft or destruction. Risk of loss for the Project and the Work shall pass to FPL (excluding Contractor Equipment and other items to be removed by Contractor, which shall remain the responsibility of Contractor) on the Provisional Acceptance Date. Subject to the foregoing, from and after the date of the transfer of risk of loss, FPL shall assume all risk of physical loss or damage thereto; provided, however, Contractor shall, subject to the provisions of Article XII, Contractor's Warranties, continue to be responsible after Provisional Acceptance Date for claims, physical loss or damage to the Work to the extent resulting from (a) the acts or omissions of Contractor or any Affiliate thereof, any Subcontractor or Vendor, or anyone directly or indirectly employed by any of them, or anyone for whose acts such Person may be liable and/or (b) any failure to comply with the requirements of the Contract Documents.

ARTICLE IX.
INSURANCE

9.1 CONTRACTOR INSURANCE POLICIES

Upon execution of the Agreement and continuing through the Final Acceptance Date, Contractor shall, at its sole cost and expense, obtain and maintain and cause its Subcontractors to obtain and maintain in force insurance policies satisfying the requirements of this Article, providing the following coverages of the types and in the amounts as follows (the "Contractor Insurance Policies"):

9.1.1 *Workers' Compensation Insurance*. Workers' Compensation that complies with the laws of the State of Florida and such other jurisdictions as may be applicable to its operations and includes an alternate employer endorsement. The amount of coverage of the insurance policy shall be the statutory amount required by the laws of the State of Florida. Where applicable, coverage shall include protection under the U.S. Longshoreman's and Harbor Worker's Act, Outer Continental Shelf Lands Act and Maritime Law, including the Jones Act and Death on the High Seas Act. Contractor expressly agrees to comply with all

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provisions of the Workers' Compensation Laws or similar employee benefit laws of the United States, or wherein said Work is to be performed, or of the countries from which its personnel are employed, where required, if applicable.

9.1.2 *Employers' Liability Insurance*. Employers' Liability Insurance including Occupational Disease in the amount of One Million Dollars ($1,000,000).

9.1.3 *Comprehensive or Commercial General Liability Insurance*. Comprehensive or Commercial General Liability insurance shall be on a broad form occurrence basis which shall be in the amount of Two Million Dollars ($2,000,000) per occurrence and Two Million Dollars ($2,000,000) in the aggregate for this Project including, but not limited to coverage for the following:

(a) Premises and Construction Operations;

(b) Independent Contractors;

(c) Products and Completed Operations, maintained for a period of two (2) years from the Final Acceptance Date;

(d) Explosion, Collapse and Underground Hazards;

(e) Broad Form Contractual Liability Coverage, applicable to damages and indemnities set forth in this Agreement;

(f) Personal Injury Coverage;

(g) Non-Owned Watercraft, if applicable;

(h) Broad Form Property Damage;

(i) Cross Liability coverage or Severability of Interest clause;

(j) Broad Form Named Insured Endorsement; and

(k) Action over coverage.

9.1.4 *Automobile Liability Insurance*. Automobile Liability Insurance, on an occurrence basis including coverage for all owned, leased, hired or non-owned automotive equipment (and containing appropriate no fault insurance provisions or other endorsements as are required under jurisdictional law or requirements), in the amount of One Million Dollars ($1,000,000) per occurrence or the amount required by Applicable Law, whichever is greater.

9.1.5 *Umbrella Excess Liability Insurance*. Umbrella Excess Liability to be provided on a following form basis with coverage as broad as the primary policies in the amount of Twenty Million Dollars ($20,000,000) each occurrence and in the aggregate.

9.1.6 *All Risk Equipment Insurance*. All Risk Equipment Insurance covering all risk of physical damage to equipment owned by Contractor and/or provided for use at the Job Site by Contractor.

9.1.7 *Professional Liability Insurance*. Professional Liability Insurance on a claims made basis with limits of $1,000,000 each occurrence and, at execution of this Agreement, $2,000,000, and upon the Commencement Date, $3,000,000, aggregate for liability arising out of any negligent act, error, mistake or omission resulting from Contractor's engineering, procurement, construction, design, commissioning, start-up and testing services, such coverage to remain in effect for not less than four (4) years following Provisional Acceptance.

9.1.8 *Inland and Marine Cargo Insurance*. Inland and Marine Cargo Insurance, if applicable - replacement value, which coverage may be included as part of the Builder's Risk Policy.

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9.2 FORM OF CONTRACTOR INSURANCE POLICIES.

9.2.1 Each Contractor Insurance Policy shall be written on an occurrence basis. Subject to the limits and coverages specified in Section 9.1, CONTRACTOR INSURANCE POLICIES, and except for Workers' Compensation, Contractor shall name FPL, designated Affiliates of FPL, the Utility, the Financing Parties and any other Person designated by FPL (including their respective officers, directors and employees) as additional insureds on Contractor's liability policies as required to be carried by Contractor by the provisions of Section 9.1, CONTRACTOR INSURANCE POLICIES, for liabilities of Contractor under the Contract Documents. Each Contractor Insurance Policy shall provide, either in its printed text or by endorsement, that:

(a) It shall be primary with respect to the interest of FPL, designated Affiliates of FPL and the Financing Parties (including their respective officers, directors and employees); and

(b) Any other insurance maintained by FPL, designated Affiliates of FPL or the Financing Parties is in excess and not contributory to Contractor Insurance Policies in all instances regardless of any like insurance coverage that FPL, designated Affiliates of FPL and the Financing Parties may have.

9.2.2 Contractor shall require the issuers of the coverages specified in 9.1, CONTRACTOR INSURANCE POLICIES, to amend such Contractor Insurance Policies to:

(a) Include a waiver of all rights of subrogation against the Financing Parties, FPL and designated Affiliates of FPL and any other Person designated by FPL and their respective directors, officers and employees;

(b) Contain a severability of interest provision;

(c) Provide that none of the Financing Parties, FPL or designated Affiliates of FPL or their respective directors, officers or employees shall be liable for the payment of premiums under such policy;

(d) Provide that complete copies of all inspection or other reports required or performed for the insurer shall be provided to both FPL and the Financing Parties within thirty (30) days of delivery to Contractor;

(e) Provide that FPL and the Financing Parties must be given at least sixty (60) days' prior written notice of any change in, non-renewal or cancellation of such coverages that are initiated by insurer, except ten (10) days for non-payment of premium, and

(f) Provide that FPL and the Financing Parties must be given at least sixty (60) days' prior written notice of any change in, non-renewal or cancellation of such coverages that are initiated by Contractor, except ten (10) days for non-payment of premium.

9.2.3 Contractor shall be responsible for additional costs associated with modifying inadequate coverage, terms and conditions to meet the requirements of this Agreement. Contractor shall comply with all the conditions stipulated in each of the insurance policies. Contractor shall make no material alteration to the terms of any insurance required herein without the prior written approval of FPL. If an insurer makes (or purports to make) any such alteration, Contractor shall notify FPL immediately. If any such notice is sent from an office outside the United States, it will be sent by international courier. Contractor shall be responsible to insure against risk of loss or damage to any Contractor Equipment and other equipment and tools that will not be incorporated into or become part of the Project.

9.3 QUALIFIED INSURERS

All Contractor Insurance Policies shall be written by insurers reasonably acceptable to FPL and the Financing Parties and that are rated "A-" or higher by A.M. Best's Key Rating Guide, or as may be approved in writing by FPL and the Financing Parties from time to time (a "Qualified Insurer"). In addition, if required by the Financing Parties, the Qualified Insurer must be able to provide a non-vitiation endorsement.

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9.4 CERTIFICATES OF INSURANCE

Contractor shall require all insurers under Contractor Insurance Policies to provide the Financing Parties, FPL and such other interested Persons as may be designated by FPL with certificates of insurance, in form and substance acceptable to the Financing Parties and FPL, evidencing and describing the insurance policies and endorsements maintained hereunder prior to commencement of the Work, or upon issuance of such policies, if earlier, and on each issuance anniversary while such insurance is in effect. The certificates of insurance shall evidence and describe the insurance policies and endorsements, including, without limitation, the requirements for the additional insured and waiver of subrogation as described in Section 9.2, FORM OF CONTRACTOR INSURANCE POLICIES. Notwithstanding anything to the contrary contained herein, evidence of such coverage shall be provided to FPL as a condition precedent to Initial Site Mobilization.

9.5 INSPECTION OF CONTRACTOR INSURANCE POLICIES

In respect of all Contractor Insurance Policies, Contractor shall, when so requested by FPL, produce Contractor's policies of insurance and confirmation of premium payment for such policies. If policies have not been secured on a project specific basis, Contractor may delete proprietary information not relevant to Contractor/FPL project prior to transmission.

9.6 SUBCONTRACTORS' INSURANCE

Before permitting any of its Subcontractors to perform any Work at the Job Site, Contractor shall obtain a certificate of insurance from each such Subcontractor evidencing that such Subcontractor has obtained the insurance required of Subcontractors by Contractor and in the case of Substantial Subcontractors, as required by FPL. All policies of Substantial Subcontractors shall include, and Contractor shall use reasonable efforts to require all other Subcontractors to include, a waiver of any right of subrogation of the insurers thereunder against FPL, the Financing Parties and Contractor, and any right of the insurers to set-off or counterclaim, offset or any other deduction, whether by attachment or otherwise, in respect of any liability or any such Person insured under such policy. Policies provided by Substantial Subcontractors and Substantial Vendors shall be in amounts and upon conditions as are customarily and normally provided in the major, grid-connected solar power generation industry.

9.7 REMEDY ON FAILURE TO INSURE

If Contractor shall fail to obtain and keep in force Contractor Insurance Policies, FPL may, without limiting any other remedy it may have, obtain and keep in force any such insurance and pay such premium or premiums as may be necessary for that purpose and recover from Contractor whether by way of deduction, offset or otherwise the cost of obtaining and maintaining such insurance.

9.8 MANAGEMENT OF INSURANCE POLICIES

Except as directed by FPL, Contractor shall be responsible for managing and administering all Contractor Insurance Policies, including the payment of all deductibles and self-insured retention amounts, the filing of all claims and the taking of all necessary and proper steps to collect any proceeds on behalf of the relevant insured Person. Contractor shall at all times keep FPL informed of the filing and progress of any claim. If Contractor shall fail to perform these responsibilities, FPL may take such action as it determines appropriate under the circumstances. In the event Contractor collects proceeds on behalf of other Persons, it shall ensure that these are paid directly from the insurers to the relevant Person and, in the event that it receives any such proceeds, it shall, unless otherwise directed by FPL, pay such proceed to such Party forthwith and prior thereto, hold the same in trust for the recipient.

9.9 FPL INSURANCE POLICIES

Subject to Section 9.9.3, prior to the Initial Site Mobilization by Contractor and continuing through the Final Acceptance Date, FPL shall obtain and maintain in force with responsible and reputable insurance carriers, subject to usual and customary terms, exclusions and limitations and deductible provisions the following insurance of the types set forth below:

9.9.1 *Workers' Compensation Insurance*. Workers' Compensation covering all of FPL's employees - statutory limit;

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9.9.2 *Employers' Liability Insurance*. Employers' Liability covering all of FPL's employees;

9.9.3 *Property Insurance*. After Provisional Acceptance and through the end of all of the Warranty Periods, FPL shall provide property insurance for the Plant and the Property Site in an amount and on terms that FPL deems reasonable.

9.9.4 *All Risk Installation and Builder's Risk Insurance*. No later than the Commencement Date, FPL shall obtain and maintain in force an All Risk Installation and Builder's Risk Insurance Policy (the "Builder's Risk Policy"). The Builder's Risk Policy shall be in an amount at least equal to the maximum foreseeable loss that could reasonably be sustained with respect to the Project or, if such amount is unavailable, such lower amount as may be commercially available at the time FPL procures such policy. A certificate of insurance evidencing the Builder's Risk Policy shall be furnished to the Contractor within thirty days after Contractor notifies FPL in writing that it will construct improvements at, or deliver materials to, the Job Site that may be insured pursuant to a builder's risk policy. Contractor shall be named as an additional insured on any Project-specific Builder's Risk Policy. The Builder's Risk Policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines, provided the per occurrence deductible shall not exceed the amounts which are available to FPL on a commercially reasonable basis, as determined by FPL in its sole discretion. The Builder's Risk Policy will be maintained in accordance with terms reasonably available in the insurance market for the construction of major solar electric generating facilities and shall cover physical loss to property at the Job Site which results from a Defect but will not cover the Defect, including the cost to remedy the Defect. FPL shall cause the underwriter of the Builder's Risk Policy to waive all rights of subrogation against Contractor and its Subcontractors for damages covered by the Builder's Risk Policy. If a loss is insured under the Builder's Risk Policy, FPL will prepare and submit to the insurer any claim and proof of loss in accordance with the terms of the Builder's Risk Policy, and Contractor shall provide FPL with such documentation as FPL may reasonably require in connection with the preparation of such claim and proof of loss. FPL shall use commercially reasonable efforts for the benefit of the Parties in pursuing any claim under the Builder's Risk Policy, including, if permitted by the Builder's Risk Policy, pursuit of partial payment for partial proof of loss and payment of undisputed amounts due under the Builder's Risk Policy, provided Contractor acknowledges and agrees that the Builder's Risk Policy may not require such partial payments. FPL shall keep the Contractor reasonably informed of the status of claims negotiations between FPL and the insurer under the Builder's Risk Policy and if Contractor is not satisfied with the progress of such negotiations, it shall have the right to address such dissatisfaction with FPL's management and FPL shall use reasonable efforts to address Contractor's concerns. Notwithstanding the foregoing and subject to FPL's obligation to use commercially reasonable efforts in pursuing claims under the Builder's Risk Policy, any decisions made in the settlement or negotiation of any claim under the Builder's Risk Policy shall be in FPL's sole discretion. Upon availability and reasonable prior notice, Contractor's authorized representative shall be entitled to receive a copy of the Builder's Risk Policy. Contractor is responsible for the deductible under the Builder's Risk Policy; provided, however, Contractor's responsibility therefor shall in no event exceed $[500,000] per occurrence.

9.10 FORM OF FPL'S POLICIES

9.10.1 FPL shall provide Contractor with a certificate of insurance evidencing those policies set forth in Section 9.9, FPL INSURANCE POLICIES. As it applies to this Agreement, FPL shall provide that the insurance required pursuant to Section 9.9, FPL INSURANCE POLICIES, shall, except for Workers' Compensation, name Contractor and its Subcontractors as additional insureds thereunder only as their respective interests may appear but only with respect to Work performed pursuant to the Agreement.

9.10.2 Contractor shall be responsible for the payment of all deductibles for such claims caused, directly or indirectly, through the acts or omissions of Contractor, any Affiliate thereof, any Subcontractor or Vendor, or anyone directly or indirectly employed by any of them, or anyone for whose acts such Person may be liable.

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9.11 CONTRACTOR'S ASSISTANCE

In the event a loss is sustained under any of FPL's policies, such loss will be adjusted by FPL and/or the Financing Parties with the insurance companies. Contractor will assist FPL and the Financing Parties in the adjustment of losses. In the event a loss is sustained under the Builder's Risk Policy, such loss will be adjusted by Contractor and FPL with the insurance companies. FPL and Contractor agree to waive all rights of recovery against each other, and shall cause their respective underwriters to waive all rights of subrogation, for damages caused by fire and/or other perils to the extent covered and paid for by the Cargo Insurance. Contractor shall cooperate with FPL in obtaining and maintaining the insurance policies of FPL and shall provide all Drawings, Final Plans, certificates and other information that FPL or its insurers may reasonably require. Upon FPL's reasonable request, Contractor shall with all due diligence comply with the conditions of FPL's insurance polices and all reasonable requirements of the insurers in connection with the settlement of claims, the recovery of losses and the prevention of accidents and shall bear at its own cost the consequences of any failure to do so.

9.12 RESPONSIBILITY FOR SAFE DELIVERY OF MATERIALS OF CONTRACTOR

In addition to Section 8.2., RISK OF LOSS, of Article VIII, RISK OF LOSS AND POSSESSION, Contractor shall comply with all warranty requirements or other requirements set forth in all policies, including transport or marine/inland marine cargo insurance policies.

9.13 NO LIMITATION ON LIABILITY

Nothing in this Article shall be deemed to limit Contractor's liability under the Contract Documents regardless of the insurance coverages required by this Article. Except for the coverage limits of liability for insurance companies set forth in Section 9.1, CONTRACTOR INSURANCE POLICIES, no limitation of liability provided to Contractor under the Contract Documents is intended nor shall run to the benefit of any insurance company or in any way prejudice, alter, diminish, abridge or reduce, in any respect, the amount of proceeds of insurance otherwise payable to FPL or the Financing Parties under coverage required to be carried by Contractor under the Contract Documents, it being the intent of the Parties that the full amount of insurance coverage bargained for be actually available notwithstanding any limitation of liability contained in the Contract Documents, if any. FPL assumes no responsibility for the solvency of any insurer or the failure of any insurer to settle any claim.

9.14 FPL CONTROLLED INSURANCE PROGRAM

FPL and Contractor agree that FPL may substitute its own Owner's Controlled Insurance Program ("OCIP") for the purpose of providing during the term of the Agreement Worker's Compensation insurance, Commercial General Liability insurance and other insurance requested by FPL that is typically covered by OCIPs. In such event, FPL shall procure and pay the costs for certain insurance coverages on behalf of Contractor and Subcontractors.

ARTICLE X.
SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE

10.1 GENERAL.

10.1.1 All start-up, synchronization, operation and testing conducted by Contractor shall be in accordance with the Contract Documents, applicable manufacturers' instructions and warranty requirements, Applicable Laws, Applicable Standards, Applicable Permits, Prudent Utility Practices and any and all applicable rules as agreed to by FPL and Contractor. Contractor shall provide FPL with at least thirty (30) days' advance written notice of the first Test that involves delivering energy to the Grid. In addition, no Test of the Plant that delivers electrical output shall be conducted unless Contractor gives prior written notice thereof as provided in Section 10.1.2, Test Notice. FPL, Financing Parties, the Utility, the Independent Engineer, all relevant Government Authorities and their respective authorized representatives shall have the right to inspect the Work and to be present during the start-up, synchronization, operation and testing of the Project pursuant to this Article.

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10.1.2 Test Notice.

(a) Prior to performing any Test, Contractor shall deliver to FPL a written notice thereof (a "Test Notice") specifying a date for commencement of any or all of the Tests. Contractor shall coordinate with FPL the scheduling of any Test and FPL shall coordinate such Test with the dispatch schedule for the Plant, so as not to interfere with FPL's or its Affiliates' obligations with respect thereto. Contractor shall deliver a Test Notice at least ten (10) Business Days prior to the commencement of any Test. FPL shall, within five (5) Business Days after its receipt of such Test Notice, deliver to Contractor a written notice:

(i) Accepting such Test Notice; or

(ii) Denying that the prerequisites for performing such Test have been completed and stating the facts upon which such reasonable denial is based.

(b) Upon receipt of notice denying that the prerequisites for performing such Test have been completed, Contractor shall take such action as is appropriate to remedy the conditions described in such notice from FPL. Following any such remedial action, Contractor shall deliver to FPL a new Test Notice conforming to the requirements of this Section 10.1.2, and the provisions of this Section 10.1.2, shall apply with respect to such new Test Notice in the same manner as they applied with respect to the original Test Notice.

(c) The foregoing procedure shall be repeated as often as necessary until FPL no longer rejects the Test Notice; provided, however, if Contractor is required to notify following receipt of FPL's written notice in which FPL denies that the prerequisites for performing a task have been completed, such renotification may be given within five (5) Business Days of such notice by FPL, and FPL shall have three (3) Business Days following the receipt of such resubmitted notice to file written objections as described above. Contractor shall reschedule Tests as requested by FPL to reasonably accommodate the schedules of Persons whom FPL deems necessary to attend the Tests. Contractor shall promptly notify FPL of any proposed change in the schedule of Tests and may not conduct any such test under such proposed changed schedule unless FPL receives reasonable advance notice of the actual date of commencement of such rescheduled test. FPL shall be responsible for notifying the Utility, the Financing Parties and the Independent Engineer for witnessing Tests. Contractor shall reimburse FPL for all additional direct costs reasonably and necessarily incurred by FPL due to Contractor's failure to provide written notice in accordance with this Section 10.2, or due to Contractor's failure to prepare any portion of the Work for inspections or testing after having provided notice to FPL of any such inspection or test.

10.2 SYNCHRONIZATION

Together with the notice of the Scheduled Synchronization Date, Contractor shall provide FPL a start-up and test schedule for the Project and copies of all manufacturers' specifications, schedules of protection schemes, and protection relay settings. Contractor shall promptly give FPL notice of any expected change in the Scheduled Synchronization Date or other information provided with the notice as described above (or any modifications thereto); provided that Contractor shall provide at least ten (10) days prior written notice of the actual synchronization date. Contractor shall perform the synchronization procedures in accordance with the Scope of Work and FPL's direction regarding Utility's requirements. Utility and its authorized representatives shall have the right to be present during the synchronization.

10.3 MECHANICAL COMPLETION

Upon satisfaction of all requirements for Mechanical Completion, Contractor shall provide FPL with a notice of Mechanical Completion. Within three (3) Business Days of receipt of such notice, FPL shall notify Contractor in writing whether or not Contractor has fulfilled the requirements of Mechanical Completion. If Contractor has not fulfilled such requirements for Mechanical Completion, FPL shall specify in such notice to Contractor in reasonable detail the reasons that the requirements for Mechanical Completion have not been met. Contractor shall promptly act to correct such deficiencies so as to achieve Mechanical Completion as soon as possible (and no later than by the applicable date set forth in Appendix C, Critical Milestones and

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Milestones, if such date has not already passed). Following any such remedial action, Contractor shall deliver to FPL a new notice of Mechanical Completion and the provisions of this Section 10.3, shall apply with respect to such new Mechanical Completion notice in the same manner as they applied to the original Mechanical Completion notice so long as, if the Guaranteed Provisional Acceptance Date shall have passed, Contractor is paying Schedule Liquidated Damages when due in accordance with Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES.

10.4 PERFORMANCE TESTS

10.4.1 Contractor is responsible for conducting the Tests and any required re-tests for the purposes of determining achievement of the Minimum Performance Level and the Final Acceptance Performance Level. Only after the Project:

(a) Has achieved Mechanical Completion;

(b) Has been synchronized with the Grid in accordance with the Scope of Work and Utility's requirements;

(c) Is capable of being operated safely, normally, reliably and continuously in accordance with the requirements of the Contract Documents at all operating conditions and modes specified in the Scope of Work (although minor portions of the Project not essential to its safe, continuous and reliable operation may remain to be completed); and

(d) Is ready for the Tests to be performed in accordance with the Contract Documents,

shall Contractor conduct the Tests.

10.4.2 Each Test shall be conducted in accordance with the terms of the Contract Documents, including the Scope of Work and Appendix HH, after complying with the notice provisions of Section 10.1.2, Test Notice. If the Project achieves the Minimum Performance Level, Contractor shall, upon satisfaction of the other requirements to Provisional Acceptance, submit a notice of Provisional Acceptance in accordance with Section 10.7, PROVISIONAL ACCEPTANCE. If the Project fails all or any part of the Tests, including, without limitation, the failure to achieve the Minimum Performance Level, Contractor shall take appropriate corrective action and the Tests shall be performed again. If the Project fails all or any part of the retest, Contractor shall take appropriate corrective action and the Tests shall be repeated. If Contractor fails to achieve the Minimum Performance Level and satisfy all of the other requirements of Provisional Acceptance on or prior to the Guaranteed Provisional Acceptance Date, Contractor shall pay Schedule Liquidated Damages in accordance with Section 11.2, SCHEDULE LIQUIDATED DAMAGES, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES. In addition, Contractor shall repeat the Tests in accordance with Section 11.6.1 during the applicable time periods set forth in Section 11.1, COMPLETION GUARANTEE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES. Contractor shall provide a written report of the results of each Test to FPL.

10.5 PERFORMANCE SHORTFALLS.

10.5.1 Prior to the Guaranteed Provisional Acceptance Date, if the Project has achieved the Minimum Performance Level necessary for Provisional Acceptance, as determined pursuant to Section 11.6, DETERMINATION OF PERFORMANCE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES (but not the Final Acceptance Performance Level), and the Project is capable of being operated safely, normally and continuously in accordance with the requirements of the Contract Documents at all operating levels specified in the Scope of Work (although minor portions of the Project not essential to its safe, continuous and reliable operation may remain to be completed), and after complying with the notice provisions of Section 10.1.2, Test Notice, Contractor may conduct the Tests again in accordance with the terms of the Contract Documents, including the Scope of Work, in order to attempt to achieve the Final Acceptance Performance Level. If the Project fails to achieve all or any part of the Final Acceptance Performance Level after the Guaranteed Provisional Acceptance Date, Contractor shall, subject to Contractor's rights set forth in the following sentence, submit a Remedial Plan reasonably acceptable to FPL and take appropriate corrective action and repeat the Tests. If the Project fails all or any part of the

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Final Acceptance Performance Level after the Guaranteed Provisional Acceptance Date but all other requirements for Final Acceptance have been met, including the achievement of the Minimum Performance Level, Contractor shall have the option of:

(a) Submitting a Remedial Plan reasonably acceptable to FPL and take appropriate corrective action and repeat the Tests; or

(b) Giving notice to FPL of its declaration of Final Acceptance and reducing the Contract Price based on the results of the last Guaranteed Performance Test performed (and during which the Noise Guarantee was simultaneously satisfied) prior to the issuance of such notice.

If Contractor selects option (b), above, (i) the Contract Price will be reduced to an amount equal to the Contract Price multiplied by the Payment Output Percentage and (ii) Contractor shall perform all Remediation Work requested by FPL related to Work not associated with the percentage of the Final Acceptance Performance Level that has been achieved. For example, if 75% of the Final Acceptance Performance Level is achieved, to the extent requested by FPL, Work not associated with achieving such 75% of the Final Acceptance Performance Level (such Work being referred to as the "Non-Accepted Work") shall be removed from the Property Site and the Property Site on which such Non-Accepted Work is located or performed shall be restored to the condition of the Property Site immediately prior to Initial Site Mobilization to the extent requested by FPL.

10.5.2 Notwithstanding the foregoing and subject to the terms and conditions contained herein, Contractor may repeat the Tests until the earliest of the:

(a) Date that is one hundred and eighty (180) days after the Guaranteed Provisional Acceptance Date;

(b) Achievement by Contractor of the Final Acceptance Performance Level; or

(c) Delivery by Contractor to FPL of Contractor's notice of declaration of Final Acceptance and reduction of the Contract Price in accordance with Section 10.5.1.

Contractor shall provide a written report of the results of each Test to FPL. The Minimum Performance Level, the Final Acceptance Performance Level and any other Net Energy Output used to calculate any reduction of Contract Price shall be achieved only while the Plant is operating in compliance with the Noise Guarantee (excluding for this purpose all waivers and variances permitted under Applicable Permits).

10.5.3 If the Final Acceptance Performance Level is not achieved within one hundred and eighty (180) days after the Guaranteed Provisional Acceptance Date and Contractor has not selected option (b) of Section 10.5.1, then the Contract Price will be automatically reduced to an amount equal to the Contract Price multiplied by the Payment Output Percentage, which Payment Output Percentage shall be based on the results of the last Guaranteed Performance Test performed (and during which the Noise Guarantee was simultaneously satisfied) prior to one hundred and eighty (180) days after the Guaranteed Provisional Acceptance Date.

10.5.4 At no time between the Provisional Acceptance Date and Final Acceptance shall the performance of the Project fall below the Minimum Performance Level, for reasons not due to FPL's operation of the Project or a Force Majeure Event.

10.6 PUNCH LIST.

10.6.1 At all times during performance of the Work, Contractor shall maintain a list setting forth parts of the Work which remain to be performed in order to confirm that the Work fully complies with the terms of the Contract Documents. Contractor shall promptly provide a copy of such list to FPL upon request. Contractor shall make such revisions to such list as and when requested by FPL from time to time.

10.6.2 No later than thirty (30) days before the Provisional Acceptance Date, Contractor shall prepare and submit to FPL a comprehensive list (the "Punch List") of items to be completed for the Project to reach Final Acceptance. The Punch List shall not include any item that affects the safety, reliability or operability of the Equipment, the Plant or any portion thereof or requires a shut-down or reduced operation of the

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Equipment, the Project or any portion thereof to be completed. Contractor shall make such revisions to the Punch List as and when reasonably requested by FPL from time to time.

10.6.3 The Parties agree that with respect to Punch List items that remain uncompleted and which are preventing Final Acceptance, it may be more expedient for FPL to complete such Punch List items, at its election and option. If the Parties are able to agree upon the commercial value of all items on the Punch List, and FPL so elects, at its sole discretion, FPL may, in lieu of requiring Contractor to complete any item on the Punch List, require Contractor to pay to FPL an amount equal to one hundred fifty percent (150%) of the commercial value of such Punch List item as reasonably determined by FPL. FPL shall have the right to offset such amount owed by Contractor against any amounts owed by FPL to Contractor at Final Acceptance, or otherwise under the Contract Documents.

10.7 PROVISIONAL ACCEPTANCE.

10.7.1 After completing the Tests in accordance with Section 10.4, TESTS, and Contractor determines that all of the requirements for Provisional Acceptance have been completed, Contractor shall provide written notice thereof to FPL.

10.7.2 Within three (3) Business Days following receipt by FPL of such notice of Provisional Acceptance, FPL shall notify Contractor in writing whether or not Contractor has fulfilled the requirements of Provisional Acceptance. If Contractor has fulfilled the requirements of Provisional Acceptance, FPL shall notify Contractor that it has achieved Provisional Acceptance. If Contractor has not fulfilled such requirements for Provisional Acceptance, FPL shall specify in such notice to Contractor in reasonable detail the reasons for determining that the requirements for Provisional Acceptance have not been met. Contractor shall promptly act to correct such deficiencies so as to achieve Provisional Acceptance as soon as possible (and no later than by the Guaranteed Provisional Acceptance Date if such date has not already passed). Following any such remedial action, Contractor shall deliver to FPL a new notice of Provisional Acceptance and the provisions of this Section 10.7.2, shall apply with respect to such new Provisional Acceptance notice in the same manner as they applied to the original Provisional Acceptance notice. The foregoing procedure shall be repeated as often as necessary, so long as Contractor is paying when due Schedule Liquidated Damages (if applicable), until acceptance by FPL of Contractor's Provisional Acceptance notice and delivery by FPL of its own notice to Contractor that Provisional Acceptance has been achieved. The date on which Provisional Acceptance is achieved by Contractor shall be the "Provisional Acceptance Date."

10.8 FINAL ACCEPTANCE OF THE PLANT

After achieving Provisional Acceptance in accordance with Section 10.7, PROVISIONAL ACCEPTANCE, when Contractor determines that all of the requirements for Final Acceptance have been completed (other than execution of the Final Acceptance Certificate by FPL), or when Contractor has elected to or is required to declare Final Acceptance pursuant to Section 10.5, PERFORMANCE SHORTFALLS, Contractor shall submit a proposed Final Acceptance Certificate, in substantially the form attached hereto as Appendix G, Form of Final Acceptance Certificate, to FPL. As soon thereafter as reasonably practicable, a team consisting of representatives of FPL, the Financing Parties, the Independent Engineer and Contractor shall make a final inspection of the Plant. Within ten (10) Business Days following such final inspection, FPL, with the consent of the Financing Parties, if applicable, shall notify Contractor in writing whether Contractor has fulfilled the requirements of the Contract Documents to reach Final Acceptance (other than execution of the Final Acceptance Certificate by FPL). If such requirements have been fulfilled, FPL will execute the proposed Final Acceptance Certificate. If the requirements for Final Acceptance have not been fulfilled, then FPL shall deliver a written notice to such effect to Contractor describing in reasonable detail the deficiencies noted and corrective action recommended, including projected target dates for the completion of such incomplete or remedial Work. Contractor shall promptly act to correct any such deficiencies. The procedure set forth in this Section 10.8, shall be repeated as necessary, until the earlier of: (i) the date on which Contractor has fulfilled the requirements for the issuance of the Final Acceptance Certificate and FPL executes such certificate; or (ii) termination of this Agreement.

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benefit of Contractor, in such order as FPL may elect in its sole discretion. In addition, FPL, in its sole discretion, may collect Schedule Liquidated Damages by drawing on the Letter of Credit if not timely paid by Contractor.

11.6 DETERMINATION OF PERFORMANCE.

11.6.1 Contractor's compliance with the Minimum Performance Level for purposes of achieving Provisional Acceptance shall be determined on the basis of the Tests conducted in accordance with Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE, and Appendix HH, and the results of such Tests shall be conclusive for such purpose. The Net Energy Output of the Plant shall be determined pursuant to the Guaranteed Performance Test and shall be measured while the Plant is operating in compliance with the Noise Guarantee (excluding for this purpose all waivers and variances permitted under Applicable Permits).

11.6.2 Contractor's compliance with the Minimum Performance Level and the Guaranteed Performance Level, or the extent of its failure to comply therewith, for purposes of achieving Final Acceptance shall be determined on the basis of the Tests conducted in accordance with Article X, SYNCHRONIZATION, TESTS, MECHANICAL COMPLETION, PROVISIONAL ACCEPTANCE AND FINAL ACCEPTANCE, and Appendix HH, and the results of such tests shall be conclusive for such purpose. The Net Energy Output of the Plant shall be determined pursuant to the Guaranteed Performance Test and shall be measured while the Plant is operating in compliance with the Noise Guarantee (excluding for this purpose all waivers and variances permitted under Applicable Permits).

11.7 ABSOLUTE OBLIGATIONS

The Parties understand and agree that Contractor's obligation to achieve the Minimum Performance Level simultaneously with achievement of the Noise Guarantee, is an absolute obligation, which must be achieved. Notwithstanding anything contained herein to the contrary, after the Project has achieved Provisional Acceptance and during the time period prior to Final Acceptance, the Project shall be capable of being operated in accordance with all of the Plant's operating procedures and all Applicable Laws, Applicable Permits and the other requirements of the Contract Documents, and all operating conditions specified in the Scope of Work, excluding for this purpose all waivers and variances permitted under Applicable Permits. The obligations set forth in this Section 11.7 are absolute obligations of Contractor regardless of the amounts and expenses required to be incurred by Contractor to satisfy such obligation, and notwithstanding that such amounts may exceed the Contract Price.

11.8 PARENT GUARANTY

Contractor's ultimate corporate parent is SunPower Corporation (the "Contractor Parent Company"). Concurrently with the execution of this Agreement, Contractor shall provide to FPL an irrevocable, unconditional guarantee in the form of Appendix I, Form of Contractor Parent Guaranty, duly executed by Contractor Parent Company for the benefit of FPL and the Financing Parties under terms and conditions acceptable to FPL and the Financing Parties ("Contractor Parent Guaranty"). In order to provide FPL and the Financing Parties with evidence of Contractor's and Contractor Parent Company's financial ability to complete the Project, Contractor agrees to comply with reasonable requests for financial information. After the Letter of Credit Termination Date, upon the occurrence of a Credit Trigger Event, at FPL's request, Contractor shall provide a Letter of Credit with a stated amount (or post other collateral, including cash in an amount) determined pursuant to paragraph 3 of Appendix E attached hereto in addition to the Contractor Parent Guaranty.

ARTICLE XII.
CONTRACTOR'S WARRANTIES

12.1 WARRANTIES.

12.1.1 Contractor warrants to FPL that all Equipment shall:

(a) Be new and of good quality;

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12.2.2 If Contractor fails to commence to complete the correction of any Defect or cure of any breach of warranty as required herein within five (5) days after receipt of notice from FPL to perform such obligations or thereafter fails to diligently continue to complete such corrections or cure, then FPL may correct (or cause to be corrected) such Defect or cure (or cause to be cured) such breach of warranty and Contractor shall be liable for all reasonable costs, charges, and expenses incurred by FPL in connection therewith (including attorneys' and other consultants' fees), and Contractor shall, within fifteen (15) days after request therefor, pay to FPL an amount equal to such costs, charges, and expenses. Any such request by FPL shall be accompanied by proper documentation evidencing such costs, charges and expenses. Such correction of a Defect or cure of a breach of warranty by FPL (or caused by FPL) shall be deemed performed by Contractor and the Warranty Period applicable thereto for such corrected or cured Work shall be extended in accordance with Section 12.1.4.

12.2.3 If, during the a given Warranty Period, Contractor shall change, repair or replace any Major Equipment item or component, FPL, in its reasonable discretion, may require Contractor to conduct and satisfactorily complete any test required by FPL with respect to the affected Equipment; provided, however, in connection with any performance of a test pursuant to this Section 12.2.3, appropriate allowance with respect to the performance of such Equipment shall be made for the fact that such Equipment may have operated prior thereto. If after running such test pursuant to this Section, the results indicate a degradation in the performance of the Project (as measured against the test results used to satisfy the requirements of Section 12.1.3) or the Project fails to satisfy any other Test, then Contractor shall repair, correct or replace such affected Equipment and re-run such test until the Project performs at a level consistent with the performance of the Project immediately prior to the change, repair or replacement of such Equipment.

12.3 PROPRIETARY RIGHTS

Without limiting any of the provisions of this Agreement, if FPL or Contractor is prevented from completing the Plant, the Work or any part thereof; or from the use, operation, or enjoyment of the Plant, the Work or any part thereof as a result of a claim, action or proceeding by any Person for unauthorized disclosure, use, infringement or misappropriation of any Intellectual Property Right arising from Contractor's performance (or that of its Subcontractors or Vendors) under the Contract Documents, including, without limitation, the Work, Equipment, the Contractor Deliverables or other items and services provided by Contractor or any Subcontractor or Vendor hereunder, Contractor shall promptly, but in no event later than thirty (30) days from the date of any action or proceeding, take all actions necessary to remove such impediment, including:

12.3.1 Secure termination of the injunction and procure for FPL or its Affiliates or assigns, as applicable, the right to use such materials, Equipment or Contractor Deliverables in connection with the operation and maintenance of the Project, without obligation or liability; or

12.3.2 Replace such materials, Equipment or Contractor Deliverables, with a non-infringing equivalent, or modify same to become non-infringing,

All at Contractor's sole expense, but subject to all the requirements of the Contract Documents.

12.4 REPAIRS AND TESTING BY FPL.

12.4.1 During the Warranty Period, without prior notice to Contractor and without affecting the warranties of Contractor hereunder, FPL shall be permitted to:

(a) Make repairs or replacements on Equipment so long as the repair or replacement involves the correct installation of spare parts and is otherwise conducted in accordance with the operation and maintenance manuals, the manufacturer specifications and the Procedures Manual; and

(b) Adjust or test Equipment as outlined in the instruction manuals provided by Contractor or any Subcontractor or Vendor.

12.4.2 In the event of an emergency and if, in the reasonable judgment of FPL, the delay that would result from giving notice to Contractor could cause serious loss or damage which could be prevented by immediate action, any action (including correction of Defects) may be taken by FPL or a third party chosen by FPL, without giving prior notice to Contractor, and in the case of a Defect, the reasonable cost of correction shall

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be paid by Contractor. In the event such action is taken by FPL, Contractor shall be promptly notified within five (5) Business Days after correction efforts are implemented, and shall assist whenever and wherever possible in making the necessary corrections.

12.5 VENDORS AND SUBCONTRACTORS

Contractor shall, for the protection of Contractor and FPL, obtain from the Vendors and Subcontractors such guarantees and warranties with respect to Work performed and Equipment supplied, used and installed hereunder as are reasonably obtainable, which guarantees and warranties shall equal or exceed those set forth in Section 12.1, WARRANTIES, and shall be made available and assignable to FPL and the Financing Parties to the full extent of the terms thereof upon the expiration of Contractor's warranty hereunder. FPL shall be an express third party beneficiary of all such guarantees and warranties. All such warranties obtained shall be in addition to, and shall not alter the warranties of, Contractor. Upon FPL's request, Contractor shall use all reasonable efforts to force Subcontractors to honor warranties including, but not limited to, filing suit to enforce same. To the extent available, FPL shall have the right to require Contractor to secure additional warranty or extended guarantee protection pursuant to a Change Order issued in accordance with the provisions of Article VI, CHANGE ORDERS. Upon the earlier of the Provisional Acceptance Date or termination of this Agreement, Contractor shall deliver to FPL copies of all relevant contracts providing for such guarantees and warranties.

12.6 ASSIGNMENT OF WARRANTIES

Upon the expiration of all of the Warranty Periods or termination of this Agreement, Contractor shall assign to FPL all warranties received by it from Subcontractors and Vendors or otherwise obtained under Section 12.5, VENDORS AND SUBCONTRACTORS (or the Plant or Work in the event of termination of this Agreement). Such assignment of warranties to FPL must also allow FPL to further assign such warranties. However, in the event that FPL makes any warranty claim against Contractor with respect to Equipment or services supplied in whole or in part by any Subcontractor or Vendor, and Contractor fulfills its obligations with respect to such claim by FPL, Contractor shall be entitled to enforce for its own benefit any warranty given by such Subcontractor or Vendor with respect to such Equipment and services.

12.7 SURVIVAL OF WARRANTIES

The provisions of this Article shall survive the expiration or termination of this Agreement.

ARTICLE XIII.
REPRESENTATIONS

13.1 REPRESENTATIONS AND WARRANTIES.

13.1.1 Contractor represents and warrants to FPL that:

(a) Contractor is a corporation, duly organized, validly existing, and in good standing under the laws of the State of Delaware and is duly authorized and qualified to conduct business in the State of Florida;

(b) Contractor has all requisite power and authority to conduct its business, own its properties and execute and deliver this Agreement and perform its obligations hereunder in accordance with the terms hereof;

(c) The execution, delivery, and performance of the Contract Documents have been duly authorized by all requisite corporate action and this Agreement constitutes the legal, valid and binding obligation of Contractor, enforceable against Contractor in accordance with its terms;

(d) Neither the execution, delivery or performance of the Contract Documents conflicts with, or results in a violation or breach of the terms, conditions or provisions of, or constitutes a default under, the organizational documents of Contractor or any agreement, contract, indenture or other instrument under which Contractor or its assets are bound, nor violates or conflicts with any Applicable Law or any judgment, decree, order, writ, injunction or award applicable to Contractor;

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(e) Contractor is not in violation of any Applicable Law or Applicable Permit, which violations, individually or in the aggregate, would affect its performance of its obligations under the Contract Documents;

(f) Except as described in Section 18.21, Contractor's License, Contractor is the holder of all governmental consents, licenses, permissions and other authorizations and Applicable Permits required to operate and conduct its business now and as contemplated by the Contract Documents, other than Contractor Permits and FPL Permits which will be obtained in accordance with the terms of the Contract Documents;

(g) There is no pending controversy, legal action, arbitration proceeding, administrative proceeding or investigation instituted, or to the best of Contractor's knowledge threatened, against or affecting, or that could affect, the legality, validity and enforceability of the Contract Documents or the performance by Contractor of its obligations under the Contract Documents, nor does Contractor know of any basis for any such controversy, action, proceeding or investigation;

(h) Contractor has examined this Agreement, including all Appendices attached hereto, thoroughly and become familiar with all its terms and provisions;

(i) Contractor, by itself and through its Subcontractors and Vendors, has the full experience and proper qualifications to design and perform the Work and to construct the Plant in accordance with the terms of the Contract Documents;

(j) Contractor has visited and examined the Property Site and is fully familiar with such Property Site and surrounding area and based on such visit and examination has no reason to believe that Contractor will be unable to complete the Work in accordance with the Contract Documents;

(k) To the best of its knowledge, Contractor has reviewed all other documents and information necessary and available to Contractor in order to ascertain the nature, location and scope of the Work, the character and accessibility of the Property Site, the existence of obstacles to construction of the Plant and performance of the Work, the availability of facilities and utilities, and the location and character of existing or adjacent work or structures;

(l) Contractor owns or has the right to use all patents, trademarks, service marks, tradenames, copyrights, licenses, franchises, permits and intellectual property rights necessary to perform the Work without conflict with the rights of others;

(m) Each of Contractor and the Contractor Parent Company is financially solvent, able to pay its debts as they mature, and possessed of sufficient working capital to complete its obligations under this Agreement;

(n) FPL may provide or may have provided Contractor with copies of certain studies, reports or other information (including oral statements) and Contractor represents and acknowledges that:

(i) All such documents or information have been or will be provided as background information and as an accommodation to Contractor;

(ii) FPL makes no representations or warranties with respect to the accuracy of such documents or the information (including oral statements) or opinions therein contained or expressed; and

(iii) It is not relying on FPL for any information, data, inferences, conclusions, or other information with respect to the Job Site (other than the boundary survey referred to in Section 4.7, DESCRIPTION OF PROPERTY SITE), including the surface conditions of the Job Site and the surrounding areas;

(o) All Persons who will perform any portion of the Work have and will have all business and professional certifications required by Applicable Law to perform their respective services under this Agreement;

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(p) The access rights granted to or obtained by Contractor to the Job Site are adequate for the performance of the Work and operation of the Plant; and

(q) The Plant will be designed and constructed to achieve or exceed the Net Energy Output Guarantee.

13.1.2 FPL represents and warrants to Contractor that:

(a) FPL is a corporation, duly organized, validly existing, and in good standing under the laws of Florida and is duly authorized and qualified to conduct business in the State of Florida;

(b) FPL has all requisite power and authority to conduct its business, own its properties and execute and deliver the Contract Documents and perform its obligations hereunder in accordance with the terms hereof;

(c) The execution, delivery, and performance of the Contract Documents have been duly authorized by all requisite corporation action and this Agreement constitutes the legal, valid and binding obligation of FPL, enforceable against FPL in accordance with its terms;

(d) Neither the execution, delivery or performance of the Contract Documents conflicts with, or results in a violation or breach of the terms, conditions or provisions of, or constitutes a default under, the organizational documents of FPL or any agreement, contract, indenture or other instrument under which FPL or its assets are bound, nor violates or conflicts with any Applicable Law or any judgment, decree, order, writ, injunction or award applicable to FPL;

(e) FPL is not in violation of any Applicable Law or Applicable Permit, which violations, individually or in the aggregate, would affect its performance of its obligations under the Contract Documents; and

(f) FPL is the holder of all governmental consents, licenses, permissions and other authorizations and Applicable Permits required to operate and conduct its business now and as contemplated by the Contract Documents, other than FPL Permits which will be obtained in accordance with the terms of the Contract Documents.

13.2 SURVIVAL OF REPRESENTATIONS AND WARRANTIES

The representations and warranties of the Parties herein shall survive execution and termination of this Agreement.

ARTICLE XIV.
FORCE MAJEURE AND FPL CAUSED DELAY

14.1 DEFINITION OF FORCE MAJEURE EVENT

14.1.1 As used herein, the term "Force Majeure Event" shall mean any event or circumstance, or combination of events or circumstances, that arises after the date hereof, is beyond the reasonable control of the Party claiming the Force Majeure Event, is unavoidable or could not be prevented or overcome by the reasonable efforts and due diligence of the Party claiming the Force Majeure Event and has an impact which will actually, demonstrably, adversely and materially affect such Party's ability to perform its obligations in accordance with the terms of the Contract Documents or has an impact which will actually, demonstrably, adversely and materially affect the Critical Path of the Work and performance of its obligations in accordance with the terms of the Contract Documents. Without limiting the generality of the foregoing, events that may give rise to a Force Majeure Event include, without limitation:

(a) Acts of God;

(b) Natural disasters;

(c) Fires;

(d) Earthquakes;

(e) Lightning;

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(f) Floods;

(g) Storms;

(h) Civil disturbances;

(i) Terrorism;

(j) Riots;

(k) War; and

(l) The action of or failure to act on the part of any Government Authority having or asserting jurisdiction that is binding upon the Parties and has been opposed by all reasonable means,

In each case, that meet the definition of Force Majeure Event as set forth above.

14.1.2 Notwithstanding the foregoing, the term "Force Majeure Event" does not include, without limitation:

(a) Strikes, work stoppages (or deteriorations), slowdowns or other labor actions, unless such strike, work stoppage or other labor action is a result of strike, work stoppage or other labor action originated by employees of the Party not claiming the Force Majeure Event;

(b) Any labor or manpower shortages;

(c) Unavailability, late delivery, failure, breakage or malfunction of equipment or materials or events that affect the cost of equipment or materials;

(d) Economic hardship (including lack of money);

(e) Perils of sea;

(f) Delays in transportation (including delays in clearing customs) other than delays in transportation resulting from accidents or closure of roads or other transportation route by Government Authorities;

(g) Changes in Applicable Laws;

(h) Weather conditions normally experienced in the geographic area of the Project, it being the intent of the Parties that only when the number of days lost as a result of adverse weather (as reported by the National Weather Service or a similar agency) exceeds the number usually encountered in the geographic area of the Project for any given month based on a ten (10) year average (as reported by the National Weather Service or a similar agency) will Contractor be allowed to claim a Force Majeure Event, subject however to the other requirements for an event or occurrence to be Force Majeure Event and the other requirements set forth in this Article;

(i) Actions of a Government Authority with respect to Contractor's compliance with Applicable Laws or Applicable Permits;

(j) Any failure by Contractor to obtain and/or maintain any Applicable Permit it is required to obtain and/or maintain hereunder;

(k) Any other act, omission, delay, default or failure (financial or otherwise) of a Subcontractor or Vendor; or

(l) Any surface or subsurface conditions at the Property Site (subject to Contractor's rights as provided in Section 3.4.4, Differing Condition, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR).

14.1.3 Notwithstanding the foregoing and solely for the purpose of conducting the acceptance testing provided for in Section 2 of Appendix HH – Acceptance Testing, the term "Force Majeure Event" includes solar conditions that do not meet the express criteria set forth in in Section 2 of Appendix HH – Acceptance

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Testing, subject however to the other requirements for an event or occurrence to be Force Majeure Event and the other requirements set forth in this Article.

14.2 NOTICE OF FORCE MAJEURE EVENT

The Party claiming a Force Majeure Event shall within five (5) Business Days after it knows or should have known of the occurrence of the Force Majeure Event (or in any event, no later than twenty (20) days after the commencement of the Force Majeure Event), give the other Party written notice describing the details of the cause and nature of the Force Majeure Event, the anticipated length of delay due to the Force Majeure Event and any other affect on the Party's performance of its obligations hereunder; provided that if the Force Majeure Event results in a breakdown of communications rendering it not reasonably practicable to give notice within the applicable time limit specified herein, then the Party claiming a Force Majeure Event shall give such notice as soon as reasonably practicable after the reinstatement of communications, but no later than five (5) Business Days after such reinstatement. Within fifteen (15) days after initial notification, such Party shall provide sufficient proof of the occurrence and duration of such Force Majeure Event to the other Party and shall thereafter provide the other Party with periodic supplemental updates to reflect any change in information given to the other Party as often as requested by the other Party. The Party claiming the Force Majeure Event shall give notice to the other Party of: (i) the cessation of the relevant Force Majeure Event; and (ii) the cessation of the effects of such Force Majeure Event on the performance by it of its obligations under the Contract Documents as soon as practicable after becoming aware thereof. No Force Majeure Event shall relieve any Party from performing those of its obligations that are not affected by the Force Majeure Event.

14.3 DELAY FROM FORCE MAJEURE EVENT

14.3.1 So long as the conditions set forth in this Section 14.3 are satisfied, and subject to Section 14.7, PERFORMANCE NOT EXCUSED, neither Party shall be responsible or liable for, or deemed in breach of this Agreement because of, any failure or delay in complying with its obligations under or pursuant to the Contract Documents to the extent that such failure has been caused, or contributed to, by one or more Force Majeure Events or its effects or by any combination thereof, and in such event:

(a) Except as otherwise provided herein, the performance by the Party claiming the Force Majeure Event of its obligations hereunder shall be suspended, and in the event that such Party is required to start or complete an action during a specific period of time, such start date or period for completion shall be extended, on the condition that:

(i) Such suspension of performance and extension of time shall be of no greater scope and of no longer duration than is required by the effects of the Force Majeure Event;

(ii) The Party claiming the Force Majeure Event complies with Section 14.2, NOTICE OF FORCE MAJEURE EVENT; and

(iii) The Party claiming the Force Majeure Event continually uses commercially reasonable efforts to alleviate and mitigate the cause and effect of the Force Majeure Event and remedy its inability to perform; and

(b) In the event Contractor desires to claim a Force Majeure Event, it must submit a request for Changes pursuant to Section 6.2, CHANGE ORDERS REQUESTED BY CONTRACTOR, of Article VI, CHANGE ORDERS.

14.3.2 Solely with respect to a Force Majeure Event described in Section 14.1.3, if such Force Majeure Event continues for sixty (60) consecutive days from the commencement of acceptance testing, then, solely for purposes of Section 11.2, FPL shall deem Contractor to have satisfied the Minimum Performance Level and Schedule Liquidated Damages shall not be payable. In such event, Contractor shall not be deemed to have achieved Provisional Acceptance until solar conditions exist that meet the express criteria set forth in in Section 2 of Appendix HH – Acceptance Testing and the Minimum Performance Level is achieved in accordance with Section 11.6.

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14.3.3 Contractor's failure to comply with this Section 14.3, shall constitute a waiver of any claims as a result of a Force Majeure Event.

14.4 REMOVAL OF FORCE MAJEURE

If, within a reasonable time after a Force Majeure Event that has caused Contractor to suspend or delay performance of the Work, action to be undertaken at the expense of FPL has been identified and recommended to Contractor, and Contractor has failed within five (5) days after receipt of notice thereof from FPL to take such action as Contractor could lawfully and reasonably initiate to remove or relieve either the Force Majeure Event or its direct or indirect effects, FPL may, in its sole discretion and after notice to Contractor, initiate such reasonable measures as will be designed to remove or relieve such Force Majeure Event or its direct or indirect effects and thereafter require Contractor to resume full or partial performance of the Work. To the extent Contractor's failure to take such measures results in expense in addition to what FPL would have paid to Contractor (whether as part of the original Contract Price or as additional compensation to the extent the requested measures constituted a Change Order altering the scope of the Work) had Contractor taken such measures, such additional expense shall be for Contractor's account.

14.5 NOTICE OF FPL CAUSED DELAY

14.5.1 In the event Contractor desires to claim an FPL Caused Delay, Contractor shall within five (5) Business Days after it knows or should have known of the occurrence of the FPL Caused Delay, give FPL written notice describing the details of the FPL Caused Delay, the anticipated length of such delay and any other affect on Contractor's performance of its obligations hereunder. Within fifteen (15) days after initial notification, Contractor shall:

(a) Provide to FPL demonstrable proof of the occurrence and duration of such FPL Caused Delay and, if requested by FPL, such proof shall be provided, and in any event verified, by an independent third party reasonably acceptable to FPL and Contractor at the sole cost and expense of Contractor; and

(b) Thereafter provide FPL with periodic supplemental updates to reflect any change in information given to FPL as often as requested by FPL.

14.5.2 In the event that Contractor claims an FPL Caused Delay in violation of this provision, FPL shall be entitled to set-off against any payments due to Contractor or draw upon any security provided by Contractor (including the Letter of Credit) to compensate FPL for all costs (including reasonable attorneys' and other consultants' fees) incurred in enforcing this Section 14.5.

14.6 DELAY FROM FPL CAUSED DELAY

14.6.1 So long as the conditions set forth in this Section 14.6, are satisfied and subject to Section 14.7, PERFORMANCE NOT EXCUSED, Contractor shall not be responsible or liable for, or deemed in breach of the Contract Documents because of, any failure or delay in completing the Work in accordance with the Project Schedule or achieving Provisional Acceptance by the Guaranteed Provisional Acceptance Date to the extent that such failure has been caused by one or more FPL Caused Delays, and in such event, except as otherwise provided herein, the start date or period for completion of any portion of the Work shall be extended, on the condition that:

(a) Such suspension of performance and extension of time shall be of no greater scope and of no longer duration than is required by the effects of the FPL Caused Delay;

(b) Contractor complies with Section 14.5, NOTICE OF FPL CAUSED DELAY; and

(c) Contractor provides all assistance reasonably requested by FPL for the elimination or mitigation of the FPL Caused Delay.

14.6.2 In the event Contractor desires to claim an FPL Caused Delay, it must submit a request for Changes pursuant to Section 6.2, CHANGE ORDERS REQUESTED BY CONTRACTOR, of Article VI, CHANGE ORDERS, and Contractor shall be entitled to suspension of performance or extension of time (including an extension of the Guaranteed Provisional Acceptance Date) together with demonstrated, justified and

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reasonable additional costs incurred by reason of such delay to the extent agreed upon by both Parties pursuant to a Change Order in accordance with Section 6.2, CHANGE ORDERS REQUESTED BY CONTRACTOR, of Article VI, CHANGE ORDERS. Failure to comply with the terms of this Section 14.6, shall constitute a waiver of any claims for an increase in the Project Schedule or the Contract Price as a result of an FPL Caused Delay.

14.7 PERFORMANCE NOT EXCUSED

The payment of money owed shall not be excused because of a Force Majeure Event or FPL Caused Delay. In addition, a Party shall not be excused under this Article from timely performance of its obligations hereunder to the extent that the claimed Force Majeure Event or FPL Caused Delay was caused by any negligent or intentional acts, errors, or omissions, or for any breach or default of the Contract Documents by such Party. Furthermore, no suspension of performance or extension of time shall relieve the Party benefiting therefrom from any liability for any breach of the obligations that were suspended or failure to comply with the time period that was extended to the extent such breach or failure occurred prior to the occurrence of the applicable Force Majeure Event or FPL Caused Delay. Notwithstanding anything contained herein to the contrary, Contractor shall not withdraw Contractor's Equipment and personnel from the Job Site or otherwise demobilize without the prior authorization of FPL. Contractor shall not be entitled to receive reimbursement for its costs of demobilization and/or remobilization as a result of any Force Majeure Event.

ARTICLE XV.
TERMINATION

15.1 CONTRACTOR EVENTS OF DEFAULT

The occurrence of any of the following events shall constitute an event of default by Contractor (each a "Contractor Event of Default"):

15.1.1 The failure of Contractor, subject to the grace period provided in Section 11.1, COMPLETION GUARANTEE, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES, to achieve Provisional Acceptance by the Guaranteed Provisional Acceptance Date;

15.1.2 Intentionally Deleted.

15.1.3 The failure of Contractor to achieve Final Acceptance within two hundred and twenty five (225) days after the Guaranteed Provisional Acceptance Date;

15.1.4 The failure of the Plant to continue to operate at Minimum Performance Level after Provisional Acceptance and prior to Final Acceptance, unless such failure is caused by FPL's failure to properly operate and maintain the Plant in accordance with Contractor's written instructions provided hereunder;

15.1.5 The Plant, during the period of time between Provisional Acceptance and Final Acceptance, is not capable of being operated in accordance with Plant operating procedures and all Applicable Laws and Applicable Permits, and other requirements of the Agreement, and all operating conditions specified in the Scope of Work;

15.1.6 The failure by Contractor to pay liquidated damages as required herein;

15.1.7 Any failure by Contractor to make any other payment or payments required to be made to FPL under the Contract Documents within five (5) Business Days after receipt of written notice from FPL of Contractor's failure to make such other payment or payments (except, in the case of payments other than Schedule Liquidated Damages, to the extent Contractor disputes such other payment or payments in good faith and in accordance with the terms of this Agreement);

15.1.8 Any of the following occurs:

(a) Contractor fails to supply sufficient skilled workers or suitable materials or equipment;

(b) Contractor fails to make prompt payments when due to Subcontractors or Vendors for labor, materials or equipment;

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(c) Contractor suspends performance of a material portion of the Work (other than as provided in: (i) Article XIV, FORCE MAJEURE AND FPL CAUSED DELAY; (ii) Section 15.4.1, Suspension by FPL for Convenience, (iii) Section 15.7, TERMINATION BY CONTRACTOR DUE TO FPL DEFAULT; or (iv) pursuant to a Change Order); or

(d) Contractor fails to comply with any provision of any Applicable Law,

and if in each paragraph (a) through (d) of this Section, such condition remains unremedied for thirty (30) days following written notice thereof by FPL, or for such longer period, not to exceed sixty (60) days, during which time Contractor diligently pursues the cure of such material breach, if such material breach is capable of being cured;

15.1.9 The failure by Contractor to deliver any recovery plan described in Section 5.3.3, of Section 5.3, PROJECT SCHEDULE, of Article V, PROJECT SCHEDULE, within thirty (30) days after the date such recovery plan is due pursuant to the terms of such Section, or following approval of a recovery plan pursuant to such Section, the failure of Contractor to meet the schedule set forth in such recovery plan;

15.1.10 Any breach by Contractor of any representation or warranty made by Contractor in Article XIII, REPRESENTATIONS;

15.1.11 Any breach by Contractor of any obligation, covenant or agreement of Contractor hereunder other than those breaches specified in this Section 15.1, and:

(a) Such breach is not cured by Contractor within fifteen (15) days after notice thereof from FPL; or

(b) If such breach is not capable of being cured within such fifteen (15) day period (as determined by FPL in its sole discretion), Contractor fails to:

(i) Commence to cure such breach within such fifteen (15) day period;

(ii) Thereafter diligently proceed to cure such breach in a manner satisfactory to FPL in its sole discretion;

(iii) Cure such breach within ninety (90) days after notice thereof from FPL;

15.1.12 Any of the following occurs:

(a) Contractor or Contractor Parent Company consents to the appointment of or taking possession by, a receiver, a trustee, custodian, or liquidator of itself or of a substantial part of its assets, or fails or admits in writing its inability to pay its debts generally as they become due, or makes a general assignment for the benefit of creditors;

(b) Contractor or the Contractor Parent Company files a voluntary petition in bankruptcy or a voluntary petition or an answer seeking reorganization in a proceeding under any applicable bankruptcy or insolvency laws or an answer admitting the material allegations of a petition filed against it in any such proceeding, or seeks relief by voluntary petition, answer or consent, under the provisions of any now existing or future bankruptcy, insolvency or other similar law providing for the liquidation, reorganization, or winding up of corporations, or providing for an agreement, composition, extension, or adjustment with its creditors;

(c) A substantial part of Contractor's or the Contractor Parent Company's assets is subject to the appointment of a receiver, trustee, liquidator, or custodian by court order and such order shall remain in effect for more than thirty (30) days; or

(d) Contractor or the Contractor Parent Company is adjudged bankrupt or insolvent, has any property sequestered by court order and such order shall remain in effect for more than thirty (30) days, or has filed against it a petition under any bankruptcy, reorganization, arrangement, insolvency, readjustment of debt, dissolution or liquidation law of any jurisdiction, whether now or hereafter in effect, and such petition shall not be dismissed within thirty (30) days of such filing;

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15.1.13 The dissolution of Contractor, except for the purpose of merger, consolidation or reorganization where the successor expressly assumes Contractor's obligations hereunder and such assignment and assumption does not materially adversely affect the ability of the successor to perform its obligations under the Contract Documents and the Parent Guaranty remains in full force and effect for the obligations of such successor;

15.1.14 The transfer by Contractor of all or a substantial portion of the:

(a) Rights and/or obligations of Contractor hereunder, except for an assignment permitted hereunder; or

(b) Assets or obligations of Contractor, except where the transferee expressly assumes the transferred obligations and such transfer does not materially adversely affect the ability of Contractor or the transferee, as applicable, to perform its obligations under the Contract Documents, as determined by FPL in its sole discretion;

15.1.15 The failure of Contractor to provide and maintain in full force and effect any Contractor Parent Guaranty as required pursuant to Section 11.8, PARENT GUARANTY, of Article XI, CONTRACTOR GUARANTEES AND LIQUIDATED DAMAGES and, in the event that a Credit Trigger Event has occurred after the Final Acceptance Date, the failure of Contractor to provide and maintain a Letter of Credit (or such other collateral permitted pursuant to such Section 11.8) in the face amount required in accordance with paragraph 3 of Appendix E – Credit Trigger Event;

15.1.16 Any failure by Contractor to maintain the insurance coverages required of it in accordance with Article IX, INSURANCE;

15.1.17 Any failure of Contractor to maintain the Letter of Credit in accordance with Section 7.5, LETTERS OF CREDIT, of Article VII, CONTRACT PRICE; PAYMENTS TO CONTRACTOR, including but not limited to any adjustment in the stated amount thereof (or posting of additional collateral permitted pursuant to such Section 7.5) upon the occurrence of a Credit Trigger Event; unless the available amount thereunder (as such available amount may be increased upon the occurrence of a Credit Trigger Event) has been drawn in full in accordance with the terms thereof;

15.1.18 Any abandonment of the Work by Contractor, where "Abandonment" for the purposes of this Section shall mean that Contractor has substantially reduced personnel at the Job Site or removed required equipment from the Job Site such that, in the opinion of an experienced construction manager, Contractor would not be capable of completing the Critical Milestones in accordance with the Project Schedule; or

15.1.19 The occurrence of a Credit Event of Default.

15.2 TERMINATION BY FPL DUE TO CONTRACTOR DEFAULT; OTHER REMEDIES.

15.2.1 Upon the occurrence of a Contractor Event of Default, FPL may, at its option, terminate this Agreement, without prejudice to any other rights and remedies available to FPL under this Agreement, by giving written notice thereof to Contractor, which termination shall be effective upon the giving of such notice by FPL.

15.2.2 In the event of a termination by FPL under this Section 15.2, FPL shall have the right to take possession of and use all of the Contractor Equipment located at the Job Site on the date of such termination for the purpose of completing the Work and may employ any other Person to complete the Work by whatever method that FPL may deem necessary. In addition, FPL may make such expenditures as in FPL's sole judgment will accomplish the timely completion of the Work in accordance with the terms hereof.

15.2.3 In the event of termination by FPL under this Section 15.2, Contractor shall not be entitled to receive any further payments under the Contract Documents (other than undisputed payments owed and payable to Contractor hereunder prior to the date of such termination).

15.2.4 In the event of termination by FPL under this Section 15.2, Contractor shall be responsible for and shall reimburse FPL for the following amounts:

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(a) All reasonable costs and expenses incurred by FPL to engage a substitute contractor to complete (or cure deficiencies in) the Work, including, without limitation, overhead and legal, engineering and other professional expenses;

(b) All reasonable costs and expenses incurred in connection with the termination of the Contract Documents, including costs and expenses incurred in connection with the obligations set forth under Section 15.9, OBLIGATIONS UPON TERMINATION;

(c) The amount by which:

(i) The cost reasonable to complete (or cure deficiencies in) the Work, exceeds

(ii) The balance of the Contract Price unpaid at the time of the termination; and

(d) All actual damages occasioned by reason of said default, except that Parties agree that Schedule Liquidated Damages shall apply in lieu of delay damages for late completion.

15.2.5 Upon the occurrence and during the continuance of a Contractor Event of Default but prior to termination of this Agreement by FPL, FPL may, without prejudice to any of its other rights or remedies:

(a) Seek performance by any guarantor of Contractor's obligations hereunder;

(b) Seek equitable relief to cause Contractor to take action or to refrain from taking action pursuant to this Agreement, or to make restitution of amounts improperly received under this Agreement;

(c) Make such payments or perform such obligations as are required to cure such Contractor Event of Default, and then draw on or make a claim against the Letter of Credit or other security provided pursuant to this Agreement for the cost of such payment or performance and/or offset the cost of such payment or performance against payments otherwise due to Contractor under this Agreement; provided that FPL shall be under no obligation to cure any such Contractor Event of Default;

(d) Seek damages as provided in Section 15.2.4, including proceeding against any bond, guarantee, letter of credit, or other security given by or for the benefit of Contractor for its performance under this Agreement;

(e) Require direct payment or co-payment to Subcontractors or Vendors and any such payments or co-payments shall be credited against amounts due to Contractor under the Agreement; or

(f) Assign to FPL any agreement or purchase order with a Subcontractor or Vendor, provided that:

(i) FPL shall assume the obligations under such agreement or purchase order accruing after the date of such assignment;

(ii) If requested by FPL, Contractor shall remain responsible for administering and managing such agreement or purchase order (including enforcing the warranty obligations thereunder); and

(iii) In no event shall Contractor be relieved of its obligation to achieve Provisional Acceptance or Final Acceptance as a result of such assignment.

15.3 TERMINATION BY FPL FOR CONVENIENCE.

15.3.1 FPL may terminate this Agreement at any time for any reason in its sole discretion by giving written notice thereof to Contractor, which termination shall be effective upon the giving of such notice by FPL. Upon receiving any such notice of termination, Contractor shall stop performing the Work and, except as otherwise directed by FPL, shall cancel as quickly as possible all orders placed by it with Subcontractors and Vendors and shall use all reasonable efforts to minimize cancellation charges and other costs and expenses associated with the termination of the Agreement. Contractor shall also promptly assign all subcontracts and purchase orders which FPL wishes to retain in accordance with Section 15.9, OBLIGATIONS UPON TERMINATION.

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15.3.2 In the event of a termination by FPL under Section 15.3.1, Contractor shall be entitled to receive, as its sole and exclusive remedy for such termination, a termination payment ("Termination Payment") equal to the termination amount as set forth in the Termination Payment Schedule.

15.3.3 Intentionally Deleted.

15.3.4 In addition to FPL's right to terminate set forth in Section 15.3.1 above, FPL may terminate this Agreement because any of the following occurs pursuant to the Power Plant Siting Act, § 403.501-518, Florida Statutes and/or Chapter 62-17, Part I, (§ 62-17.011-62-17.293) of the Florida Administrative Code, the procedural rule implementing the act or otherwise:

(a) FPL does not select the Project pursuant to the "Request for Proposals";

(b) The Siting Board does not issue a "Land Use Order" for the Project;

(c) The Siting Board does not issue a "Final Certification Order";

(d) The Florida Department of Environmental Protection does not issue the "Air Construction Permit";

(e) The State of Florida Public Service Commission does not issue a "Need Order" for the Project;

(f) The Project is unable to obtain the applicable local, county, state or federal permits not covered by the Power Plant Siting Act;

(g) The administrative law judge responsible for recommending the Project to the Governor fails to recommend the Project;

(h) The Governor fails to approve the Project;

(i) Any other Government Authority whose approval or recommendation is necessary for the Project to be constructed fails to grant such approval or give such recommendation; or

(j) As a condition of obtaining any of the foregoing approvals or recommendations, FPL is required to materially amend the proposal for the Project (as determined in FPL's sole discretion);

then Contractor shall not be entitled to receive any further payments under the Contract Documents, except for the applicable Termination Payment.

15.3.5 Any amount owed pursuant to this Section 15.3, shall be subject to adjustment to the extent any Work contains Defects.

15.4 SUSPENSION BY FPL FOR CONVENIENCE.

15.4.1 FPL may suspend all or a portion of the Work to be performed under the Contract Documents at any time for any reason in its sole discretion by giving written notice thereof to Contractor. Such suspension, not to exceed 90 days individually and 180 days total while this Agreement is in effect, shall continue for the period specified in the notice of suspension; provided that Contractor agrees to resume performance of the Work promptly upon receipt of notice from FPL. Upon receiving any such notice of suspension, unless the notice requires otherwise, Contractor shall:

(a) Immediately discontinue the Work on the date and to the extent specified in the notice;

(b) Place no further orders or subcontracts for Equipment, services or facilities with respect to suspended Work, other than to the extent required in the notice;

(c) Promptly make every reasonable effort to obtain suspension, with terms reasonably satisfactory to FPL, of all orders, subcontracts and rental agreements to the extent they relate to performance of suspended Work;

(d) Continue to protect and maintain the Work performed, including those portions on which Work has been suspended; and

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(e) Take any other reasonable steps to minimize costs and expenses associated with such suspension.

15.4.2 Except as provided in Section 15.4.3, below, as full compensation for any suspension under this Section, Contractor will be reimbursed by FPL for the costs, as reasonably incurred, without duplication of any item, to the extent that such costs directly result from such suspension of the Work and to the extent that they do not reflect reimbursement for Contractor's, Vendors' or Subcontractors' anticipated profit from unperformed Work, including all necessary and reasonable costs incurred in connection with demobilization and remobilization of Contractor's facility and Labor and Contractor Equipment, plus an amount equal to 15% of such amounts.

15.4.3 Upon delivery of notice by FPL to Contractor to resume suspended Work, Contractor shall, as promptly as reasonably possible, resume performance under the Contract Documents to the extent required in the notice. Contractor may request a Change Order as a result of a suspension of Work under this Section within fourteen (14) days after receipt of notice to resume the suspended Work; provided that such suspension was not due to Contractor's negligence, willful misconduct or noncompliance with the terms of this Agreement. Contractor shall submit to FPL a request for Changes in accordance with Article VI, CHANGE ORDERS, and such request shall be accompanied by sufficient documentation setting forth the schedule impact and monetary extent of such claim in sufficient detail to permit thorough analysis by FPL; provided that if such information is not available within such fourteen (14) day period, Contractor shall notify FPL of such within such fourteen (14) day period and provide an expected date (which shall be as soon as reasonably practicable) for providing such information. If Contractor does not submit a request for Changes within such fourteen (14) day period and provide the information regarding schedule and monetary impact as required above within such fourteen (14) day period (or by the expected date if not possible during such fourteen (14) day period), Contractor shall not be entitled to any additional consideration or other amendments hereto and shall be deemed to have waived all claims and offsets against FPL as a result of the suspension of Work. Contractor shall permit access by FPL to pertinent records for purposes of reviewing the claims by Contractor of schedule and monetary impact.

15.4.4 Contractor shall not have any recourse to the provisions of Sections 15.4.2 or 15.4.3 if and to the extent that any suspension by FPL under this Section 15.4.1 occurs contemporaneously with any Force Majeure Event, FPL Caused Delay or a breach of Contractor's obligations under this Agreement.

15.5 [INTENTIONALLY DELETED]

15.6 FPL EVENTS OF DEFAULT

The occurrence and continuation of any of the following events shall constitute an event of default by FPL (each, an "FPL Event of Default"):

15.6.1 A failure by FPL to make payment of any undisputed amount when due, and such breach is not cured by FPL within fifteen (15) days after FPL's receipt of notice thereof from Contractor; or

15.6.2 Any breach by FPL of any representation or warranty made by FPL in Article XIII, REPRESENTATIONS;

15.6.3 Any of the following occurs:

(a) FPL consents to the appointment of or taking possession by, a receiver, a trustee, custodian, or liquidator of itself or of a substantial part of its assets, or fails or admits in writing its inability to pay its debts generally as they become due, or makes a general assignment for the benefit of creditors;

(b) FPL files a voluntary petition in bankruptcy or a voluntary petition or an answer seeking reorganization in a proceeding under any applicable bankruptcy or insolvency laws or an answer admitting the material allegations of a petition filed against it in any such proceeding, or seeks relief by voluntary petition, answer or consent, under the provisions of any now existing or future bankruptcy, insolvency or other similar law providing for the liquidation, reorganization, or winding up of corporations, or providing for an agreement, composition, extension, or adjustment with its creditors;

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(c) A substantial part of FPL's assets is subject to the appointment of a receiver, trustee, liquidator, or custodian by court order and such order shall remain in effect for more than thirty (30) days; or

(d) FPL is adjudged bankrupt or insolvent, has any property sequestered by court order and such order shall remain in effect for more than thirty (30) days, or has filed against it a petition under any bankruptcy, reorganization, arrangement, insolvency, readjustment of debt, dissolution or liquidation law of any jurisdiction, whether now or hereafter in effect, and such petition shall not be dismissed within thirty (30) days of such filing.

15.6.4 Any breach by FPL of any obligation, covenant or agreement of FPL hereunder other than those breaches specified in this Section 15.6, and:

(a) Such breach is not cured by FPL within fifteen (15) days after notice thereof from Contractor; or

(b) If such breach is not capable of being cured within such fifteen (15) day period (as determined by Contractor in its sole discretion), FPL fails to:

(i) Commence to cure such breach within such fifteen (15) day period;

(ii) Thereafter diligently proceed to cure such breach in a manner satisfactory to Contractor in its sole discretion; or

(iii) Cure such breach within ninety (90) days after notice thereof from Contractor.

15.6.5 The dissolution of FPL, except for the purpose of merger, consolidation or reorganization where the successor expressly assumes FPL's obligations hereunder and such assignment and assumption does not materially adversely affect the ability of the successor to perform its obligations under the Contract Documents.

15.6.6 The transfer by FPL of all or a substantial portion of the:

(a) Rights and/or obligations of FPL hereunder, except for an assignment permitted hereunder; or

(b) Assets or obligations of FPL, except where the transferee expressly assumes the transferred obligations and such transfer does not materially adversely affect the ability of FPL or the transferee, as applicable, to perform its obligations under the Contract Documents, as determined by Contractor in its sole discretion;

15.6.7 Any failure by FPL to maintain the insurance coverages required of it in accordance with Article IX, INSURANCE;

15.7 TERMINATION BY CONTRACTOR DUE TO FPL DEFAULT.

15.7.1 Subject to Section 15.7.2, below, upon the occurrence and during the continuance of an FPL Event of Default beyond the applicable grace period, Contractor may terminate this Agreement thirty (30) Days after giving written notice thereof to FPL so long as the amount owed by FPL (other than any amount disputed in accordance with the terms of this Agreement) is not paid within such period.

15.7.2 In the event of such termination, Contractor shall be entitled to receive an amount equal to the Termination Payment as its sole and exclusive remedy for such termination.

15.8 CONTINUING OBLIGATIONS AND REMEDIES DURING EVENT OF DEFAULT

In the event of the occurrence of any default hereunder:

15.8.1 Neither Party shall be relieved of any of its liabilities or obligations hereunder, unless and until such liabilities and obligations are terminated in accordance with the provisions hereof; and

15.8.2 Each Party shall have the right to pursue any right or remedy available to it, hereunder.

15.9 OBLIGATIONS UPON TERMINATION

Upon a termination of this Agreement pursuant to Section 15.2:

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15.9.1 Contractor shall leave the Job Site and remove from the Job Site all Contractor Equipment, waste, rubbish and Hazardous Material as FPL may request;

15.9.2 FPL shall take possession of the Job Site and of the Equipment (whether at the Job Site, in transit or otherwise);

15.9.3 Contractor shall promptly assign to FPL or its designee any contract rights (including warranties, licenses, patents and copyrights) that it has to any and all Equipment and the Work, including, without limitation, contracts with Subcontractors and Vendors, and Contractor shall execute such documents as may be reasonably requested by FPL to evidence such assignment, subject to FPL's assumption of same and, if required, FPL's adequate assurance to such Subcontractors or Vendors regarding FPL's ability to pay;

15.9.4 Contractor shall promptly furnish FPL with copies of all Drawings and, to the extent available, Final Plans, and copies of all computer files containing Drawings or Final Plans;

15.9.5 Contractor hereby grants FPL and its designee with the right to use, free of charge, all patented, copyrighted and other proprietary information relating to the Work that FPL deems necessary to complete the Work, and Contractor shall execute such documents as may be reasonably requested by FPL to evidence such right;

15.9.6 Contractor shall assist FPL in preparing an inventory of all Equipment in use or in storage at the Job Site;

15.9.7 Contractor shall perform all Remediation Work requested by FPL; and

15.9.8 Contractor shall take such other action as required hereunder upon termination of this Agreement.

15.10 TERMINATION AND SURVIVAL OF TERMS

Upon termination of this Agreement pursuant to this Article, the rights and obligations of the Parties hereunder shall terminate, except for the rights and obligations:

15.10.1 Accrued as of the date of termination;

15.10.2 Arising out of events occurring prior to the date of termination; and

15.10.3 Of the Parties which survive termination, including the rights and obligations forth in Articles XII, CONTRACTOR'S WARRANTIES, and XIII, REPRESENTATIONS.

ARTICLE XVI.
INDEMNIFICATION

16.1 CONTRACTOR INDEMNIFICATION

Contractor agrees to reimburse, indemnify, defend and hold FPL, the Financing Parties and their Affiliates and each of their respective directors, officers, employees, representatives, agents, advisors, consultants, counsel and assigns harmless from and against, on an After-Tax Basis, any and all losses, claims, obligations, demands, assessments, penalties, liabilities, costs, damages and expenses (including reasonable attorneys' fees and expenses) (collectively, "Damages") asserted against or incurred by such indemnitees by reason of or resulting from any and all of the following:

16.1.1 Any bodily injury, death or damage to property caused by any act or omission (including strict liability) or willful misconduct relating to or arising out of the performance of the Work or any curative action under any warranty following performance of the Work, of Contractor or any Affiliate thereof, any Subcontractor or Vendor, or anyone directly or indirectly employed by any of them, or anyone for whose acts such Person may be liable;

16.1.2 Any third party claims resulting in bodily or property damage arising out of defective and/or nonconforming Work relating to or arising out of the performance of the Work;

16.1.3 Claims by any Government Authority for any Contractor Taxes;

16.1.4 Any pollution or contamination which originates from sources in Contractor's or its Subcontractors' or Vendors' possession, use or control or caused by the release by Contractor or its Subcontractors or Vendors

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(excluding Pre-Existing Hazardous Material other than as provided in (e) below), including, without limitation, from Hazardous Material, toxic waste, industrial hazards, sanitary waste, fuel, lubricant, motor oil, paint, solvent, bilge and garbage;

16.1.5 Any release or exacerbation of Pre-Existing Hazardous Materials or rendering removal or remediation of Pre-Existing Hazardous Materials more costly, which in any of such events is caused by any negligent act or omission of Contractor or any Affiliate thereof, any Subcontractor or Vendor, or anyone directly or indirectly employed by any of them, or anyone for whose acts such Person may be liable;

16.1.6 To the extent FPL has paid all undisputed amounts due pursuant to the Contract Documents, any Lien, as set forth in Section 3.25, CLAIMS AND LIENS FOR LABOR AND MATERIALS, of Article III, CERTAIN OBLIGATIONS AND RESPONSIBILITIES OF CONTRACTOR, on the Equipment, the Job Site or any fixtures or personal property included in the Work (whether or not any such Lien is valid or enforceable) created by, through or under, or as a result of any act or omission (or alleged act or omission) of, Contractor or any Subcontractor, Vendor or other Person providing labor or materials in connection with the Work;

16.1.7 Any claim, action or proceeding by any Person for unauthorized disclosure, use, infringement or misappropriation of any Intellectual Property Right arising from:

(a) Contractor's performance (or that of its Affiliates, Subcontractors or Vendors) under the Contract Documents, including, without limitation, the Work, Equipment, Drawings, Final Plans or other items and services provided by Contractor or any Subcontractor or Vendor hereunder;

(b) The use or ownership of any Contractor Deliverable;

(c) Any license granted hereunder; or

(d) The design, engineering, construction, use, operation or ownership of the Plant or any portion thereof;.

(Without limiting the provisions of Section 12.3, PROPRIETARY RIGHTS, of Article XII, CONTRACTOR'S WARRANTIES, if FPL is enjoined from completing the Project or any part thereof, or from the use, operation or enjoyment of the Project or any part thereof, as a result of such claim or legal action or any litigation based thereon, Contractor shall promptly use its best efforts to have such injunction removed at no cost to FPL.)

16.1.8 Any vitiation of any insurance policy procured under Article IX, INSURANCE, as a result of Contractor's failure to comply with any of the requirements set forth in such policy or any other act by Contractor or any Subcontractor or Vendor;

16.1.9 Any failure of the Project, as designed, constructed or completed by Contractor, to comply with, or be capable of operating in compliance with, Applicable Laws or the conditions or provisions of Applicable Permits;

16.1.10 Any failure of Contractor to comply with Applicable Laws or the conditions or provisions of Applicable Permits; and

16.1.11 Any claims with respect to employer's liability or worker's compensation filed by any employee of Contractor or any of its Subcontractors or Vendors.

16.2 FPL INDEMNIFICATION

FPL agrees to reimburse, indemnify, defend and hold Contractor and its Affiliates and each of their respective directors, officers, employees, representatives, agents, advisors, consultants and counsel harmless from and against, on an After-Tax Basis, any and all Damages asserted against or incurred by such indemnitees by reason of or resulting from any and all of the following:

16.2.1 Any bodily injury, death or damage to property caused by (a) any act or omission (including strict liability) or willful misconduct of FPL or its agents or employees or others under FPL's direct control or (b) a breach by FPL of its obligations hereunder;

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16.2.2 Claims by any Government Authority for any FPL Taxes;

16.2.3 Any Pre-Existing Hazardous Material on the Property Site, except to the extent covered by Section 16.1.5, Contractor Release or Exacerbation; and

16.2.4 Any claims with respect to employer's liability or worker's compensation filed by any employee of FPL.

16.3 CONDITIONS OF INDEMNIFICATION

The respective rights and obligations of the Parties and the other indemnitees under this Article with respect to claims resulting from the assertion of liability by third parties shall be subject to the following terms and conditions:

16.3.1 *Notice of Proceedings*. Within fourteen (14) days (or such earlier time as might be required to avoid prejudicing the indemnifying Party's position) after receipt of notice of commencement of any legal action or of any claims against such indemnitee in respect of which indemnification will be sought, the Person claiming to be indemnified under the terms of this Section (the "Indemnified Person") shall give the Party from which indemnification is sought (the "Indemnifying Party") written notice thereof, together with a copy of such claim, process or other legal pleading. Failure of the Indemnified Person to give such notice will not reduce or relieve the Indemnifying Party of liability hereunder unless and to the extent that the Indemnifying Party was precluded from defending such claim, action, suit or proceeding as a result of the failure of the Indemnified Person to give such notice. In any event, the failure to so notify shall not relieve the Indemnifying Party from any liability that it may have to the Indemnified Person otherwise than under this Article.

16.3.2 *Conduct of Proceedings*. Each Party and each other indemnitee shall have the right, but not the obligation, to contest, defend and litigate any claim, action, suit or proceeding by any third party alleged or asserted against it arising out of any matter in respect of which it is entitled to be indemnified hereunder and the reasonable costs and expenses thereof (including reasonable attorneys' fees and expert witness fees) shall be subject to the said indemnity; provided that the indemnifying Party shall be entitled, at its option, to assume and control the defense of such claim; action, suit or proceeding at its expense upon its giving written notice thereof to the Indemnified Person. The Indemnified Person shall provide reasonable assistance to the Indemnifying Party, at the Indemnifying Party's expense, in connection with such claim, action, suit or proceeding. Upon such assumption, the Indemnifying Party shall reimburse the Indemnified Person for the reasonable costs and expenses previously incurred by it prior to the assumption of such defense by the Indemnifying Party. The Indemnifying Party shall keep the Indemnified Person informed as to the status and progress of such claim, action, suit or proceeding. Except as set forth in paragraph (c) below, in the event the Indemnifying Party assumes the control of the defense, the Indemnifying Party will not be liable to the Indemnified Person under this Article for any legal fees or expenses subsequently incurred by the Indemnified Person in connection with such defense. The Indemnifying Party shall control the settlement of all claims over which it has assumed the defense; provided, however, that the Indemnifying Party shall not agree to or conclude any settlement that affects the Indemnified Person without the prior written approval of the Indemnified Person, (whose said approval shall not be unreasonably withheld).

16.3.3 *Representation*. In the event the Indemnifying Party assumes control of the defense, the Indemnified Person shall have the right to employ its own counsel and such counsel may participate in such claim, action, suit or proceeding, but the fees and expenses of such counsel shall be at the expense of such Indemnified Person, when and as incurred, unless the:

(a) Employment of counsel by such Indemnified Person has been authorized in writing by the Indemnifying Party;

(b) Indemnified Person shall have reasonably concluded that there may be a conflict of interest between the Indemnifying Party and the Indemnified Person in the conduct of the defense of such action; or

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(c) Indemnified Person shall have reasonably concluded and specifically notified the Indemnifying Party either that there may be specific defense available to it which are different from or additional to those available to the Indemnifying Party.

If any of the preceding clauses (a) through (c) shall be applicable, then counsel for the Indemnified Person shall have the right to direct the defense of such claim, action, suit or proceeding on behalf of the Indemnified Person and the reasonable fees and expenses of such counsel shall be reimbursed by the Indemnifying Party.

16.4 CONTRIBUTORY NEGLIGENCE

If the joint, concurring, comparative or contributory fault, negligence or willful misconduct of the Parties gives rise to Damages for which a Party is entitled to indemnification under this Article, then such Damages shall be allocated between the Parties in proportion to their respective degrees of fault, negligence or willful misconduct contributing to such Damages.

16.5 REMEDIES NOT EXCLUSIVE

The rights under this Article shall not be exclusive with respect to any other right or remedy provided for in the Contract Documents.

16.6 PAYMENT

All payments required to be made under this Article shall be made on an After-Tax Basis and within thirty (30) days of demand therefor.

16.7 SURVIVAL OF INDEMNIFICATION

The provisions of this Article shall survive the Final Acceptance Date and the termination of this Agreement.

ARTICLE XVII.
DISPUTE RESOLUTION

17.1 FRIENDLY CONSULTATION

In the event of any dispute, controversy or claim between the Parties arising out of or relating to the Contract Documents, or the breach, termination or invalidity thereof (collectively, a "Dispute"), the Parties shall attempt in the first instance to resolve such Dispute through friendly consultations between the Parties. If such consultations do not result in a resolution of the Dispute within thirty (30) days after notice of a Dispute is delivered by either Party, then either Party may pursue all of its remedies available pursuant to the Contract Documents. The Parties agree to attempt to resolve all Disputes arising hereunder promptly, equitably and in a good faith manner. The Parties further agree to provide each other with reasonable access during normal business hours to any and all non-privileged records, information and data pertaining to such Dispute.

17.2 LITIGATION.

17.2.1 If a Dispute cannot be resolved pursuant to Section 17.1, FRIENDLY CONSULTATION, and in the event of litigation arising hereunder, the Parties agree that the venue for such litigation shall be the courts of the State of Florida in Miami-Dade County or Palm Beach County, Florida or the United States District Court for the Southern District of Florida, unless such other location or forum is mutually agreed. The Parties irrevocably waive any objection which any of them may now or hereafter have to the bringing of any such action or proceeding in such respective jurisdictions, including any objection to the laying of venue based on the grounds of forum non conveniens and any objection based on the grounds of lack of in personam jurisdiction. To facilitate the comprehensive resolution of related disputes, and upon the sole discretion and request of FPL, Contractor agrees and will stipulate in any proceeding to the consolidation of any litigation or other proceeding arising out of or relating to this Agreement with any other litigation or other proceeding arising out of or relating to any other agreement relating to the Project.

17.2.2 IN ANY LITIGATION ARISING FROM OR RELATED TO THE CONTRACT DOCUMENTS, THE PARTIES HERETO EACH HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE THE RIGHT EACH MAY HAVE TO A TRIAL BY JURY WITH RESPECT TO ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER OR IN CONNECTION WITH THE

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CONTRACT DOCUMENTS, OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF EITHER PARTY TO THE CONTRACT DOCUMENTS. THIS PROVISION IS A MATERIAL INDUCEMENT FOR FPL AND CONTRACTOR TO ENTER INTO THIS AGREEMENT.

17.2.3 The rights and obligations of the Parties under this Article shall not be impaired, reduced or otherwise affected as a result of any of the following the:

(a) Receipt by a Party from any third party of any amounts in reimbursement of Damages that are the subject of the Dispute; or

(b) Assignment or transfer by either Party of any or all of its rights and/or obligations under the Contract Documents as permitted hereunder.

17.2.4 In the event of any Dispute pursuant to this Article XVII, Dispute Resolution, the prevailing Party shall be entitled to recover its reasonable attorneys' fees and costs incurred in connection therewith.

17.3 CONTINUING OBLIGATIONS AND RIGHTS

When any Dispute occurs and is the subject of friendly consultations or litigation, Contractor shall continue the Work in accordance with the Project Schedule and the terms hereof and FPL shall continue to make payments of undisputed amounts in accordance with the Contract Documents, and the Parties shall otherwise continue to exercise their rights, and fulfill their respective obligations, under the Contract Documents.

17.4 TOLLING STATUTE OF LIMITATIONS

All applicable statutes of limitation and defenses based upon the passage of time and similar contractual limitations shall be tolled while the procedures specified in this Article are pending. The Parties will take such action, if any, required to effectuate such tolling. Without prejudice to the procedures specified in this Article, a Party may file a complaint for statute of limitations purposes, if in its sole judgment such action may be necessary to preserve its claims or defenses. Despite such action, the Parties will continue to participate in good faith in the procedures specified in this Article.

17.5 AUDIT RIGHTS

In the event of a claim by FPL under this Agreement involving an amount greater than Fifty Thousand Dollars ($50,000), Contractor shall grant audit rights to FPL with respect to all relevant documentation pertaining to such claim

ARTICLE XVIII.
MISCELLANEOUS

18.1 ASSIGNMENT.

18.1.1 Except as expressly permitted in the Contract Documents, Contractor may not assign this Agreement, the Contract Documents or any portion hereof, or any of the rights or obligations hereunder, without the prior written consent of FPL, which consent shall not be unreasonably delayed. This Agreement shall inure to the benefit of, and be binding upon, the successors and permitted assigns of the Parties.

18.1.2 FPL shall be entitled to assign this Agreement, the Contract Documents and its rights and obligations hereunder (a) to any Affiliate, without the consent of Contractor and (b) to any other Person, with the consent of Contractor, which consent shall not be unreasonably withheld or delayed, and Contractor shall release FPL from all obligations hereunder upon any such assignment; provided, however, that notwithstanding any assignment pursuant to clause (a) above, FPL shall remain responsible for all financial obligations under this Agreement. In addition, Contractor hereby consents to the granting of a security interest in and an assignment by FPL of the Contract Documents and its rights herein to the Financing

Parties and their successors, assigns and designees. In furtherance of the foregoing, Contractor acknowledges that the Financing Parties may under certain circumstances assume the interests and rights of FPL under the Contract Documents.

18.1.3 Contractor acknowledges that the Financing Parties may under certain circumstances foreclose upon and sell, or cause FPL to sell or lease the Project and cause any new lessee or purchaser of the Plant to assume all of the interests, rights and obligations of FPL arising under the Contract Documents. In such event, Contractor agrees to the assignment by FPL and the Financing Parties of the Contract Documents and its rights herein to such purchaser or lessee and shall release FPL and the Financing Parties from all obligations hereunder upon any such assignment.

18.2 GOOD FAITH DEALINGS; AUTHORSHIP

The Parties undertake to act fairly and in good faith in relation to the performance and implementation of the Contract Documents and to take such other reasonable measures as may be necessary for the realization of its purposes and objectives. The Parties collectively have prepared the Contract Documents, and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of the Contract Documents or any part hereof.

18.3 CONFIDENTIALITY.

18.3.1 For purposes of this Agreement, "Confidential Information" shall mean:

(a) The contents of the Contract Documents;

(b) Any information relating to the negotiations or performance of the Contract Documents; and

(c) Any information provided pursuant to the Contract Documents relating to the Project, Plant, FPL, Contractor or their Affiliates which:

(i) The disclosing Party designates in writing as confidential, proprietary or the like and which is received by the other Party;

(ii) By its nature is such that the receiving Party should reasonably conclude that possession of such information is of material commercial or competitive value to the disclosing Party;

(iii) Relates to the configuration, operation, management processes or profitability of the Plant; or

(iv) Relates to Project partners or prospective Project partners of FPL, including the names thereof.

18.3.2 Information shall be Confidential Information for the purposes hereof regardless of:

(a) The form in which it is communicated or maintained (whether oral, written, electronic or visual);

(b) Whether of a business, financial, legal, technical, managerial or other nature; and

(c) Whether prepared by the disclosing Party or otherwise.

18.3.3 Each Party agrees to hold all Confidential Information in confidence and not disclose it other than to its Affiliates, contractors (or potential contractors), subcontractors, vendors, consultants, advisors, Financing Parties (or potential Financing Parties), employees, directors, officers, agents, advisors or representatives (collectively, the "Personnel") for purposes of the Project or to any purchaser of the Project or a direct or indirect interest in Owner. Each Party agrees that only Personnel who need to have access to Confidential Information in order to perform their duties will be authorized to receive the same, and then only to the extent needed and provided such Personnel have been advised of the obligations and restrictions set forth in this Section 18.3. Each Party shall be responsible for any breach of this Agreement by its Personnel.

18.3.4 Notwithstanding the foregoing, information shall not be deemed to be Confidential Information where it:

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(a) Is or becomes public information or otherwise generally available to the public through no act of or failure to act by the receiving Party;

(b) Was, prior to the date of this Agreement, already in the possession of the receiving Party and was not received by such Party directly or indirectly from the other Party;

(c) Is rightfully received by the receiving Party from a third party who is not prohibited from disclosing it to such Party and is not breaching any agreement by disclosing it to such Party;

(d) Is independently developed by the receiving Party without benefit of Confidential Information received from the other Party;

(e) Is the property of the Party disclosing such information;

(f) Is necessary or advisable for FPL to exercise its Intellectual Property Rights under this Agreement; or

(g) Is necessary or advisable to disclose such information for the purpose of enforcing or exercising the disclosing Party's rights hereunder.

Specific information shall not be deemed to be within the foregoing exceptions merely because it is embraced by more general information within such exceptions, nor shall a combination of features be deemed to be within such exceptions merely because the individual features are within such exceptions.

18.3.5 If a Party is required by Applicable Law or any Government Authority to disclose any Confidential Information, such Party shall promptly notify the other Party of such requirement prior to disclosure so that the other Party may seek an appropriate protective order and/or waive compliance with the terms of this Section 18.3. If such protective order or other remedy is not obtained, then such Party shall furnish only that portion of the Confidential Information which is legally required to be furnished by the Applicable Law or Government Authority; provided, however, that prior to making any such disclosure, such Party will:

(a) Minimize the amount of Confidential Information to be provided consistent with the interests of the other Party; and

(b) Make every reasonable effort (which shall include participation by the other Party in discussions with the Government Authority involved) to secure confidential treatment of the Confidential Information to be provided.

If efforts to secure confidential treatment are not successful, the other Party shall have the prior right to revise such information in a manner consonant with its interests and the requirements of the Government Authority involved.

18.3.6 Each Party acknowledges that the other Party would not have an adequate remedy at law for money damages if the covenants contained in this Section 18.3 were breached and that any such breach would cause the other Party irreparable harm. Accordingly, each Party also agrees that in the event of any breach or threatened breach of this Section 18.3 by such Party or its Personnel, the other Party, in addition to any other remedies it may have at law or in equity, shall be entitled, without the requirement of posting a bond or other security, to equitable relief, including injunctive relief and specific performance.

18.3.7 All right and title to, and interest in, FPL's Confidential Information shall remain with FPL. Subject to Section 3.32, all Confidential Information obtained, developed or created by or for Contractor exclusively for the Project, including copies thereof, is the exclusive property of FPL whether delivered to FPL or not. No right or license is granted to Contractor or any third party respecting the use of Confidential Information owned by FPL by virtue of this Agreement, except to the extent required for Contractor's performance of its obligations hereunder. Except for that Confidential Information which FPL requires to construct, operate, and/or maintain the Project and its power generation facilities, which Confidential Information shall not be subject to any obligation of return by FPL, at any time upon written request by a disclosing Party, the other Party shall promptly return to the disclosing Party all its Confidential Information,

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including all copies thereof, and shall promptly purge all electronic copies of such Confidential Information; provided that the other Party shall be entitled to keep one (1) copy of such Confidential Information for its legal records. The return of Confidential Information to the disclosing Party, the purging of electronic copies of Confidential Information or the retention of a copy of Confidential Information for legal records shall not release a Party from its obligations hereunder with respect to such Confidential Information.

18.3.8 Contractor shall coordinate with FPL with respect to, and provide advance copies to FPL for review of, the text of any proposed announcement or publication that include any non-public information concerning the Work prior to the dissemination thereof to the public or to any Person other than Subcontractors, Vendors, the Financing Parties or advisors of Contractor, in each case, who agree to keep such information confidential. If FPL delivers written notice to Contractor rejecting any such proposed announcement or publication within two (2) Business Days after receiving such advance copies, Contractor shall not make such public announcement or publication; provided, however, that Contractor may disseminate or release such information in response to requirements of Government Authorities.

18.4 NOTICE

18.4.1 Whenever a provision of the Contract Documents requires or permits any consent, approval, notice, request, or demand from one Party to another, the consent approval, notice, request, or demand must be in writing and delivered in accordance with this Section in order to be effective. Any such consent approval, notice, request or demand shall be delivered and received if:

(a) Personally delivered or if delivered by telegram or courier service, when actually received by the Party to whom notice is sent;

(b) Delivered by telex or facsimile, on the first Business Day following the day transmitted (with confirmation of receipt);

(c) Delivered by mail (whether actually received or not), at the close of business on the third Business Day following the day when placed in the mail, postage prepaid, certified or registered, addressed to the appropriate Party,

In each case, at the address and/or facsimile numbers of such Party set forth below (or at such other address as such Party may designate by written notice to the other Party in accordance with this Section):

(i) If to Contractor:

SunPower Corporation, Systems
1414 Harbour Way South
Richmond, California 94804
Attention: President
Fax: (510) 540-0552

With a copy to:

Latham & Watkins LLP
Sears Tower, Suite 5800
233 S. Wacker Drive
Chicago, IL 60606
Attention: Mark P. Ramsey
Fax: (312) 993-9767

(ii) If to FPL:

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Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida
Attention: E. N. Scoville II
Director – Construction
Fax: (561) 694-3960

With a copy to:

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida
Attention: General Counsel
Fax: (561) 691-7305

18.4.2 Any Party may change its address, facsimile number or e-mail number for the purposes of this Agreement by giving notice thereof to the other Party in the manner provided herein.

18.5 WAIVER

No delay, failure or refusal on the part of any Party to exercise or enforce any right under the Contract Documents shall impair such right or be construed as a waiver of such right or any obligation of another Party, nor shall any single or partial exercise of any right hereunder preclude other or further exercise of any right. The failure of a Party to give notice to the other Parties of a breach of the Contract Documents shall not constitute a waiver thereof. Any waiver of any obligation or right hereunder shall not constitute a waiver of any other obligation or right, then existing or arising in the future. Each Party shall have the right to waive any of the terms and conditions of the Contract Documents that are for its benefit. To be effective, a waiver of any obligation or right must be in writing and signed by the Party waiving such obligation or right.

18.6 SEVERABILITY

If any provision of the Contract Documents is held to be illegal, invalid, or unenforceable under present or future laws, such provision shall be fully severable; the Contract Documents shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part of the Contract Documents; and the remaining provisions of the Contract Documents shall remain in full force and effect and shall not be affected by the illegal, invalid, or unenforceable provision or by its severance from the Contract Documents. Furthermore, in lieu of such illegal, invalid or unenforceable provision, there shall be added automatically as a part of the Contract Documents a provision as similar in its terms to such illegal, invalid or unenforceable provision as may be possible and be legal, valid and enforceable.

18.7 GOVERNING LAW

The Contract Documents, and the rights and obligations of the Parties under or pursuant to the Contract Documents, shall be interpreted and construed according to the substantive laws of the State of Florida (regardless of any other jurisdiction's choice of law rules).

18.8 ENTIRE AGREEMENT; AMENDMENTS

The Contract Documents contain the entire understanding of the Parties with respect to the subject matter hereof and supersede all prior agreements, arrangements, discussions and undertakings between the Parties (whether written or oral) with respect to the subject matter hereof. The Contract Documents may only be amended by written instrument signed by all the Parties.

18.9 EXPENSES AND FURTHER ASSURANCES

Each Party shall pay its own costs and expenses in relation to the negotiation, preparation, execution and carrying into effect of the Contract Documents. Each Party shall, from time to time on being requested to do so by, and at the cost and expense of, the other Party, do all such acts and/or execute and deliver all such

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instruments and assurances as are reasonably necessary for carrying out or giving full effect to the terms of the Contract Documents.

18.10 NO THIRD PARTY BENEFICIARY

Except with respect to the rights of the Financing Parties, permitted successors and assigns and as provided above and the rights of indemnitees under Article XVI, INDEMNIFICATION:

18.10.1 Nothing in the Contract Documents nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any Person that is not a Party;

18.10.2 No person that is not a Party shall have any rights or interest, direct or indirect, in the Contract Documents or the services to be provided hereunder; and

18.10.3 The Contract Documents are intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to the Contract Documents or the services to be provided hereunder.

18.11 OFFSET

Notwithstanding any other provision hereof, any and all amounts owing or to be paid by FPL to Contractor hereunder or otherwise, shall be subject to offset and reduction in an amount equal to any amounts that may be owing at any time by Contractor to FPL. Further, for the avoidance of doubt, with respect to any provision of this Agreement that allows FPL to offset, set-off or draw against the Letter of Credit any amount then owed to Contractor, FPL shall have the express right to include in the amount offset, set-off or drawn under the Letter of Credit all of the reasonable costs and expenses it incurs in connection with enforcing such provision (including attorneys' and other consultants' fees).

18.12 COUNTERPARTS

This Agreement may be executed in multiple counterparts, each of which shall be deemed an original, and all of which together shall constitute one and the same instrument.

18.13 LIMITATIONS OF LIABILITY

18.13.1 Contractor's maximum liability under this Agreement shall be limited to (x) prior to the Provisional Acceptance Date, one hundred percent (100%) of the Contract Price and (y) after the Provisional Acceptance Date, 25% of the Contract Price, less the amount of Liquidated Damages previously paid by Contractor; provided, however, that such limitation of liability shall not apply to (i) Contractor's indemnification obligations under the Agreement related to claims of third parties; (ii) costs incurred by Contractor (and in the event of Contractor default, FPL) in achieving Provisional Acceptance and Final Acceptance (including the amount of any reduction in the Contract Price in the event that Contractor makes the election provided for in Section 10.5.1(b)); or (iii) any loss or damage arising out of any tort (including negligence and strict liability) or connected with Contractor's fraud, willful misconduct or illegal or unlawful acts. Contractor's limitations of liability shall not be reduced by the amount of insurance proceeds available to Contractor. FPL's maximum liability under this Agreement shall be limited to one hundred percent (100%) of the Contract Price prior to the Provisional Acceptance Date and 25% of the Contract Price after the Provisional Acceptance Date, except with respect to any payment due and payable pursuant to Section 7.1,Contract Price; provided however, that such limitation of liability shall not apply to any loss or damage arising out of any tort (including negligence and strict liability) or connected with FPL's fraud, willful misconduct or illegal or unlawful acts. FPL's limitations of liability shall not be reduced by the amount of insurance proceeds available to FPL.

18.13.2 Except as expressly set forth in this Agreement, and notwithstanding anything else in this Agreement to the contrary, Contractor and FPL waive claims against each other for any indirect, special or consequential damages arising out of or relating to this Agreement. This mutual waiver includes:

18.13.3 Damages incurred by FPL for rental expenses, for losses of use, income, profit, financing, business and reputation, and for loss of management or employee productivity, or the services of such persons;

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18.13.4 Damages incurred by Contractor for principal office expenses, including the compensation of personnel stationed there, for loss of financing, business and reputation, and for loss of profit except anticipated profit arising directly from the work; and

18.13.5 This mutual waiver is applicable, without limitation, to all consequential damages due to either Party's termination in accordance with Article XV, TERMINATION.

The foregoing waiver shall not preclude or limit recovery (i) of Schedule Liquidated Damages, (ii) of damages payable by Contractor to FPL pursuant to Section 15.2.4, Amounts Due FPL, of Article XV, TERMINATION, (iii) of the Termination Payment; or (iv) under any indemnity or reimbursement obligation hereunder related to claims of third parties.

18.14 TIME IS OF THE ESSENCE

Contractor acknowledges that timely achievement by Contractor of Mechanical Completion, Provisional Acceptance and Final Acceptance by the applicable scheduled date therefore is essential to FPL, and therefore TIME IS OF THE ESSENCE in performing all of Contractor's obligations set forth herein.

18.15 RECORDS RETENTION

Contractor agrees to retain for a period of five (5) years from the Final Acceptance Date all records relating to its performance of the Work or Contractor's warranty obligations herein, and to cause all Subcontractors and Vendors engaged in connection with the Work or the performance by Contractor of its warranty obligations herein to retain for the same period all their records relating to the Work.

18.16 SUCCESSORS AND ASSIGNS

Subject to Section 18.1, ASSIGNMENT, this Agreement shall be binding on the Parties hereto and on their respective successors and assigns.

18.17 FINANCING PARTIES' REQUIREMENTS

Contractor acknowledges that FPL may borrow certain funds from the Financing Parties for the construction of the Plant and that, as a condition to making loans to FPL, the Financing Parties may from time to time require certain documents from, and agreements by, Contractor and its Subcontractors and Vendors. In connection therewith, Contractor agrees to furnish to the Financing Parties, and to cause its Subcontractors and Vendors to furnish to the Financing Parties, such written information, certificates, copies of invoices and receipts, lien waivers (upon payment), affidavits, consents to assignment of the Contract Documents and other like documents as the Financing Parties may reasonably request. In addition, Contractor agrees to accept all revisions or amendments to the Contract Documents which are reasonably requested by the Financing Parties in order to facilitate Financial Closing, provided that such revisions or amendments are of a nature typically obtained by financing parties in non-recourse financing. Upon the request of the Financing Parties, as a condition precedent to Financial Closing, Contractor shall state in writing whether or not it is satisfied with FPL's performance to that date.

18.18 FINANCIAL ASSURANCES

18.18.1 In the event that there is a default under Section 15.1.19, then, in addition to any other remedies that FPL may have under this Agreement or otherwise, FPL may inform Contractor of such determination and Contractor shall have ten (10) Business Days after receipt of notice of such determination from FPL to meet with FPL's senior management and provide assurance reasonably acceptable to FPL that Contractor is capable of performing and completing the Work and its obligations under the Contract Documents.

18.18.2 In the event such assurance is not acceptable to FPL, as determined by FPL in its sole discretion, Contractor shall immediately as requested by FPL:

(a) Require direct payment or co-payment to Subcontractors and any such payments or co-payments shall be credited against amounts due to Contractor under the Agreement;

(b) Adjust the amount of Work to be performed by Contractor and in good faith negotiate corresponding adjustments in the Contract Price and, if applicable, Critical Milestones; and/or

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(c) Assign to FPL any agreement or purchase order with a Subcontractor or Vendor, provided that:

(i) FPL shall assume the obligations under such agreement or purchase order accruing after the date of such assignment;

(ii) If requested by FPL, Contractor shall remain responsible for administering and managing such agreement or purchase order (including enforcing the warranty obligations thereunder);

(iii) In no event shall Contractor be relieved of its obligations under this Agreement, including its obligation to achieve Provisional Acceptance or Final Acceptance as a result of such assignment; and

(iv) If Contractor remains responsible for administering and managing agreements or purchase orders pursuant to subparagraph (ii) above, then in no event shall Contractor be entitled to an FPL Caused Delay, Force Majeure Event or other relief in connection with any matter or claim arising out of or in any way related to FPL exercising its rights pursuant to this Section 18.18.

18.19 WAIVER OF CLAIMS.

18.19.1 In the event that this Agreement is terminated by FPL in accordance with its terms, and FPL subsequently signs an agreement to complete the Work (or any portion thereof) with any Person, then Contractor shall and shall cause its Affiliates, including Contractor Parent Company, to waive the right to make any claims (other than claims by Contractor with respect to amounts specifically provided herein to be paid to Contractor in the event of a termination hereunder) against FPL or any Person with whom FPL negotiates or executes an agreement for completion of any portion of the Work based upon:

(a) Such termination;

(b) Any subsequent negotiations with any Person; and

(c) Execution of such agreement and performance thereunder.

Such waiver includes, without limitation, a waiver of any claims against FPL and any Person with whom FPL negotiates or executes an agreement for completion of any portion of the Work, for tortious interference with business relationships.

18.19.2 Contractor agrees to reimburse, indemnify, defend and hold FPL, the Financing Parties and their Affiliates and each of their respective directors, officers, employees, representatives, agents, advisors, consultants, counsel and assigns harmless from and against, on an After-Tax Basis, any and all losses, claims, obligations, demands, assessments, penalties, liabilities, costs, damages and expenses (including attorneys' fees and expenses) for any claim made by Contractor or any of the above entities pursuant to paragraphs (a), (b) or (c) of Section 18.19.1, above. Contractor expressly agrees that any Person with whom FPL negotiates or executes an agreement for completion of any portion of the Work is an express third party beneficiary of this Section.

18.20 ACCEPTANCE OR REJECTION IN BANKRUPTCY.

18.20.1 Notwithstanding anything contained in this Agreement to the contrary, if an order for relief under Chapter 11 of the Bankruptcy Code is entered with respect to Contractor during the term of the Agreement, then Contractor acknowledges and agrees that it will, subject to Bankruptcy Court approval, formally assume or reject, subject to the requirements of 11 U.S.C. §365, the Agreement within seven (7) days of delivery of written request for such action by FPL. If Contractor fails to timely move for approval or rejection of the Agreement, it acknowledges and agrees that:

(a) It will not contest or in any way otherwise take any action to oppose such a motion filed by FPL or the lifting of the automatic stay of 11 U.S.C§362 to permit FPL to enforce its rights under the Agreement (the "Lift Stay Order");

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(b) It waives all rights it may have under 11 U.S.C. §362(f);

(c) It hereby consents to the ex parte entry of the Lift Stay Order pursuant to 11 U.S.C. §362(f); and

(d) At the option of FPL, it hereby agrees that it will execute an agreed Lift Stay Order on forty-eight (48) hours' notice.

18.20.2 Contractor acknowledges and represents to FPL and agrees that:

(a) It is familiar with the Agreement and the importance of completing its obligations under the Agreement on time and in accordance with its terms; and

(b) Based upon such familiarity, it is critical to performance of its obligations under the Agreement that FPL have prompt and immediate access (in accordance with the requirements of this Agreement) to its contractual remedies under the Agreement in the event of a Contractor Event of Default.

18.21 CONTRACTOR'S LICENSE

Contractor hereby states and FPL acknowledges that Contractor does not presently hold a license as a qualified business entity under Fla. Stat. Chapter 489 (a "Florida Contractor's License"), but that an application for such qualification has been submitted to the Florida Department of Business and Professional Regulation for processing. FPL further acknowledges its full knowledge of Contractor's failure to have a Florida Contractor's License status and hereby agrees that FPL shall not challenge the enforceability of this Agreement based on Contractor's failure to have a Contractor's License as of the date of the execution of this Agreement. In order to satisfy the requirements of this Agreement, Contractor hereby covenants, warrants and agrees that it shall receive all proper licenses required to perform the work more particularly described herein prior to beginning physical work on the Project, including but not limited to a Florida Contractor's License.

ECRC-08-3312 HEARING EXHIBIT - 00000334

IN WITNESS WHEREOF the Parties have executed and delivered this Agreement as of the date first above written.

SUNPOWER CORPORATION, SYSTEMS		FLORIDA POWER & LIGHT COMPANY	
BY:	[signature]	BY:	[signature]
NAME:	HOWARD WENGER	NAME:	WILLIAM YEATON
TITLE:	EVP	TITLE:	VP T&C
DATE:	7/9/08	DATE:	7/9/08

Appendix A – Scope of Work

Appendix A
SCOPE OF WORK

ENGINEER, PROCURE AND CONSTRUCT
SPACECOAST SOLAR PV PROJECT

ECRC-08-3315
HEARING EXHIBIT - 00000337

Appendix A
SCOPE OF WORK

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ENGINEER, PROCURE AND CONSTRUCT
FPL PV PROJECTS

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Exhibit B.....Clean Fill Criteria

Exhibit C.....Site Boundary Limits

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Appendix A
SCOPE OF WORK

1.0 PROJECT DESCRIPTION

1.1 This project consists of the installation of the following ground mounted, fixed tilt, photovoltaic (PV) power generation system:

1.1.1 A 10 MW (net) photovoltaic power generation system at the National Aeronautics and Space Administration (NASA) John F. Kennedy Space Center (KSC), located near Titusville, Florida. This installation will be connected to FPL's distribution system.

1.1.2 The 10 MW (net) photovoltaic power generation system shall include the installation of 4 MW_{DC} of bifacial modules.

2.0 SCOPE OF WORK

2.1 Work by Contractor

2.1.1 The Work to be provided by Contractor shall include all work (except for those items specifically excluded) required to deliver a PV system ("Plant") capable of operating in accordance with the attached performance specifications, laws and permits, and in accordance with the project milestone schedule. Contractor's scope of work shall include, but shall not necessarily be limited to, the engineering, design, supply, delivery, installation, construction, training, start-up, and testing, as necessary to deliver the commercially operational Plant. Contractor shall design and construct the Project in accordance with this Appendix A, Scope of Work, and all of the Exhibits attached hereto. The following equipment, material and services shall be provided:

2.1.2 Structural systems as necessary to support photovoltaic panels, inverters, switchgear, circuit breakers, protective relaying equipment, control systems, transformers, enclosures, and other components.

2.1.3 Electric systems for all Plant services including power wiring, switchgear, duct banks, cable trays, conduit, circuit breakers, disconnect switches, inverters, instruments, transformers, protective relaying, lighting, and other components as required.

2.1.4 Instrumentation, controls, interconnecting control wiring, panels, cable tray and/or conduits required for the complete individual equipment and system controls.

2.1.5 Lighting fixtures, lighting panels, convenience receptacles, wiring, raceways and other components required for a complete lighting system, including site access and site area lighting.

2.1.6 Grounding rods and other components for a complete grounding system and lightning protection system.

2.1.7 A condition monitoring system for local and remote monitoring. Remote monitoring shall be capable of connecting to the Internet for web-enabled data monitoring.

2.1.8 AC kWh meter cabinets for FPL provided primary and backup revenue meters.

2.1.9 Site meteorological station(s) as required to obtain data to determine system performance.

2.1.10 All required equipment tests and inspections.

2.1.11 Engineering and technical support services for permits and licenses that require Contractor provided design and information. Contractor shall use best efforts in supplying support for all FPL licensing and approval requirements.

2.1.12 Site Security during construction and commissioning. Permanent site security system including perimeter fencing, and four (4) manual gates.

2.1.13 Construction consumables through Provisional Acceptance. Consumables will include but not be limited to chemicals, fuses, and other supplies. Contractor will also supply all necessary electrical power and water required for construction.

2.1.14 Delivery, unloading, and storage of all Contractor supplied equipment.

2.1.15 Operating tests to demonstrate guaranteed performance.

2.1.16 All calculations necessary for proper sizing of electrical and mechanical equipment and systems to insure safe and reliable plant operation under all plant operating modes.

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2.1.17 Contractor shall comply with all permit requirements. Contractor shall develop an environmental control program that incorporates all permit and Exhibit A (Environmental Rules for Contractors) requirements for the construction and startup activities at the Job Site.

2.1.18 Contractors shall have a safety program for the site that incorporates all OSHA and Appendix X (Safe and Secure Workplace Policy) requirements.

2.1.19 Temporary facilities for FPL's site staff during construction and commissioning. For bid purposes assume space is required for 4 people.

2.1.20 Installation of FPL provided metering transformers and the supply and installation of conduits from the metering transformers to the meter cabinet. FPL shall provide the revenue metering cables.

2.2 Work by FPL

2.2.1 FPL will provide a permitted, cleared, and level graded site.

2.2.1.1 Site development and preparation includes access roads, grubbing, clearing, site leveling, site landscaping and soil stabilization. The maximum change in elevation shall be 7% in any direction.

2.2.2 Utility grade AC kWh meters will be supplied and installed by FPL. Primary and backup meters will be provided.

2.2.3 FPL will prepare and submit the Small Generator Interconnection Request. The Interconnection Study will be provided to the Contractor within 30 days of the effective contract date.

2.3 Boundary and Interface Limits

2.3.1 All work provided by Contractor shall be within the site boundary limits.

2.3.1.1 The site boundary is detailed in Exhibit C (Site Boundary limit).

2.3.1.2 The site boundary existing conditions are detailed in Exhibit D (Site Development Plan).

2.3.1.2.1. Existing conditions shown are for informational use only and not for construction.

2.3.1.3 Contractor shall connect into, interface or terminate at the connection to 13.8 kV FPL distribution system, at the southeast corner of the site boundary.

2.3.1.4 The interface location to be the Contractor-provided switch cabinet from which the Plant output will leave the site boundary at distribution or transmission voltage. FPL to provide interconnection between the switch cabinet and FPL Courtenay Substation.

3.0 PLANT DESIGN CRITERIA

3.1 Site Location

3.1.1 The Plants will be situated at NASA's John F. Kennedy Space Center located near Titusville, Florida.

3.1.2 The plant location is 28.48°N, 80.68°W.

3.1.3 Design Data

3.1.3.1 Range of Ambient Conditions: The Plant shall be capable of continuous operation between the following extreme temperatures:

3.1.3.1.1. 103 °F maximum ambient temperature.

3.1.3.1.2. 19 °F minimum ambient temperature

3.1.3.2 Wind Load per Florida Building Code, 2004, effective July 1, 2005 as amended by Brevard County.

3.1.3.3 Seismic Load per Florida Building Code, 2004, effective July 1, 2005 as amended by Brevard County

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3.1.3.4 Precipitation:

3.1.3.4.1. Annual Average = 55.02"

3.1.3.4.2. Maximum Monthly Average = 7.87"

3.1.3.4.3. Minimum Monthly Average = 2.35"

3.1.3.4.4. One day maximum = 11.44"

3.1.3.5 Design Storm Events, 24 hour precipitation

3.1.3.5.1. 10 year (10% probability) – 8.0"

3.1.3.5.2. 25 year (4% probability) – 10.0"

3.1.3.5.3. 110 year (1% probability) – 12.0"

Note 1: For storm water detention, retention, and evaporation pond facilities unless specific state or local regulations are more stringent.

Note 2: For site drainage facilities unless specific state or local regulations are more stringent.

Note 3: For site drainage system without causing damage to major plant facilities.

3.1.3.6 Freeze Protection: Freeze protection shall be provided for and limited to all instrumentation and instrument sensing lines.

3.2 Operational Criteria

3.2.1 The Plant shall be designed for fully automatic, unmanned operation. This shall include startup, shutdown, abnormal operating condition (i.e. voltage, frequency excursions) detection and shutdown, data monitoring, etc.

3.3 Plant Performance

3.3.1 Contractor shall design and construct the Plant to produce the specified net electrical AC power of 10 MW, based on Standard Test Conditions.

3.3.2 Contractor shall provide a recommended spare parts list, including the proposed pricing for spare parts within 30 days of the Contract effective date.

3.3.3 The Plant shall be designed to maximize the annual energy production.

3.4 General Requirements

3.4.1 The systems and equipment supplied by Contractor shall be suitable for the environment in which they will be located and shall be designed for a Plant life of at least thirty (30) years.

3.4.2 The specifications provided herein are intended to identify overall system requirements and certain specific hardware requirements, which FPL requires to ensure that the Plant provided by Contractor shall operate reliably and safely during the Plant's design life, and that the Plant shall be able to be operated and maintained in a cost-effective manner. The adequacy of the overall system design to meet these requirements is the responsibility of Contractor.

3.4.3 The general system performance criteria are defined in this Technical Specification, the Exhibits and Appendix HH. Contractor is responsible for ensuring that all system performance criteria included in this specification are met by the final Plant design.

3.5 Reliability and Maintainability

3.5.1 The design philosophy used to attain high reliability and maintainability shall be consistent with industry standards including:

3.5.1.1 Design margins and de-rating factors in sizing equipment to account for wear, performance degradation, voltage drops, and other conditions. Performance guarantees, however, shall be based on the new and clean condition.

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3.5.1.2 Provisions to isolate and bypass equipment for repair where feasible without shutdown of the system of which it is a part, such as repairing a component with minimized need to shut down surrounding components.

3.5.1.3 Access provisions for maintenance of equipment items known to require frequent service, such as inverters. Stairs shall be provided to elevated locations when access is required on a daily or frequent basis.

3.5.1.4 Access and removal provisions for all equipment parts from Plant using conventional maintenance equipment.

3.5.1.5 Compliance with manufacturer requirements for pull space and recommendations for laydown/storage areas.

3.5.2 Contractor shall provide as part of the equipment operations and maintenance manual, the typical daily, monthly, and annual maintenance activities expected for the Plant. This shall include inspection and testing activities, preventative/periodic maintenance activities, and recommended equipment replacement intervals for the Plant.

3.6 Noise

3.6.1 The Plant shall meet all applicable Federal, State, and local noise requirements.

3.6.2 The near-field A-weighted sound pressure level resulting from each balance-of-plant individual equipment package shall not exceed a spatial average of 85 dBA at a distance of three (3) feet from the equipment face and five (5) feet above the ground and personnel platforms unless approved by FPL. Contractor shall evaluate near field noise level on an individual equipment basis as certain Plant equipment is inherently noisy and special noise control measures may be necessary to comply with the 85-dBA criteria. For certain equipment, these noise control measures are not practical for reasons of performance, cost, maintenance access, heat buildup, space limitations, safety, etc. Therefore, if it is not reasonable and feasible to meet the 85-dBA criteria, administrative controls shall be implemented. Administrative controls include posting warning signs, prescribing hearing protection, and limiting access to ensure worker noise exposure does not exceed a 90 dBA average over an eight (8) hour period. The intent of this requirement is to control occupational noise exposure levels, protect worker hearing, and improve working conditions. The noise levels must conform to Occupational Safety and Health Act and all applicable State and local requirements.

3.6.3 In the design and layout of equipment, Contractor shall endeavor to attain permissible noise exposure levels, without the use of hearing protection. In areas where this is not practical, as discussed in Section 3.7.2, above, Contractor shall conduct an in-plant noise survey to identify the in-plant areas that are exposed to A-weighted sound pressure levels exceeding 85 dBA. Contractor shall designate areas over 85 dBA as high noise level areas with signs in the Plant, and shall indicate boundaries on the as-built general arrangement drawings for the mandatory wearing of hearing protection.

3.7 Miscellaneous Technical Requirements

3.7.1.1 Long-term operability, maintainability and safe operation of the Plant is of primary concern to FPL. As a result, Contractor shall take prudent measures in the design to facilitate ease of operation and maintenance and provide adequate access to all equipment.

3.8 Codes, Regulations and Standards

3.8.1.1 Contractor shall design and construct the Plant in accordance with all federal, state and local laws and the codes, regulations and standards listed below. The codes and standards utilized shall be the latest editions in effect on the effective date of this Contract. Where these codes do not govern specific features of the equipment or system, Contractor and Original Equipment Manufacturer (OEM) standards shall be applied. Where local codes or ordinances will have an impact on the design (e.g. building height restrictions) FPL and Contractor shall jointly address these with the local authorities having jurisdiction.

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3.8.2 Federal Regulations

3.8.2.1 Federal Environmental Standards

3.8.2.1.1. US Environmental Protection Agency Regulations

A. Resource Conservation and Recovery Act Regulations

B. Clean Water Act

C. Clean Air Act

D. Oil Pollution Act

E. Comprehensive Environmental Response, Compensation and Liability Act

F. Emergency Planning and Right-to-Know Act

G. Toxic Substances Control Act

3.8.2.1.2. National Environmental Policy Act

3.8.2.1.3. US Fish and Wildlife Regulations (e.g. Endangered Species Act)

3.8.2.1.4. US Army Corps of Engineers Regulations

3.8.2.2 Occupational Safety and Health Act (OSHA)

3.8.2.2.1. 29 CFR 1910 Occupational Safety and Health Standards

3.8.2.2.2. 29 CFR 1926 Safety and Health Regulations for Construction

3.8.2.3 US Department of Transportation Regulations

3.8.2.4 Code of Federal Regulations

3.8.3 Applicable State, County and Local Codes and Regulations

3.8.3.1 Florida Department of Environmental Protection Regulations

3.8.3.2 Florida Water Management District Regulations

3.8.3.3 Florida Statutes, Chapter 373 (Water Resources)

3.8.3.4 Florida Fish and Wildlife Conservation Commission Regulations

3.8.3.5 Florida Department of Community Affairs Regulations

3.8.3.6 County Regulations

3.8.3.7 Florida Department of Transportation Regulations

3.8.3.8 Local Codes and Ordinances

3.8.4 Applicable Industry Codes and Standards from the following list. Alternative standards may be used only upon FPL's acceptance of Contractor's written request, which shall specify the proposed alternative standard, why such change is necessary and how compliance is to be achieved.

3.8.4.1 Mechanical

3.8.4.1.1. ANSI - American National Standards Institute,

3.8.4.1.2. PTC - Power Test Codes - Applicable Test Codes

3.8.4.1.3. ASNT - American Society for Nondestructive Testing

3.8.4.1.4. ASTM - American Society for Testing and Materials

3.8.4.1.5. AWS - American Welding Society

3.8.4.1.6. SSPC - Steel Structures Painting Council

3.8.4.1.7. MSS – Manufacturers Standardization Society

3.8.4.2 Electrical

3.8.4.2.1. ANSI - American National Standards Institute

3.8.4.2.2. FM - Factory Mutual

3.8.4.2.3. ICEA - Insulated Cable Engineers Association

3.8.4.2.4. IEEE - Institute of Electrical and Electronics Engineers

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3.8.4.2.5. IESNA - Illuminating Engineering Society of North America
3.8.4.2.6. ISA - International Society for Measurement and Control
3.8.4.2.7. LPC - Lightning Protection Code
3.8.4.2.8. NEC - National Electrical Code
3.8.4.2.9. NEMA - National Electrical Manufacturers Association
3.8.4.2.10. NESC - National Electrical Safety Code UL - Underwriters
3.8.4.2.11. UL Underwriters Laboratories
3.8.4.2.12. NFPA – National electric code (NEC)
3.8.4.2.13. EN – European Norms
3.8.4.2.14. IEC – International Electric Code

3.8.4.3 Civil/Structural/Architectural

3.8.4.3.1. ACI - American Concrete Institute
A. ACI 318 - Building Code Requirements for Reinforced Concrete
B. ACI Manual of Standard Practice
C. ACI 350R – Environmental Engineering Concrete Structures

3.8.4.3.2. ADA - Americans with Disabilities Act
3.8.4.3.3. AISC - American Institute of Steel Construction
3.8.4.3.4. AISI - American Iron and Steel Institute "Specification for Design of Cold-Formed Steel Structural Members," Parts 1 and 2
3.8.4.3.5. AWS - American Welding Society
3.8.4.3.6. FBC – Florida Building Code
3.8.4.3.7. SSPC - Steel Structures Painting Council

4.0 MECHANICAL SYSTEMS AND EQUIPMENT

4.1 General

4.1.1 Motors

4.1.1.1 General Purpose Induction Motors, 250 HP and below, shall meet NEMA (MG-1), NEC and the following standards and criteria:

4.1.1.1.1. Class F insulation/B temperature rise, Service Factor = 1.15.
4.1.1.1.2. Rated ambient forty degrees Centigrade (40°C).
4.1.1.1.3. TEFC Enclosure for outdoor applications, ODP Enclosure for indoor application.
4.1.1.1.4. Standard Efficiency.
4.1.1.1.5. Standard Balance Rotors or better.
4.1.1.1.6. Space heaters in all motors 25 HP and above (static motor winding heaters are not an acceptable alternate).

5.0 ELECTRICAL SYSTEMS AND EQUIPMENT

5.1 General Requirements

5.1.1 The Plant electrical systems shall be designed to supply power to auxiliary electrical equipment and systems.

5.1.2 Voltage insulation levels, equipment interrupting and continuous current capacities, circuit protection and mechanical strengths shall be selected and coordinated in accordance with calculations and the recommendations of IEEE, ICEA, NEMA and ANSI

5.1.3 Environmental Conditions

5.1.3.1 MV and LV switchgear, MV and LV MCC's, inverters, DC systems (battery and charger systems), DC and AC distribution panels may be located in pre-fabricated walk-in Power Distribution Centers (PDC's). PDC's shall be environmentally controlled to meet the electrical equipment ambient requirements.

5.1.3.2 Conduit and cable tray entry to outdoor enclosures, panels, switchgear, cabinets, etc. shall not be from the top. Bottom entry is preferred for rain protection. If bottom entry is not practical and side entry is required, entrances shall be installed with watertight fittings or FPL approved flashings.

5.1.3.3 Enclosures for all equipment shall be in accordance with NEMA Standards and type number and shall be suitable for their location as follows:

5.1.3.3.1. NEMA 1.... Indoors (General Purpose)

5.1.3.3.2. NEMA 3R. Outdoors and Indoors (in wet locations)

5.1.3.3.3. NEMA 4.... Outdoors and Indoors (in wet locations – dust tight)

5.1.3.3.4. NEMA 4X. Outdoors - Indoors in wet and corrosion resistant locations

5.1.3.3.5. NEMA 7.... Classified Areas, Class I, Div 1 Group D

5.1.3.3.6. NEMA 9.... Classified Areas, Class II, Div 1

5.1.3.3.7. NEMA 12.. Non-environmentally controlled indoor dusty areas

5.1.3.3.8. Enclosures containing non-arching devices (sealed contacts, terminals, etc.) may be NEMA 12 or 4X in Class I, Division 2 areas.

5.2 Raceway, and Miscellaneous Services

5.2.1 Conduit and Cable Tray

5.2.1.1 Underground conduits shall be schedule 40 PVC direct buried rated or concrete encased rated. Underground conduits may be directly buried in areas that do not require concrete encased duct banks for structural considerations. Use of buried cable is acceptable provided it meets applicable industry codes and standards.

5.2.1.2 Aboveground conduit shall generally be RGS. Aluminum, PVC schedule 80, or PVC-coated conduit may also be used in corrosive areas. Aboveground conduit shall be ¾ inch minimum except ½ inch conduit may be used to connect to instruments or devices with ½" nipples as required.

5.2.1.3 Connections to equipment requiring removal from service or subjected to vibration or movement shall be made with flexible conduit. Liquid tight flexible metal conduit and approved fittings shall be used for outdoor and indoor equipment.

5.2.2 Cable Tray

5.2.2.1 Cable tray shall be per NEMA VE-1.

5.2.2.2 All cable trays, excluding instrumentation trays, shall be provided with external ground wire bonded to the tray and connected to the Plant ground grid at a pre-determined spacing not to exceed 100 feet.

5.2.2.3 Cable trays shall be aluminum or galvanized steel ladder type with tray covers where mechanical protection is necessary. All signal circuits (for levels 1&2) carrying trays shall be galvanized steel or aluminum solid bottom or ventilated trough trays with tray covers

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5.3 Power and Instrument Cable

5.3.1 For 4160v, Medium voltage cable shall be rated 8kV, 90°C or 105°C, stranded copper conductor, shielded, EPR insulation (100% level), and an overall PVC, CPE or CSPE cable jacket. (Note: 5kV at 133% level may be used in lieu of 8kV).

5.3.2 For 6900v, Medium voltage cable shall be rated 8kV, 90°C or 105°C, stranded copper conductor, shielded, EPR insulation (133% level), and an overall PVC, CPE or CSPE cable jacket. (Note: 15kV at 100% insulation may be used in lieu of 8kV.)

5.3.3 Multi-conductor control and power cable shall be rated 600 volts, 90°C, stranded copper conductors, XLP or EPR insulation and an overall PVC, CPE or CSPE cable jacket.

5.3.4 Single conductor wire and cable shall be rated 600 V, 90°C for XLP and 90°C or 105°C for EPR insulation. Single conductor 600 V tray cable greater than #1/0 AWG shall have EPR insulation with a PVC, CPE or CSPE cable jacket. Non-jacketed FREP insulation with appropriate UL flame test may also be used for large single conductor cables.

5.3.5 Single pair instrument cable shall be rated 600 V, XLP or PVC insulation, twisted shielded pairs with drain wires and a PVC, CPE or CSPE cable jacket.

5.3.6 Multi-pair instrument cable shall be rated 600 V, XLP or PVC insulation, twisted shielded pairs with drain wires, overall shield, and a PVC, CPE or CSPE cable jacket.

5.3.7 All custom control panel wiring shall be insulated with 600 V NEC type SIS insulation and all panel wiring shall have wire numbers for identification. Vendor supplied control panels of a proven field design may provide their field proven cable insulation.

5.3.8 The allowable ampacity of power cables shall be in accordance with ICEA and NEC requirements.

5.3.9 Lighting and fixture cable shall be furnished with 600 volt insulation.

5.3.10 Cables shall meet IEEE 383 flame test requirements. All cables installed in cable tray shall be rated for such installation.

5.3.11 For 1000 v, Low voltage cable shall be rated 1kV, 90°C or 105°C, stranded copper conductor, EPR insulation (100% level), and an overall PVC, CPE or CSPE cable jacket.

5.4 Inverters

5.4.1 Inverters shall be utility grade and specifically designed for PV installations.

5.4.2 Inverters shall meet the following minimum standards:

5.4.2.1 UL 1741 - Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources. IEC 62103 or EN 50178 Standards for Inverters for use with 1000 volt DC systems. For 1000 volt DC systems, in the event of conflict, IEC Standards supersede UL Standards.

5.4.2.2 IEEE 929-2000 - Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

5.5 Transformers

5.5.1 Contractor shall design and furnish and install interconnecting transformer(s) that step-up the inverter output voltage to the FPL distribution systems nominal voltage. The interconnecting transformer(s) shall be designed to provide zero sequence current to a ground fault on the FPL feeder (i.e. the PV generation shall be interconnected to the distribution system via a grounded system according to the IEEE-1547 standard).

5.5.2 The Contractor shall provide the interconnecting circuit breaker on the high side of each of the interconnecting transformer(s). The circuit breaker shall be rated for the distribution system voltage and short circuit available current at each corresponding location.

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6.0 CIVIL AND STRUCTURAL FEATURES

6.1 Civil Design Basis

The design for new facilities will require new surveys and topographic information as required for the areas involved in the new construction. Contractor shall be responsible to collect regional and local information regarding regional and local geology and seismology. Contractor shall be responsible for all surveys that are required to determine the final site plans. Contractor shall also be responsible to perform geotechnical investigations as necessary to develop the final site plan.

6.1.1 Surface Surveys and Investigations

6.1.1.1 The position of any surface penetration of underground utilities (i.e., valve station, manhole) within the construction area shall be physically verified by Contractor as part of the site survey.

6.1.1.2 Contractor shall be solely responsible for furnishing all labor, materials, tools and equipment to perform all surveying work and provide all services necessary for, or incidental to construction of buildings, new utilities, and other new facilities; and to establish and maintain benchmarks, to make measurements to verify location of completed construction, and to survey alignment to existing property boundaries. Underground utilities, exclusion zones, and surface penetrations shall be identified on Contractors drawings.

6.1.2 Easement and Setbacks

6.1.2.1 Contractor shall observe all easements unless specific exceptions are obtained from FPL. Easements shall be identified on the Site Plan Drawings to be developed by Contractor. Minimum setback requirements shall be in accordance with local zoning codes and ordinances.

6.1.3 Contractor shall develop and provide analyses and detailed designs for dewatering systems.

6.2 Site Preparation

The Project design shall take into account existing site conditions with respect to soil characteristics and drainage. Contractor will be responsible for preparing, submitting and securing of all required construction-related permits. Contractor will also be required to prepare and submit any and all site compliance certifications regarding work completion to applicable agencies (e.g. as-built certification of storm water management system, if required).

6.2.1 Site Maintenance

6.2.1.1 All temporary access roadways used by Contractor shall be maintained in serviceable condition.

6.2.1.2 Excess and unsuitable soils will be disposed of on site.

6.2.1.3 Contractor shall be responsible for compliance with State and local requirements for fugitive dust emissions. Contractor shall prevent the spread of dust during its operations.

6.2.1.4 On-site open burning will not be permitted unless approved by appropriate local authorities and FPL.

6.2.2 Fill and Construction Drainage

6.2.2.1 Any fill that is brought onsite from any offsite location shall meet FPL's clean fill criteria (Exhibit B, Clean Fill Criteria). Testing of the fill at the offsite source shall be performed to assure that the fill meets these criteria.

6.2.2.2 Contractor shall be responsible for installing and maintaining adequate drainage and preventing soil erosion at the site during construction in accordance with State and local sediment and erosion control rules, regulations, and ordinances.

6.2.2.3 Final grade elevations shall be chosen to provide good foundation support for major structures and equipment, and minimize the disposal of excess

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materials. The foundation design will be based on the recommendations presented in the final geotechnical report.

6.2.3 Excavating, Filling and Backfilling

6.2.3.1 Contractor shall be responsible for furnishing all supervision, labor, tools, materials and equipment, performing all operations in connection with excavating of all materials (excluding pre-existing Hazardous Materials), obtaining fill and backfill materials, installing and compacting of fill and backfill materials and producing final grade lines across the Plant.

6.2.3.2 Contractor shall remove from the site all rubbish and debris found thereon, so as to prepare the site for excavation (Hazardous Materials are excluded).

6.2.3.3 Contractor shall take appropriate measures, including dewatering, to prevent the foundation and trenched areas from becoming unstabilized by the flow of water into the excavation or by cave-ins or slippage.

6.2.3.4 Slopes of excavated areas shall be protected from rutting and scouring. Surface water shall not be permitted to flow uncontrolled down any embankment slope.

6.2.3.5 In areas requiring vehicle access or crane placement, suitable subgrade shall be provided to sustain traffic loads.

6.2.3.6 Contractor's quality of work, including excavating, filling, backfilling, compacting, dewatering, subgrade preparation and stabilization, shoring and drainage shall comply with the geotechnical engineer's recommendations, the applicable American Society for Testing and Materials (ASTM) standards and any State and local standards.

6.2.3.7 Before backfilling, excavated areas to be backfilled shall be cleared of all extraneous materials.

6.2.4 Contractor shall recommend the finish grade material and ground cover to minimize future maintenance requirements.

6.2.5 Control of Water

6.2.5.1 Dewatering to remove groundwater, including any rainwater or surface runoff that enters excavations shall be managed in accordance with the Stormwater Pollution Prevention Plan, St. John's River Water Management District (SWFWMD), County and FDEP requirements.

6.2.6 Soil Erosion and Sediment Control

6.2.6.1 Contractor shall develop soil erosion and sediment control plans. Contractor shall obtain and conform to the local erosion and sediment control regulation.

6.2.6.2 Soil erosion and sediment controls shall generally consist of control of runoff, vegetative stabilization, and sediment traps. All slopes, drainage ditches and other exposed areas shall be stabilized by vegetation. Sediment traps such as hay bales or synthetic filter fabric (silt fence) shall be installed around catch basin inlets, culvert inlets and at the top and toe of slopes. Temporary sedimentation basins shall be provided during construction and converted to permanent basins. Contractor shall maintain erosion and sediment control systems throughout construction at the site and any soil disposal areas.

6.2.7 Drainage

6.2.7.1 Contractor shall develop and implement a temporary drainage system for the construction phase of the project. The drainage system shall comply with all federal, State and local regulations. Included shall be the necessary sedimentation and erosion control measures during both construction and permanent operational phases. The drainage system shall be designed to

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comply with the July, 2002, 40CFR112 Spill Prevention Countermeasures and Control rule changes published in the Federal Register.

6.2.7.2 Contact and non-contact surface runoff from the power block and associated facilities will be collected and routed to on-site stormwater ponds. Construction area runoff shall also be routed to on-site stormwater ponds.

6.2.7.3 All swales shall be erosion control protected by grass and, if required, with man made material or rip rap.

6.3 Foundations

6.3.1 Foundations shall be reinforced concrete designed to support loads imposed. Driven pier foundations are acceptable if design is based on applicable wind loading requirements and allowable bearing values for soil.

6.3.2 Type of foundations required and allowable bearing values for soil shall be confirmed or as recommended by the geotechnical engineer based on the existing subsurface conditions. Differential settlement of foundations due to cut and fill affects shall be calculated and considered in the foundation design. Foundations for heavy equipment are expected to be totally on cut or on fill. If necessary, lean concrete may be added to minimize differential settlements for foundations that are partially on cut and partially on fill. The following foundation design criteria shall be used:

6.3.2.1 Total settlement: 1-1/2 inches. Differential settlement: 0.3 percent slope between adjacent column support points.

6.3.2.2 Foundations shall be designed using static analysis techniques assuming rigid elements and linear soil pressure distribution such that the allowable settlement and bearing pressure criteria are not exceeded. The minimum factors of safety against overturning and sliding shall be 1.5 and 1.25, respectively.

6.4 Concrete

6.4.1 Reinforced concrete structures shall be designed and constructed in accordance with ACI 318, Building Code Requirements for Reinforced Concrete. Concrete work shall conform to the requirements of ACI 301, Specifications for Structural Concrete

6.4.2 Concrete production, proportioning and placing as well as the formwork, reinforcing, joints and embedded items, repair, curing and protection shall all be in accordance with the applicable ACI Standards and Specifications. All concrete mixes shall be approved by the responsible design engineer and submitted to FPL for review and comment prior to use.

6.4.3 Grout shall be pre-packaged non-shrinking grout requiring water only, suitable for the service. Proportioning, mixing, placing, temperature, surface preparation and curing shall be in accordance with manufacturer's requirements. Contractor shall provide the required quality assurance testing.

6.4.4 Reinforcing bars shall be deformed bars conforming to ASTM A615, Grade 60. Welded wire fabric shall conform to ASTM A185.

6.4.5 Cement shall be Portland cement conforming to ASTM C150, Type (as required by soil conditions).

6.4.6 Aggregates for normal weight concrete shall conform to ASTM C33.

6.5 Site Restoration

All site development areas disturbed during construction, including laydown, parking and temporary office trailers, etc. shall be restored and stabilized in accordance with post-construction stormwater drainage requirements as specified in the Permits.

6.6 Structural Design Basis

The structural design of buildings, structures and portions thereof shall be in accordance with the Florida Building Code, 2004 effective July 1, 2005, and as amended by Brevard County. Structural design loads shall be in accordance with the following:

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6.6.1 Wind Loads

Wind loads shall be in accordance with the Florida Building Code, 2004 effective July 1, 2005, and as amended by Brevard County.

6.6.2 Seismic Loads

Seismic loads and element design criteria shall be in accordance with the Florida Building Code, 2004, effective July 1, 2005, and as amended by Brevard County.

6.6.3 Hydrostatic Loads

Below grade structures shall be designed to resist water pressure, corrosion and uplift.

6.7 Steel Structures and Miscellaneous Steel

6.7.1 Steel structures for buildings and equipment support shall be designed, fabricated and erected in accordance with the AISC Specification for Structural Steel Building - Allowable Stress Design and Plastic Design, the Code of Standard Practice for Steel Buildings and Bridges, and the Manual of Steel Construction - Volume II – Connections, and the requirements of OSHA. Steel structures shall also conform to the applicable ASTM Standards, the AWS Codes and RCSC's "Specification for Structural Joints" using ASTM A325 or A490 bolts.

6.7.2 Contractor shall furnish and install steel access platforms, with ladders and galvanized stairs and grating in accordance with the requirements of the Occupational Safety and Health Administration requirements. Access shall be provided for normal operation and maintenance of Plant. Stair access shall be provided where practical with ladder access provided to other less frequently accessed components.

6.7.3 Materials for structural steel and miscellaneous steel shall conform to the requirements of the American Society for Testing and Materials "Standard Specification for Structural Steel" ASTM A36/ASTM A572 Grade 50/ASTM A992, and the requirements provided herein. Structural steel required for tube girts shall conform to ASTM A500, Grade B. All structural and miscellaneous steel shall be hot dip galvanized.

6.7.4 Structural steel checkered plate shall be two-way diagonal raised pattern floor plate. Checkered plate for exterior use shall be galvanized.

6.7.5 Open-web steel joists shall comply with the Steel Joist Institute "Standard Specification and Load Tables."

6.7.6 Metal decking shall comply with SDI "Design Manual for Floor Decks and Roof Decks."

6.7.7 Steel grating shall conform to ASTM A569 with minimum 3/16-inch wide by 1-1/4 inch deep bearing bars. Structural steel grating shall be welded and hot-dipped galvanized after fabrication in accordance with ASTM A123. Grating shall be banded at edges and openings with bars of the same size as the bearing bars. Grating for exterior use shall be serrated.

6.7.8 Ship ladders are not permitted unless approved by FPL.

6.7.9 Anchor bolts shall conform to ASTM A307, A36, or ASTM F1554 Grades 36, 55, and 105 with nuts conforming to ASTM A563, Grade A heavy hexagon. Anchor bolt sleeves shall conform to ASTM A501.

6.7.10 Expansion bolts shall be unfinished bolts in expansion shell anchors, or wedge bolt anchors. As an alternate Contractor can use drilled holes with anchors set in epoxy, if in accordance with equipment manufacturer requirements.

6.7.11 Anchor bolts shall be used for all structural and building columns, all major equipment, and all vibrating equipment.

6.7.12 Expansion bolts may be used for stairs, ladders, handrails, platform posts, and minor equipment. Expansion bolts shall not be used where the required bolt diameter is larger than 3/4 inch.

6.7.13 Steel pipe for handrail shall conform to ASTM A53, Type E or S, Grade B. Handrails for exterior use shall be galvanized.

6.7.14 Filler metal for welding shall conform to the requirements of AWS D1.1.

6.7.15 A member's end connection shall not have strength less than that provided by a full depth 3/8 inch thick clip angle.

6.7.16 Galvanizing, as specified herein, shall conform to the requirements of ASTM A123 or ASTM A153, as applicable.

6.7.17 Grating shall be welded bar grating, galvanized, banded and secured with clips. Metal decking shall be galvanized.

6.8 Painting

6.8.1 The Project scope shall include protective coating systems on all equipment and building materials except for stainless steel, insulated piping and concrete not exposed to a corrosive environment.

6.8.1.1 Hot-dip galvanized, in accordance with Applicable Industry Codes and Standards, is an acceptable protective coating.

6.9 Fencing

6.9.1 Site perimeter fence shall be 7 feet high and have an overall height of 8 feet from the bottom of the fabric to the top barbed wire. The fence shall have top rail, bottom tension wire, and three strands of barbed wire mounted on 45 degree extension arms. The upper strand shall be approximately 12 inches out from the fence and 12 inches above the top of the fabric. Posts shall be set in concrete as detailed.

6.9.2 Materials for site chain link fencing shall be as follows. All steel or malleable iron parts and accessories shall be hot-dip galvanized in accordance with ASTM A123 after fabrication.

6.9.2.1 Fabric - 9 gauge, 2 inch mesh; galvanized ASTM A392, Class 2; twisted selvage on top, knuckled selvage on bottom.

6.9.2.2 Posts - Steel pipe, ASTM F1083 standard weight (Schedule 40).

6.9.2.3 Line posts - 2-3/8 inch OD pipe, 3.65 lb per ft.

6.9.2.4 Terminal posts (end, corner, and pull) - 2-7/8 inch OD pipe, 5.79 lb per ft.

6.9.2.5 Gate posts (swing gates) - Gate or leaf 6 ft wide or less, 2-7/8 inch OD pipe, 5.79 lb per ft; gate or leaf over 6 ft wide and up to 13 ft, 4 inch OD pipe, 9.10 lb per ft; gate or leaf over 13 ft and up to 18 ft wide, 6-5/8 inch OD pipe, 18.97 lb per ft; gate or leaf over 18 ft wide, 8-5/8 inch OD pipe, 28.55 lb per ft.

6.9.2.6 Top Rail - 1-5/8 inch OD (Schedule 40) pipe, 2.27 lb per ft; or 1-5/8 by 1-1/4 inch roll formed sections weighing 1.35 lb per ft.

6.9.2.7 Post tops - Pressed steel, malleable iron with pressed steel extension arm, or one-piece aluminum casting with hole for top tension wire, designed to fit over the outside of the posts and to prevent entry of moisture into tubular posts.

6.9.2.8 Barbed wire Galvanized, ASTM A121 Class 3; two 12-1/2 gauge steel wires with 4 point round 14 gauge barbs spaced 5 inches apart.

6.9.2.9 Stretcher bars - Steel, 3/16 by 3/4 inch, or equivalent cross-sectional area.

6.9.2.10 Fabric ties - Aluminum bands or wires.

6.9.2.11 Gate frames - 1-7/8 inch OD (Schedule 40) pipe, 2.72 lb per ft; or 2 inch square, 4.32 lb per ft.

6.9.2.12 Tension wire - Galvanized coil spring wire, 6 gauge ASTM A641 Class 3.

6.9.2.13 Setting cement - Minwax "Super Por-Rok Cement" or Master Builders "Set 45."

6.9.3 Site gates shall be swing type, hinged to swing 180 degrees from closed to open, complete with frames, latches, stops, keepers, hinges, fabric, braces, pad-locks, and three strands of barbed wire. Gate leaves, except those on walk-through gates, shall have intermediate members and diagonal truss rods as required for rigid construction

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and shall be free from sag or twist. Gates shall be fitted with vertical extension arms or shall have frame end members extended to carry barbed wire. Joints between frame members shall be made by welding or by means of heavy fittings and shall be rigid and watertight. Truss rods shall be not less than 3/8 inch diameter. Gate fabric shall be same as fence fabric and shall be attached to frame ends by stretcher bars, bolt hooks, or other mechanical means.

6.9.3.1 Hinges shall be heavy pattern with large bearing surfaces and shall not twist or turn under the action of the gate.

6.9.3.2 Latches shall be plunger bar type, full gate height, and arranged to engage the gate stop, except single gates less than 10 feet wide may be provided with a forked latch. Latches shall be arranged for padlocking with the padlock accessible from both sides of the gate.

6.9.3.3 Stops shall consist of a roadway plate with anchor set in concrete and arranged to engage the plunger.

6.9.3.4 Keepers shall consist of mechanical devices for securing and supporting the free end of the gates when in the full open position. Keepers shall be mounted on 2-7/8 inch outside diameter pipe posts filled with concrete and set in concrete foundations.

6.9.3.5 Gates shall be installed so that they cannot be removed without disassembly of the hardware. Hardware attachment bolts shall be peened so that removal will be difficult.

6.9.4 The installed site fence shall conform to the alignment and finish grade indicated. Unless otherwise indicated or specified, all posts shall be plumb and spaced 10 feet apart. Where necessary, the fence grade shall be adjusted to fit the ground contour by slipping the fence fabric links.

6.9.5 Ground surface irregularities shall be graded as required to minimize changes in vertical alignment and to provide a smooth profile for the fence. Clearance below the bottom of the fence shall not exceed 2 inches.

6.9.6 The plan and profile of each reach of fence between corner posts, or between corner posts and gate posts, shall be straight. Ground surfaces shall be graded as required to achieve the straight profiles before each reach of fence is installed.

6.9.7 Top rail and bottom tension wire shall be installed before the fabric. To minimize raising the bottom of the fence to gain access, bottom tension wires shall be installed in the lowest position possible (approximately 6 inches above grade) and shall be attached to each post and securely anchored at terminal and gate posts. Straight runs between braced posts shall not exceed 1,500 feet. A terminal post shall be provided at each change in slope.

6.9.8 Fabric shall be attached to the top rail and bottom tension wire at 24 inch centers and to the line posts at 15 inch centers, all on the security side of the fence. Barbed wire shall be fastened to each extension arm by internal clips or external fabric ties. Stretcher bars shall be provided at each gate, terminal, and pull post. Each stretcher bar shall be threaded through the fabric and anchored to the post at 15 inch centers by positive mechanical means.

6.9.9 Each gate and terminal post shall be braced by a horizontal pipe brace and an adjustable truss extending to an adjacent line post. Corner posts located where the deflection angle is 10 degrees or greater shall be braced in both directions.

7.0 INSTRUMENT AND CONTROL SYSTEM

7.1 General

7.1.1 The Plant's instrument and control systems shall be designed to provide for the safe and efficient start-up, operation, shutdown and emergency shutdown of the Plant.

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7.2 Instrumentation General Design and Installation

7.2.1 All instruments and equipment shall be installed in a manner which assures reasonable protection against mechanical damage, wetting, or extremes of heat or cold. Instrumentation shall be stored in accordance with the manufacturer's recommendations until installation. Final locations and orientations must be selected for accessibility, repair, and calibration in place, easy access to the rear of the instruments (if needed), and for disconnection without resorting to cutting, burning, or welding.

7.3 Instrument Cabinets and Local Control Panels

7.3.1 Local Instrument Rack / Enclosure / Cabinet Installation

7.3.1.1 Instrument racks/enclosures/cabinets shall be secured to structural steel or to concrete. Racks/enclosures/cabinets shall be electrically grounded. Bolting to bare or galvanized metal shall be used for attaching a ground strap.

7.3.1.2 Prior to installation, Contractor shall ensure that instrument racks/enclosures/cabinets have sufficient clearances for the required blowdown piping and headers, door swing radius, etc., and that the racks/enclosures/cabinets are completely accessible for maintenance.

7.3.1.3 The racks/enclosures/cabinets shall be installed and anchored in place so that they are level and plumb and properly aligned in accordance with the above mounting requirements.

7.3.1.4 Racks/enclosures/cabinets shall not be supported by handrails. All instrument line penetrations into instrument enclosures/cabinets shall be through bulkhead fittings (couplings). Bulkhead couplings shall be supplied on instrument enclosures/cabinets for each instrument location. Top entry of instrument cabinets or instrument enclosures/cabinets junction boxes is prohibited. Bottom entry is the preferred method for conduits.

7.4 Local Instrument Cabinets / Racks

7.4.1 Instrument and Control Wiring and Instrument Cabinet Wiring

7.4.1.1 Both ends of conductor or wire pair shall be identified with a wire number or instrument tag number.

7.4.1.2 All necessary precautions shall be taken to maintain a high standard of cleanliness during storage and assembly. All metal chips, turnings, rust, dust, weld splatter, scale, and other particles shall be removed without destroying the continuity of the surface.

7.4.2 Marking

7.4.2.1 Contractor shall install stamped stainless steel tags for the following Contractor purchased equipment:

7.4.2.1.1. All instruments shall be tagged with the appropriate instrument tag number. Tags shall be secured with stainless steel wire with ends crimped together.

7.4.2.1.2. Each local instrument cabinet shall have a stainless steel tag permanently affixed to the cabinet front.

7.4.2.1.3. Each cabinet mounted instrument shall have a tag affixed to the instrument.

7.4.3 Continuous Monitoring System

7.4.3.1 Contractor shall provide a continuous monitoring system (Data Acquisition system – DAS) that is capable of providing real-time performance monitoring, historical data storage and retrieval, and Internet accessibility of data.

7.4.3.1.1. The monitoring system shall provide AC energy production on the individual inverter level.

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7.4.3.1.2. The monitoring system shall provide solar irradiance, ambient temperature and wind speed.

7.4.3.1.3. All monitored information is stored on the data logger as 15 minute averages and transmitted for processing, storage and backup. For added security, the DAS shall include a battery backup, so it can store up to four weeks of data.

8.0 PROJECT SPECIFIC CONSTRUCTION REQUIREMENTS

8.1 Lay down and Storage Requirements

8.2 Condition of Delivery of Equipment and Materials

8.2.1 In general, equipment and materials will be delivered to the site by truck. Contractor shall coordinate the ordering, delivery, and storage of all materials necessary for the performance of its Work, and Contractor shall be responsible for damage, loss, theft, casualty, shortages, shrinkage, and non-conformance of materials and equipment.

8.2.2 Truck deliveries and traffic shall comply with permit requirements.

8.3 Construction Support Facilities

8.3.1 Contractor shall provide all necessary temporary facilities at the site to support its staff and labor force and the delivery, unloading and storage of equipment and materials.

8.3.2 Contractor shall provide copies of drawings/specifications/ vendor manuals or other documents that FPL requires on-site during the project. Contractor shall also provide FPL personnel access to document control for specific information needs.

8.3.3 Any temporary storage facilities shall be capable of meeting any state, federal, or local requirements.

8.4 Construction Quality Control

8.4.1 First line, primary inspection and testing (hereafter referred to as Quality Control) are the responsibility of Contractor. Contractor's quality control procedures shall be clearly stated in the Quality Control Manual, and shall specify field inspections and inspection criteria. A summary of FPL's minimum requirements for Contractor's Inspection/Testing program is identified below. These minimum requirements are to be supplemented with additional requirements as determined by Contractor as specifications are developed and code requirements are identified. Problems discovered during inspections and testing which could impair job cost, schedule, or Plant function, will be immediately conveyed to FPL. Contractor's Quality Program must also include Contractor Quality Assurance.

8.4.2 Contractor shall conform to prevailing quality industry standards in accordance with Contractors profession in the location of the project. Any work which does not meet this standard of care shall be repaired, replaced, and re-performed at the sole expense of Contractor.

8.5 FPL's Scope of Services-Quality Assurance

8.5.1 FPL will perform an overview of the Quality Control function as practiced by Contractor. This overview does not include "Hold" or "Witness" points. Every effort will be made to implement a meaningful overview inspection without impeding Contractor's efforts or job progress. The overview is intended to assist Contractor in meeting design and code requirements, and to prevent deficient material/workmanship rather than to identify it after the fact. FPL's representatives will conduct the overview inspections. Concerns arising from the overview inspection will immediately be conveyed to Contractor for incorporation into Contractor's Quality Control Program for corrective action, recurrence control, and trending. FPL's representatives will continually monitor and evaluate Contractor's timeliness and adequacy of corrective actions and recurrence controls.

8.5.2 As a means of assuring that the performance of the Work fulfills the requirements of the Contract Documents, Contractor shall maintain a Quality Management Organization, which provides Quality Control/Quality Assurance expertise in a

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number of key areas. The program shall be capable of providing assurance that the receipt, storage, erection, installation, testing, and examination of all equipment, components, materials, and services will comply with the requirements of the Contract documents. The Quality Program shall be documented in a Quality Control Manual, which shall be submitted to FPL for approval 30 days after Notice to Proceed.

9.0 STARTUP AND COMMISSIONING REQUIREMENTS

9.1 General Requirements

9.1.1 Contractor shall provide FPL a Startup Execution Plan document that describes in detail all aspects of the Startup and Commissioning Program including how commissioning activities shall be incorporated into the design, procurement and construction of the Work. The Execution Plan shall be submitted to FPL for review and approval. FPL's approval shall not be unreasonably withheld.

9.2 Scope of Startup Program

9.2.1 Contractor shall supply all required labor to execute the startup plan and supply all test and calibration equipment, materials, and services necessary to perform all testing, system calibration, checkout, functional testing and initial operation as well as make adjustments, perform event and trip analysis to determine the root cause, and correct deficiencies, completely in accordance with this specification.

9.2.2 Construction Turn-over and Pre-commissioning

9.2.2.1 As the various subsystems, systems and equipment packages are brought to a state of mechanical completion by Contractor's construction organization they will one by one be turned over to Contractor's startup organization by means of a pre-commissioning procedure. Contractor will perform the non-operational adjustments, and checks to verify that each item of equipment, subsystem, package and system is ready for operational start-up and testing.

9.2.2.2 The following activities and verification steps are included:

9.2.2.2.1. Physical construction complete (a checklist shall be provided by Contractor).

9.2.2.2.2. Compile associated documentation for code compliance, QA/QC, design basis.

9.2.2.2.3. Complete post construction testing (i.e. cold alignment, bump motors for rotation, pressure test, bolt torque, electrical insulation, contact resistance for field assembled electrical connections, and continuity tests, etc.).

9.2.2.2.4. Complete cleanup, painting, insulation and/or punch-list items sufficiently to safely perform the startup testing and initial operation.

9.2.2.3 As the pre-commissioning for each individual item of major equipment, subsystem and major system is completed it will be documented with a turnover package demonstrating that it is ready for commissioning. The pre-commissioning package shall contain the procedures for executing the above activities, and documentation of their results. The package may be a subset of the Startup Turnover Package.

9.2.3 Start-Up Program Field Activities

9.2.3.1 During this phase Contractor will perform the calibration, testing and operation of the various portions of the Plant, starting with component tests, and then progressing through tests of subsystems and complete systems, and then operation of the Plant as a whole. The overall startup sequence and logic shall be developed by Contractor's Startup Manager so that subsystem startup packages are completed and presented to FPL's Operations Department in proper sequence to support an orderly startup. Coordination of Startup Activities shall include the following:

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9.2.3.2 From commencement of startup activities, Contractor's startup personnel, under the direction of Contractor's Startup Manager, will directly coordinate all such activities for energization and operation of equipment and systems being started up.

9.2.3.3 Contractor's Startup Manager will initially hold weekly and later, daily startup coordination meetings. Contractor's Startup Manager and FPL will mutually agree on the frequency of the meetings. All subcontractors performing work in areas currently being readied for subsystem turnover for operation shall attend, as well as Contractor's Construction Superintendent, appropriate manufacturer's technical representatives, and FPL's representative. The meeting shall include a review of activities since the last meeting and a look ahead at activities planned for the next two weeks.

9.2.3.4 Contractor shall maintain a single integrated punch-list of outstanding activities for the construction, commissioning, startup, and initial operation of the project. FPL shall have the authority to add or delete items from the punch-list.

9.2.3.5 FPL may elect to witness any or all pre-commissioning or startup activities. The coordination meeting shall serve as the mechanism for notifying FPL of when activities are taking place.

9.2.3.6 Contractor shall provide written procedures for use by Contractor's commissioning team and FPL's plant operating staff for all Commissioning Procedures.

9.3 Operating Mode, Capability Verification and Guaranteed Performance Tests

9.3.1 The Plant shall successfully complete the Operating Mode Tests, the Capability Verification Tests and the Guaranteed Performance Tests in accordance with Appendix HH(Performance Testing), to demonstrate compliance with the Agreement requirements for Minimum Performance Levels and Guaranteed Performance Levels.

9.3.1.1 Operating Mode Tests – Test(s) that demonstrate the capability of the Plant to operate automatically from morning startup, through the day, and evening shutdown. Test should also demonstrate the capability of the Plant to automatically operate in response to abnormal operating conditions, such as the failure of an inverter, distribution system disturbances, etc.

9.3.1.2 Capability Verification Tests – Test(s) that demonstrate the capability of the Plant to operate automatically, safely, and reliably over the full range of capacity, from startup to full capacity.

9.3.1.3 Guaranteed Performance Tests – Test(s) that demonstrate the guaranteed capacity of the plant.

9.3.2 Contractor shall provide the Plant performance test procedures that will demonstrate the Plant meets the required performance specifications.

9.3.3 Contractor shall be required to provide to FPL, for review and acceptance, detailed documents for these tests (test procedures) which will include but not be limited to:

9.3.3.1 Description of the test

9.3.3.2 List of all data to be collected

9.3.3.3 Instrumentation and location for taking all data points

9.3.3.4 Correction curves

9.3.3.5 Instrument and test accuracy's

9.3.3.6 Sample calculations

9.3.4 The draft Test documents shall be submitted for review at least 120 days before the expected test date. FPL shall provide comments within thirty (30) Business Days. Contractor will provide written response to FPL's comments within 10 Business Days and make necessary modifications to the test procedures.

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9.4 Environmental Control Program

9.4.1 Contractor shall develop and maintain an Environmental Control Program document to assure that all construction and start-up activities associated with the Project conform to best environmental practices, federal, state and local regulations, applicable permit conditions, conditions of certification, Environmental Rules for Contractors, and any other construction and start-up constraints identified in the Project's environmental permitting process. A secondary purpose of the Environmental Control Program is to provide the basis for emergency response programs that will be in place during construction and operation of the Project. The Program shall include an Environmental Control Plan and all other relevant program documents (i.e., permit matrices, storm water pollution prevention plan, spill prevention, control and countermeasure plan, emergency response plan, copies of permits, etc). The Environmental Control Program document will provide all relevant references for the project's environmental management.

9.4.2 The Environmental Control Program shall include an Environmental Control Plan that describes the processes that will be followed in order to comply with applicable Laws and permits. The plan assigns specific responsibilities for compliance with environmental restrictions and response to emergency situations during construction and startup of Project facilities.

9.4.3 The Environmental Control Program document shall also include a matrix of permit compliance activities, due dates, responsible person and current status. Copies of Contractor's and FPL's environmental permits applicable to the Project shall be included in the document.

9.4.4 The Environmental Control Program document shall be submitted to FPL for review and approval no later than 30 days prior to site mobilization.

9.5 FPL Notification

9.5.1.1 In the event Contractor becomes aware of any imminent conditions of non-compliance or receives either a Letter of Non-Compliance or Notice of Violation, Contractor shall immediately contact FPL and initiate appropriate measures to correct the non-complying condition or activity and prevent its recurrence.

9.6 FPL Audits

9.6.1.1 FPL shall reserve the right to conduct periodic quality control/quality assurance assessments and environmental audits of Contractor's project activities. Assessment and Audit findings in non-compliance with project permit requirements shall be immediately corrected by Contractor.

10.0 PROCUREMENT

10.1 Selection of Equipment Suppliers

10.1.1 Contractor shall procure equipment in accordance with the requirements of the Agreement from reputable suppliers who normally produce the type of equipment specified for use in heavy industrial applications.

10.1.2 Where specific requirements for equipment are included herein, Contractor shall ensure that these requirements are included in Contractor's specifications and complied with by the selected manufacturer. Contractor shall be responsible for proposing resolutions to any exceptions taken by suppliers to the requirements outlined herein and obtaining FPL's concurrence with these resolutions prior to accepting the exceptions.

10.1.3 FPL's review of these exceptions will be limited to ensuring compliance with the intent of these specifications, specifically to establish a minimum level of quality and functionality. FPL's concurrence or comments will be forwarded to Contractor within ten (10) Business Days of the date they are received in FPL's offices.

10.1.4 For other equipment, manufacturers and model numbers listed in this Technical Specification are representative only of the quality of equipment proposed.

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Manufacturers and model numbers of equal quality may be substituted for those listed in this Technical Specification.

10.1.5 Contractor shall have the obligation of ordering, receiving delivery of, storing, caring for, and installing such equipment and materials. Contractor shall coordinate the ordering, delivery, and storage of all materials necessary for the performance of its Work, and Contractor shall be responsible for damage, loss, theft, casualty, shortages, shrinkage, and non-conformance of materials and equipment.

10.1.6 No substitutions shall be made in the Work unless permitted in the Agreement and only then upon Contractor receiving prior written approval.

10.2 Vendor Inspection

10.2.1.1 FPL reserves the right to participate in scheduled vendor inspections of any equipment supplied under the terms of this Contract in accordance with the terms of the Contract. Contractor shall submit to FPL, prior to use, a listing of planned inspections for the major equipment to be supplied.

10.3 Material and Equipment Quality Control

10.3.1.1 Contractor shall provide new equipment, materials, and workmanship suitable for this application.

10.4 Inspection and Shop Testing

10.4.1 Contractor shall provide for shop inspection and testing of major equipment as determined by Contractor. Testing programs shall be established by Contractor, but shall not be less thorough than the manufacturer's standard testing procedures. Contractor is responsible for insuring that the manufacturers conform to the manufacturing specifications for quality, inspections and testing contained in all equipment contracts.

10.4.2 FPL reserves the right of shop inspection visits and may witness shop tests in accordance with the terms of the Agreement. Shop inspections by FPL do not relieve Contractor of responsibility contained in the Agreement. Contractor shall endeavor to notify FPL of the tests at least 5 Business Days in advance of tests.

10.4.3 Contractor shall submit certified copies of test reports and shop tests, to FPL.

11.0 PROJECT ADMINISTRATION

11.1 Project Meetings

11.1.1 During all active phases of the Project, Contractor shall be required to participate in a monthly Project Review Meeting with FPL. During the engineering, design, and procurement phases of the Project, this meeting will normally be held in Contractor's home office. Each of Contractor's lead discipline engineers will be required to update FPL's organization on the discipline progress to date, review design activities currently in progress, and discuss problem areas and the plan developed by Contractor to address and resolve them. After the start of construction, the monthly Project Review Meetings will normally be held in Contractor's site office and will be attended by Contractor's Project Manager, Project Engineering Manager, Home Office Construction Manager, Site Construction Manager, Startup Manager, and Project Controls Engineer. Update responsibilities and activities will correspond to those identified for the pre-construction phases of the project in the preceding paragraph.

11.1.2 In addition to the monthly meetings, Contractor shall submit a monthly progress report which includes schedules, detailing progress against the Level 2 CPM schedule, percent complete curves for the engineering and construction phases of the project, bulk commodity installation progress curves, and a discussion of problem areas and proposed resolutions. Attached to this report, Contractor shall provide current revisions of the purchase order, contractor drawing, and vendor drawing lists.

11.1.3 Between Project Review Meetings, Contractor shall conduct weekly construction/startup review meeting with all key site personnel in attendance. FPL's Representatives may attend these meetings.

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11.2 Document Preparation Requirements

11.2.1 Contractor shall produce all engineering documentation normally required for a project of this type, including, but not limited to, flexibility and expandability requirements, design objectives and constraints design studies and analyses, design calculations, equipment specifications and detailed design drawings.

11.2.2 The design documents shall be certified and approved by a licensed professional engineer and architect, and such other certified professionals as required by Law. Prior to Final Acceptance, Contractor shall turn over to FPL copies of all engineering documentation.

11.3 Project Submittals

11.3.1 Contractor shall supply the following drawings and information to FPL as part of the scope of Work. Items marked with an asterisk (*) shall be submitted for FPL's review. The transmittal of documents for FPL's review shall be by letter referencing that the documents are submitted per this Section of the Contract. Any comments from FPL shall be returned within ten (10) Business Days. As-builts shall be provided for the site plan, array layout and shading drawings, underground electrical drawings, electrical wiring and control wiring diagrams

11.3.1.1 *Site Plan

11.3.1.2 *Array Layout and shading diagrams

11.3.1.3 *Underground electrical drawings

11.3.1.4 *Erosion and Sedimentation Control Plans

11.3.1.5 *Dewatering Plans

11.3.1.6 *Electrical diagrams

11.3.1.7 *Array wiring diagrams

11.3.1.8 *Structural drawings

11.3.1.9 *Finish Grading and Paving drawing

11.3.1.10 *QA/QC Manual (Project Execution Plan and Project Coordination Procedure Manual)

11.3.1.11 Calculations substantiating any portion of the design, that is normally provided on request by FPL.

11.3.1.12 Drawings and Operating & Maintenance manuals for all equipment provided in Contractor's scope of work.

11.3.1.13 *Performance Test Procedures in accordance with 9.3.5.

11.3.2 All vendor drawings shall be sent to FPL in electronic format. Each vendor drawing shall be sent with a unique file number.

11.3.3 Contractor shall prepare and provide (including routine updates) to FPL, all typical lists including, but not limited to, the following:

11.3.3.1 Spare parts and special tools lists

11.3.3.2 Electrical Load List (Motors, Heaters, etc.)

11.3.3.3 Equipment List/Instrument List

11.3.3.4 Overall Plant Control Scheme

11.3.3.5 Instrument Data Sheets

11.3.3.6 Cable and Conduit Schedule

11.3.4 At the conclusion of the project and prior to Final Acceptance, Contractor shall supply to FPL a set of compact discs (CD's) containing final revision of the drawings and documents listed above.

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12.0 INTERCONNECTION PROTECTION AND METERING EQUIPMENT

12.1 Protective Relay Systems

12.1.1 FPL shall provide the PV plant generation interconnection protective relay systems for the Project. The protective relay panels will be installed by the Contractor. The interconnection protection will include a fiber optic communication system. This protective relay equipment will be installed in the by the Contractor.

12.2 Interfaces

12.2.1 Interfaces between the PV plant switchgear and other plant electrical systems, and the FPL interconnecting protective relay equipment will be provided by the Contractor.

12.3 Cable

12.3.1 Cable and conduit runs between the PV generating facility equipment and the interconnection protective relay equipment will be provided and installed by the Contractor.

12.4 Revenue Meters

12.4.1 The revenue meter will be provided and installed by FPL. The revenue metering transformers will be provided by FPL and will be installed by the Contractor on structures designed and installed by the Contractor. The conduit runs from the metering transformers to the meter cabinets will be provided by the Contractor. FPL will provide the metering cables to be installed by the Contractor. The metering transformers will be provided and installed by the Contractor. The transformers may be installed in the LV equipment provided by the Contractor. The location of the metering transformers shall be reviewed and approved by FPL. Conduit runs between the metering transformers and the metering cabinet shall be provided by the Contractor. The metering cables will be provided by FPL.

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Appendix A – Scope of Work
Exhibit A – Environmental Rules for Contractors

APPENDIX A
EXHIBIT A
ENVIRONMENTAL RULES FOR CONTRACTORS

1. This document must be made a part of all contracts and subcontracts by the EPC contractor for work to be performed on the Project site.

2. All contractors and subcontractors must review site orientation documents and sign affidavit if required by FPL Project Construction Manager (PCM). All contractors must implement an Environmental Control Program, reviewed and approved by FPL, as specified in the Scope of Work documents.

3. All contractors and subcontractors must inform the FPL Project Construction Manager (or designee) in writing of the type and amount of any chemicals (prior to their delivery to the site) to be brought on-site to complete the work. All contractors and subcontractors shall further notify the FPL PCM in writing during the course of construction, if any additional chemicals are to be brought on site.

4. All contractors and subcontractors must provide Material Safety Data Sheets (MSDS's) for all chemicals as directed by the FPL PCM prior to chemicals being brought on-site. Per the OSHA Hazard Communications standard, MSDS's must be maintained (by all contractors and subcontractors) on-site for any chemicals that could pose a health or physical threat to personnel, and all personnel must be Hazard Communication trained. The FPL PCM is responsible for ensuring that required Hazard Communication training is provided to FPL employees potentially exposed to these chemicals. Contractors are responsible for training their personnel.

5. No hazardous materials may be brought onto the Project site unless necessary for contracted work. Arsenic free bentonite shall be used for all drilling.

6. Waste management, including determination of the type of waste, quantity, and appropriate storage prior to off-site disposal, must be coordinated with the FPL PCM.
   - All contractors and subcontractors must provide FPL PCM with waste minimization plans. [Plans often include product substitution, process changes to eliminate or reduce chemical use, and/or recycling or reusing materials;]
   - Copies of any analyses performed to classify wastes as hazardous or non-hazardous must be given to FPL PCM and copied to FPL Environmental Services;
   - Hazardous materials used and hazardous waste generated must be stored in temporary or permanent secondary containment in areas agreed to by FPL PCM;
   - Secondary containment structures shall be maintained free from stormwater or other materials that defeat the purpose of the secondary containment. Stormwater or other materials removed from secondary containment structures must be managed appropriately.
   - All wastes must be stored in designated hazardous and non-hazardous containers appropriately labeled prior to proper disposal.
   - All original manifests, shipping papers, certificates of disposal, or other documents associated with waste transport and disposal must be provided to FPL PCM. Waste manifests must be signed by FPL contractor or subcontractor whose EPA ID number is used for waste disposal (unless otherwise specified – e.g., FDEP may required use of Substation's EPA ID number for contiguous project operations. In this case strict waste minimization and management is required in order to prevent changing current waste generation status of Substation).
   - All contractors and subcontractors must inform FPL PCM of all disposal sites to be used for hazardous and non-hazardous wastes prior to contract award;
   - All contractor and subcontractor employees responsible for managing hazardous wastes must be properly trained. Documentation of that training is to be provided to the FPL PCM and to FPL Environmental Services.
   - Hazardous materials releases or spills of any kind must be reported immediately to the FPL PCM (see Item 7); and
   - Contractor must consult with FPL PCM to determine if hazardous waste identification number should be obtained prior to contract award.

7. All contractors and subcontractors must coordinate with FPL PCM for proper storage of flammable or other types of chemicals.

8. All contractors and subcontractors are responsible for knowing and complying with all local, state and federal reporting and response requirements for releases or spills of oil, petroleum products, onsite products and

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chemicals, hazardous materials or hazardous wastes. All contractors and subcontractors must ensure that spill prevention measures are in place during the course of work at the Project site. This includes:

- Ensuring that all containers are closed at the end of each work day;
- Use of temporary hoses is carefully planned;
- Secondary containment is used for work near drains;
- All fuel and oil tanks used by all contractors and subcontractors must be placed in temporary secondary containment on an impervious surface;
- All contractors and subcontractors must maintain appropriate spill clean-up equipment near tanks and equipment that have potential for leaks;
- Following work and prior to start up, all contractors and subcontractors must ensure that all valves, manways, and pipelines are closed if appropriate to minimize risk of spills;
- All contractors and subcontractors must assume that all "out-of-service" lines will leak when brought back into service – appropriate spill containment measures must be taken;
- All contractors and subcontractors must document the training of personnel in spill awareness, notification (internal FPL/Agencies), and identification of spill risk areas; and
- All contractors and subcontractors must review the site's spill plans and know appropriate FPL site contact in the case of **ANY** spill. All contractors and subcontractors must coordinate with FPL PCM in order to understand the plant's spill response plans.

9. All contractors and subcontractors must comply with all applicable local, state, and federal laws in the course of performing work at the Project site. All contractors and subcontractors must coordinate with FPL PCM to ensure that the terms of permits and conditions of site certification to conduct work are met. Copies of any and all permits acquired by all contractors and subcontractors shall be provided to the FPL PCM. All contractors and subcontractors must coordinate any contact with regulatory agencies with the identified FPL contact.

10. All contractors and subcontractors must include environmental issues in daily safety tailgate sessions. FPL PCM should attend meetings when possible.

11. If work is conducted on Risk Management Plan (RMP) or Process Safety Management (PSM) regulated system, all requirements in the RMP and PSM documents must be reviewed/coordinated with the designated FPL contact and addressed during the course of work.

12. All contractors and subcontractors are required to maintain "good housekeeping" during the course of the project and must perform a thorough site clean-up following completion of the work. All unused products / chemicals are the property of the contractor and must be removed from the site at the end of the job unless specific arrangements are made with the PCM. All contractors and subcontractors must inform the FPL PCM when chemicals have been removed from the site.

13. All contractors and subcontractors must conduct a post-project site "walk-down" with the FPL PCM and plant environmental specialist to ensure that environmental issues are addressed and resolved.

14. All required erosion control/stormwater pollution prevention practices must be implemented and documented as required by regulations, Stormwater Pollution Prevention (SWPP) Plans or Best Management Practices (BMP) Plans. A listing of these requirements shall be coordinated with FPL PCM. Contractor is responsible for development and implementation of such plans. Conditions of Certification and / or all other applicable permit conditions must be strictly observed.

15. Threatened and endangered species are not expected to be present either in or near the Project area. Federal, state and local rules and regulations are designed to protect these species from harassment and harm. If threatened and endangered are observed on or near the site, the contractor and subcontractors are obligated to comply with these rules and regulations.

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EXHIBIT A
APPENDIX A
ENVIRONMENTAL RULES FOR CONTRACTORS
(continued)

ENVIRONMENTAL FIELD INSPECTION FORM

FACILITY: _____ **DATE:** _____

Instructions:

Walk site *at least once a week* and review each of the following areas

Explain each "No" answer in the comment section

Sign completed form and provide to FPL Project Manager with copy to FPL Environmental Services

General Environmental Management		**YES**	**NO**
1	Is housekeeping in all areas in good condition? All areas should be neat, orderly, and clean.		
2	Is the site free of any dead animals?		
3	Are spill cleanup materials and equipment in good condition and in close proximity to where they might be needed?		
4	Does security appear adequate? Fencing, locks, and lighting are in good condition.		
5	Are all contractors and subcontractors following the FPL Environmental Rules for Contractors? Has the Environmental Control Plan been implemented effectively?		

Waste Management		**YES**	**NO**
6	Is sandblast or bead blast material swept up? All material should be swept and contained for proper disposal. **Note that blast material containing metals could be hazardous waste; appropriate testing and documentation must be performed.*		
7	Are trash receptacles free of the following hazardous, universal, or recyclable waste? • Aerosol cans • Containers with product (e.g. paint, solvent) • Saturated oily rags or absorbent pads (SC – any oily rag/wiper prohibited) • Rags or absorbent pads with solvent odor • Discarded equipment that contains refrigerant • Recyclable items (aluminum cans, metal, cardboard, paper, etc.) • Universal waste (mercury containing lamps, batteries, pesticides, thermostats) • Tires		

ENVIRONMENTAL FIELD INSPECTION FORM

		YES	NO
8	Is waste properly contained in drums? • Bungs closed and no open funnels • Lids sealed tight • Clearly labeled with contents • Where contents are flammable, drum is grounded • Drums not stacked • Outside of drum clean; no evidence of waste product		
9	Are drums in good condition (includes empty drums)? • Free of dents • Free of holes • Free of rust • Free of bulges or leaks		
10	Is hazardous waste secondary containment in good condition? • Free of cracks, gaps, waste product, and no breaching • Containment drains closed		
11	Is hazardous waste secondary containment free of product or water?		
12	Is the emergency equipment in the hazardous waste storage area in working order? • Telephone or paging system must work properly • There must be a fire extinguisher present that is inspected monthly • Spill clean-up equipment must be present and in good condition • *If the facility is a small quantity generator, emergency response information must be posted near the communication system.*		
13	Will the isles in the Hazardous Waste Satellite and Accumulation (storage) areas allow for movement of emergency response equipment? • Must be able to see all sides of drum for markings and drum conditions.		
14	Is the accumulation start date on all drums in hazardous waste storage for disposal area?		
15	Are used oil drums and tanks properly marked with the words "Used Oil"?		
16	Are used batteries and mercury containing lamps stored in their designated area?		
17	Are used batteries and mercury containing lamps marked with accumulation start date?		
18	Are crushed or broken mercury containing lamps contained to prevent release of mercury?		
19	Are leaking batteries contained to prevent release of acid?		

EXHIBIT A
APPENDIX A
ENVIRONMENTAL RULES FOR CONTRACTORS
(continued)

ENVIRONMENTAL FIELD INSPECTION FORM

Chemical/New Product Management	**YES**	**NO**
20 Are new products properly stored in labeled containers? • Labeled with contents and appropriate hazard warnings • Containers kept closed • No open top buckets/pails with product • The original manufacturers label intact and readable • MSDS available onsite		
21 Are flammable liquids and aerosols stored in flammable cabinets?		
22 Is the quantity of gasoline storage inside a building < 25 gallons?		
23 Are the "No Smoking" areas free from any evidence of smoking?		
24 Are hazardous materials properly stored away from storm drains or pervious surfaces?		
25 Are storm drains free of hazardous materials? • No staining, discoloration • No odors • No visible sheen		

Air Emissions Management	**YES**	**NO**
26 Is the facility area free from any evidence of particulate fallout from stack emissions?		
27 Are fugitive emissions minimized and area sources minimized? (Sandblast curtains, slow vehicle speeds, water truck operating, etc.)		
28 Is the area free from any objectionable odors?		
29 Is excessive noise minimized?		

EXHIBIT A
APPENDIX A
ENVIRONMENTAL RULES FOR CONTRACTORS
(continued)

ENVIRONMENTAL FIELD INSPECTION FORM

Water Quality Management	YES	NO
30 Is the storm-water retention pond (if applicable) properly maintained? Retention ponds should be unclogged, mowed, free of weeds, and structurally sound with all erosion and sedimentation barriers in place and in good condition.		
31 Do the water discharge areas look clean? • Free of foam • No sheen • Each outfall clearly labeled		
32 Is the area free from evidence of industrial wastewater discharging to the ground? (e.g. reverse osmosis reject, etc.)		
33 Are all onsite wells locked?		
34 Are all onsite wells in good shape with no damage?		

Tanks, Pipelines	YES	NO
35 Are the tanks or pipes free from any signs of leakage or spillage?		
36 Are the areas on ground around tanks or piping free from evidence of staining or dying vegetation?		
37 Are oil piping systems properly aligned and are supports/foundations in good condition?		
38 Do all above ground tank structures look sound? • No buckling, cracks, wetting, discoloration, blistering • No significant corrosion • No cracks in base/apron • No signs of settlement • No water accumulation inside dike		
39 Are storage tank/piping release detection systems free of oil? (e.g., double-bottom tank, monitoring wells, etc.)		

	YES	NO

ENVIRONMENTAL FIELD INSPECTION FORM

40	Is the Cathodic Protection working properly? Electrical box shows that amps of current is flowing		
41	Is secondary containment for tanks in good condition? • Concrete secondary containment should be free of cracks or penetrations. • Earthen dikes should be free of erosion, oil stains, trash accumulation or undergrowth. • Are valves in proper location to allow adequate drainage from containment?		
42	Is secondary containment for tanks free of product and water?		
43	Are transformers in proper containment and free of leaks?		

Comments:

Inspector's Signature:

Inspector's Name:

Inspector's Title:

Legend:
NA – Not Applicable

NOTE:
1. **This is not a comprehensive environmental inspection sheet. Other federal, State, and local requirements apply to the facility. Not to be used as a substitute for a full compliance audit.**
2. **This inspection is meant to supplement, and does not replace, routine environmental inspections required by federal regulations, State regulations, or facility plans.**
3. **State specific requirements noted only if different from federal requirements.**
4. **A "No" answer indicates a situation that requires immediate action.**

End

ECRC-08-3347 HEARING EXHIBIT - 00000369

Appendix A – Scope of Work
Exhibit B – Clean Fill Criteria

HEARING EXHIBIT - 00000370

APPENDIX A
EXHIBIT B
CLEAN FILL CRITERIA

MEMORANDUM

To: Distribution

From:
Date:
Re: ***Recommended Clean Fill Screening Process for FPL Utility Properties***

Section 376.30701, Florida Statutes (2003) and the Florida Department of Environmental Protection ("FDEP") rule Chapter 62-780, Florida Administrative Code ("F.A.C.") directs the FDEP to apply the Soil Cleanup Target Levels ("SCTLs") of rule Chapter 62-777, F.A.C. to all contaminated sites where a clean up is required. The SCTLs are conservative default cleanup criteria for approximately 500 constituents many of which are naturally occurring in Florida soils. For FPL, this new soils rule mainly impacts construction projects and the cleanup of contaminated sites.

Furthermore, the SCTLs of Chapter 62-777, F.A.C. may be viewed as an indication of whether or not contamination exists at a site. If a clean up is required due to the discovery of "contamination" the FDEP will require a site to meet residential SCTLs for a "no further action" determination. If a site cannot meet residential soil levels, then some sort of engineering control such as an asphalt cover and fencing will be required in addition to an institutional control such as a deed restriction and an agency permit.

Therefore, future liability for FPL may be created unless fill material brought onto FPL Utility property meets the residential levels for any constituents present. It is advisable that FPL sample and perform analytical testing on representative samples of fill material prior to bringing the fill material onto FPL owned or leased property. In this regard, the following sampling and analysis is recommended prior to bringing clean fill onto any FPL owned or leased property:

Incorporate the Purchase of Clean Fill into the Project and Project Schedule.
This will enable your facility to schedule the physical collection and laboratory analysis of one or more representative samples of the specific fill to be brought on site just prior to delivery. Typical laboratory turn around time is 1-2 weeks. Laboratory analyses may be rushed (1-4 business days) at an additional cost (25-100% markup). This is the best way to ensure that the fill being brought onto FPL property will meet the residential clean soil criteria.

Suggested Screening Process
Soil samples should be collected and analyzed for the clean fill parameters. The standard clean soil parameters are arsenic, barium, cadmium, chromium, lead, selenium, silver, PCBs, and TRPH.

If time permits (i.e., non-rush or pre-qualification samples), it is recommended that the samples first be tested for arsenic as a screening tool. If the arsenic residential SCTL is met, then the laboratory can test the existing soil samples for the remaining clean soil parameters as determined necessary. If time is of the essence (i.e. rush analyses required), samples should be analyzed for all listed parameters at once.

Finally, it should be noted that any fill material that is to be reused on site should undergo the same process, and pass analytical screening for Chapter 62-777, F.A.C. constituents at residential levels.

ECRC-08-3349 HEARING EXHIBIT - 00000371

EXHIBIT A
APPENDIX B
CLEAN FILL CRITERIA
(continued)

RESIDENTIAL SOIL CLEANUP TARGET LEVELS (SCTLs)*
Per Chapter 62-777 F.A.C.
Updated May 16,2005

CONSTITUENT	mg/kg
Arsenic	2.1
Barium	120
Cadmium	82
Chromium	210
Lead	400
Selenium	440
Silver	410
PCBs	0.5
TRPH	460

Note:

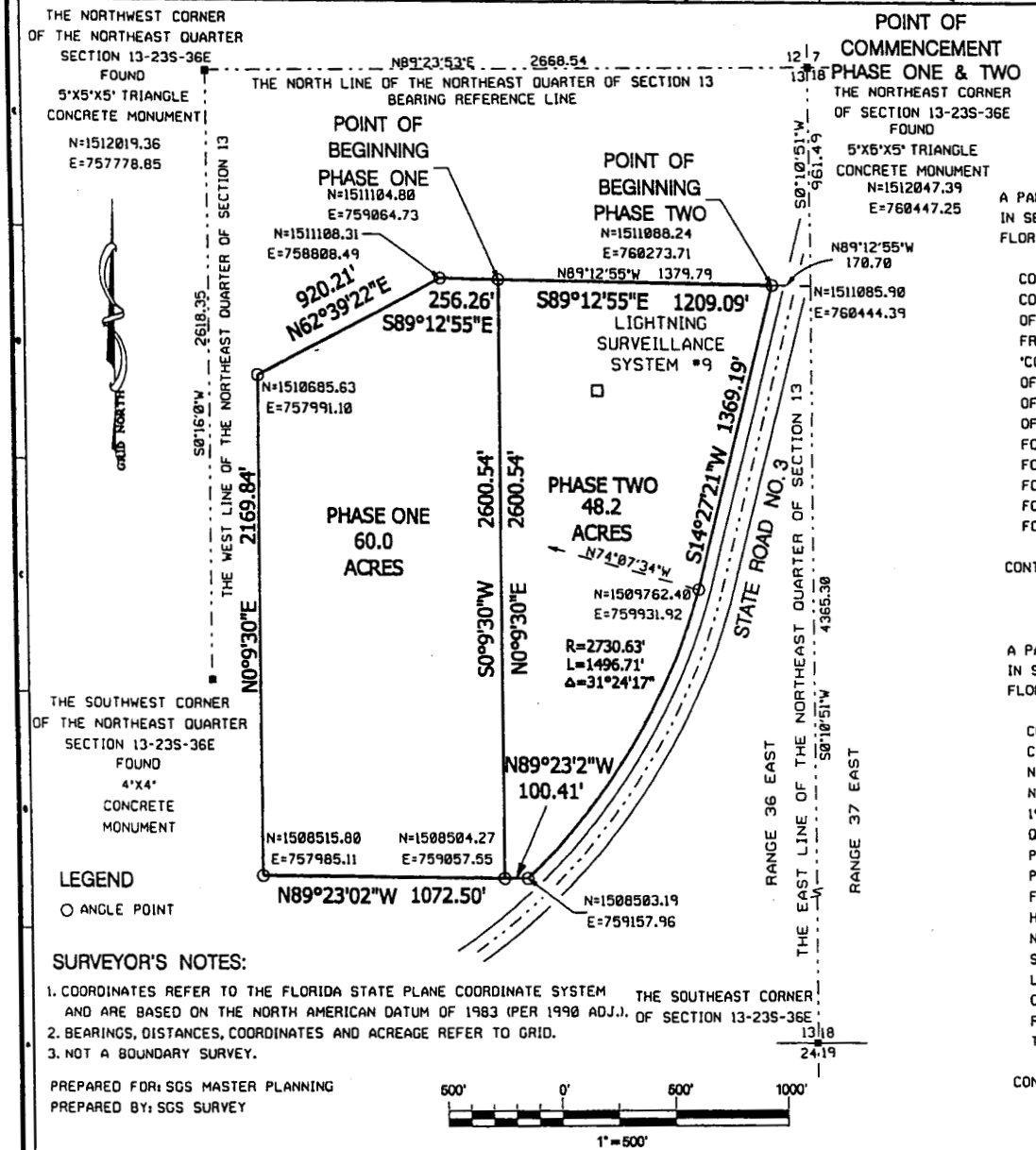
The SCTLs are regulatory-derived values that are subject to periodic review. To ensure that the most up-to-date values are used, consult Chapter 62-777 Florida Administrative Code (F.A.C.), Table 2 (www.dep.state.fl.us/waste/quick_topics/rules/), or contact a JES environmental specialist for assistance.
End

Law/dld/cleanfillmemo

ECRC-08-3350 HEARING EXHIBIT - 00000372

Appendix A – Scope of Work
Exhibit C – Site boundary Limits

Appendix A - Exhibit C - Site Boundary Limits (Described in Phase One below)



SURVEYOR'S NOTES:

1. COORDINATES REFER TO THE FLORIDA STATE PLANE COORDINATE SYSTEM AND ARE BASED ON THE NORTH AMERICAN DATUM OF 1983 (PER 1990 ADJ.).
2. BEARINGS, DISTANCES, COORDINATES AND ACREAGE REFER TO GRID.
3. NOT A BOUNDARY SURVEY.

PREPARED FOR: SGS MASTER PLANNING
PREPARED BY: SGS SURVEY

SKETCH OF DESCRIPTION
F.P.L. SOLAR PHOTOVOLTAIC

PHASE ONE

A PARCEL OF LAND LYING ON THE JOHN F. KENNEDY SPACE CENTER, IN SECTION 13, TOWNSHIP 23 SOUTH, RANGE 36 EAST, BREVARD COUNTY, FLORIDA, AND BEING MORE FULLY DESCRIBED AS FOLLOWS:

COMMENCE AT THE NORTHEAST CORNER OF SECTION 13, SAID CORNER HAVING A FLORIDA STATE PLANE COORDINATE VALUE OF NORTH 1512047.39 AND EAST 760447.25 (NAD83), AS DERIVED FROM A NATIONAL GEODETIC SURVEY TRIANGULATION STATION 'COURTENAY 1953'; THENCE S00°10'51"W ALONG THE EAST LINE OF THE NORTHEAST QUARTER OF SAID SECTION 13 FOR A DISTANCE OF 961.49 FEET TO A POINT; THENCE N89°12'55"W FOR A DISTANCE OF 1379.79 FEET TO THE POINT OF BEGINNING; THENCE S0°9'30"W FOR A DISTANCE OF 2600.54 FEET TO A POINT; THENCE N89°23'02" W FOR A DISTANCE OF 1072.50 FEET TO A POINT; THENCE N0°9'30" E FOR A DISTANCE OF 2169.84 FEET TO A POINT; THENCE N62°39'22" E FOR A DISTANCE OF 920.21 FEET TO A POINT; THENCE S89°12'55" E FOR A DISTANCE OF 256.26 FEET TO THE POINT OF BEGINNING.

CONTAINING 60.0 ACRES MORE OR LESS.

PHASE TWO

A PARCEL OF LAND LYING ON THE JOHN F. KENNEDY SPACE CENTER, IN SECTION 13, TOWNSHIP 23 SOUTH, RANGE 36 EAST, BREVARD COUNTY, FLORIDA, AND BEING MORE FULLY DESCRIBED AS FOLLOWS:

COMMENCE AT THE NORTHEAST CORNER OF SECTION 13, SAID CORNER HAVING A FLORIDA STATE PLANE COORDINATE VALUE OF NORTH 1512047.39 AND EAST 760447.25 (NAD83), AS DERIVED FROM NATIONAL GEODETIC SURVEY TRIANGULATION STATION 'COURTENAY 1953'; THENCE S00°10'51"W ALONG THE EAST LINE OF THE NORTHEAST QUARTER OF SAID SECTION 13 FOR A DISTANCE OF 961.49 FEET TO A POINT; THENCE N89°12'55"W FOR A DISTANCE OF 170.70 FEET TO THE POINT OF BEGINNING; THENCE S14°27'21"W FOR A DISTANCE OF 1369.19 FEET TO THE BEGINNING OF A CURVE CONCAVE TO THE NORTHWEST HAVING A RADIUS OF 2730.63 FEET AND TO WHICH A RADIAL LINE BEARS N74°07'34"W; THENCE SOUTHWESTERLY 1496.71 FEET ALONG THE ARC OF SAID CURVE THROUGH A CENTRAL ANGLE OF 31°24'17" TO A NON-TANGENT LINE; THENCE N89°23'02"W ALONG SAID NON-TANGENT LINE FOR A DISTANCE OF 100.41 FEET TO A POINT; THENCE N0°9'30" E FOR A DISTANCE OF 2600.54 FEET TO A POINT; THENCE S89°12'55"E FOR A DISTANCE OF 1209.09 FEET TO THE POINT OF BEGINNING.

CONTAINING 48.2 ACRES MORE OR LESS.

SGS
SPACE GATEWAY SUPPORT
SURVEY SERVICES
KENNEDY SPACE CENTER, FLORIDA

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
JOHN F. KENNEDY SPACE CENTER, NASA
KENNEDY SPACE CENTER, FLORIDA

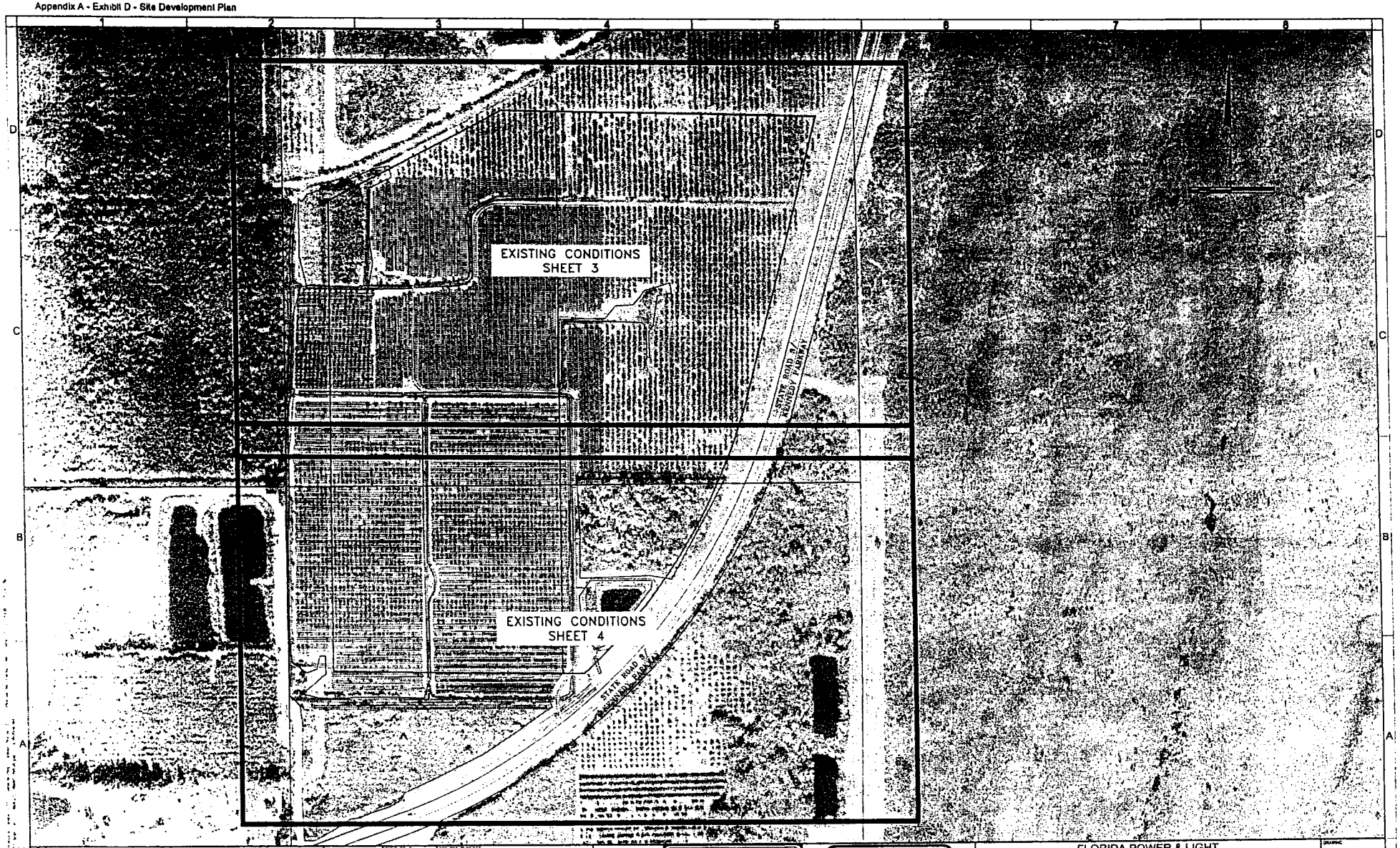
F.P.L SOLAR PHOTOVOLTAIC
LAND DESCRIPTION

NAME	SIGNATURE	DATE
DCL		8-13-08

LEGAL DESCRIPTION

ECRC-08-3352 HEARING EXHIBIT - 00000374

Appendix A – Scope of Work
Exhibit D – Site Development Plan



VERIFY SCALES
BAR IS ONE INCH ON ORIGINAL DRAWING
IF NOT ONE INCH ON THIS SHEET, ADJUST SCALES ACCORDINGLY

DESIGNED BY BF
DRAWN BY BF
CHECKED BY JM
DATE 7/10/2008

PROJECT ENGINEER
RER NUMBER DATE
PROJECT NUMBER 17277.00
CADD SHORTNAME LBFH

BOYLE ARIZONA

BOYLE ENGINEERING
3320 S.W. Corporate Parkway
Palm City, Florida 34990
T. 772-288-3863 F. 772-288-3925
BPR & FBPE License No.'s 3320 & LB7422
www.boyleengineering.com

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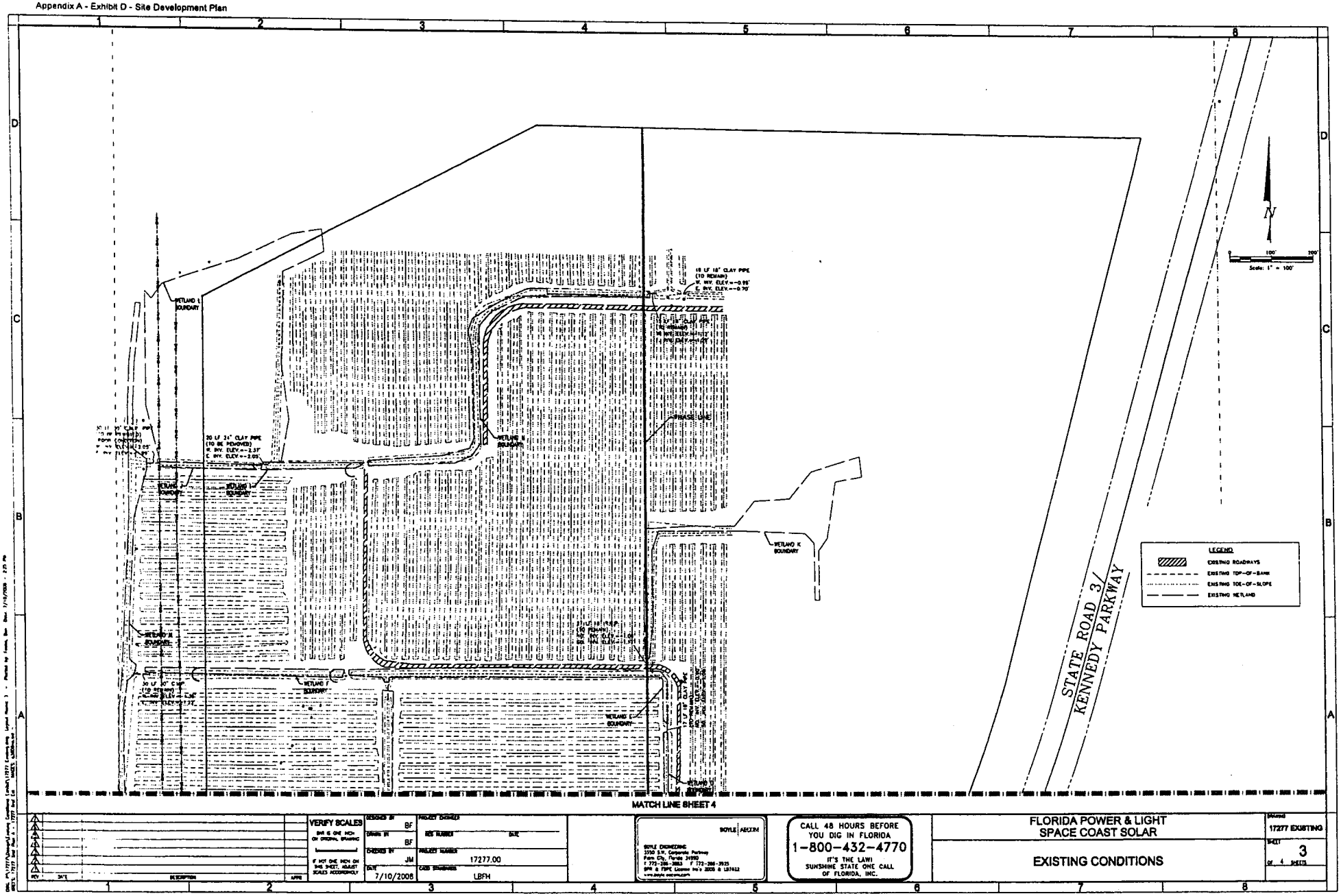
FLORIDA POWER & LIGHT
SPACE COAST SOLAR

KEY SHEET

DRAWING 17277 GENERAL
SHEET 2 OF 4 SHEETS

ECRC-08-3354

HEARING EXHIBIT - 00000376



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DESIGNED BY	BF
DRAWN BY	BF
CHECKED BY	JM
DATE	7/10/2008

PROJECT OWNER
RES NUMBER DATE
PROJECT NUMBER 17277.00
CADD STANDARDS LBFH

BOYLE ENGINEERING
3350 S.W. Corporate Parkway
Palm City, Florida 34990
T 772-286-3883 F 772-286-3935
EB & TSPE License No's 2005 & L07612

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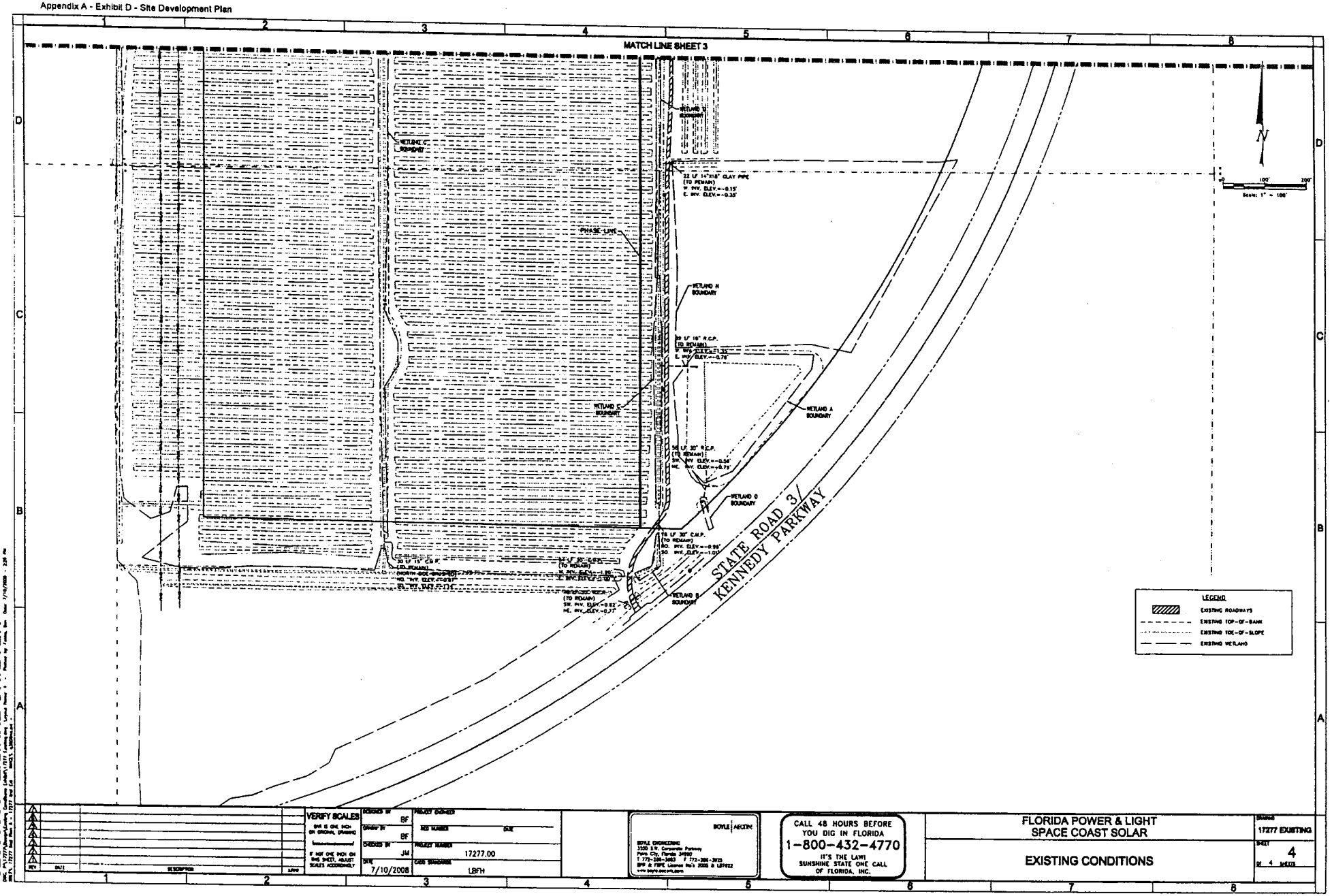
EXISTING CONDITIONS

DRAWING 17277 EXISTING
SHEET 3 OF 4 SHEETS

ECRC-08-3355
HEARING EXHIBIT - 00000377

Appendix A - Exhibit D - Site Development Plan



VERIFY SCALES
BAR IS ONE INCH ON ORIGINAL DRAWING
IF NOT ONE INCH ON THIS SHEET, ADJUST SCALES ACCORDINGLY

DESIGNED BY	BF
DRAWN BY	BF
CHECKED BY	JM
DATE	7/10/2008
PROJECT OWNER	
BID NUMBER	DATE
PROJECT NUMBER	17277.00
CAD STANDARD	LBFH

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3550 S.W. Corporate Parkway
Palm City, Florida 34990
T 772-288-3663 F 772-286-2913
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EXISTING CONDITIONS

Manual 17277 EXISTING
SHEET 4
OF 4 SHEETS

ECRC-08-3356
HEARING EXHIBIT - 00000378

Appendix B – Project Controls Requirements

APPENDIX B
PROJECT CONTROLS REQUIREMENTS

PROJECT CONTROL REQUIREMENTS

1.0 GENERAL PROGRAM REQUIREMENTS

1.1 Provide adequate methods and tools for budget control, scheduling, tracking, trending, and reporting of work in progress for the engineering, procurement and construction activities related to the Project. Owner's intent is to monitor the Agreement at the Project level.

1.2 Identify Contractor's organization.

1.3 Develop and implement a standardized method of invoicing and payment process for work performed.

2.0 SCHEDULE GENERAL REQUIREMENTS

2.1 Bid /Proposal Submittal Requirements

Contractor shall submit a summary schedule with his proposal. This schedule shall be a drafted time-scaled logic diagram that indicates completion of all major activities. Contractor should clearly indicate each contractual milestone submittal date and FPL's deliveries along with Contractors planned completion date, clearly indicating relationships between major activities. Contractor is encouraged to plan for earlier completion dates than the contractual completion dates provided such dates do not interfere with the planned activities of other Contractors or FPL.

2.2 Project Execution Schedule

a. Contractor shall provide an electronic copy (in the most current version of MicroSoft(MS) Project) of Contractor's Construction schedule to FPL within 10 days of Contract award for FPL's approval. The schedule shall be prepared with the understanding that the Contractor's schedule is the Project Master Schedule.

b. Weekly and monthly updates shall be provided to FPL with cut-off dates and submittal dates as determined by FPL. FPL reserves the right of review and approval for the Project Execution Schedule.

c. The schedule shall allow each activity to be assigned to:

- Work Package (No. 1, 2, 3, or 4),
- Area (Unit 3, Unit 4 or Common), and
- Responsibility (Contractor, Engineer, or FPL)

2.3 Schedule Project Progress Reporting (included with Monthly Report)

Within ten (10) days after each calendar month, Contractor shall submit a brief report describing progress from the previous month, an update of the schedule, any commercial or technical issues that remain open, and a matrix of the contract milestones containing the contract date, current scheduled/actual date, and variance between the two.

2.4 Project Schedule Development

a. Contractor's schedule shall be based on FPL's Milestones and Key Dates provided over the course of the Contract.

b. Contractor shall retain responsibility for development and implementation of the schedule covering the scope of work. Contractor retains sole responsibility for meeting schedule Finish Dates.

c. Contractor's Project schedule will include manpower requirements and commodity installation plans. Commodity Installation curves to be developed at a minimum for earthwork, concrete, cable, terminations, panel and support structure installation.

2.5 Project Schedule Integration

a. Contractor shall maintain the project master schedule and integrate other contractor schedules with the mechanical schedule. Also, Contractor shall integrate activities provided by Engineering and FPL for the project into the project master schedule. Contractor schedules shall have a level of detail equivalent to a Level 2 schedule (approximately 100 to 300 activities).

b. The testing, startup of components and systems, and the performance testing shall be integrated by the Contractor into the project master schedule. Contractor shall review the logic to validated correctness of sequence and time durations for all activities in the project master schedule.

3.0 SCHEDULE/PROGRESS MEASUREMENT

3.1 Weekly Progress And Schedule Review

FPL and Contractor representatives shall meet weekly to review the Work progress and update the Work completion schedule. Contractor's representative shall present the following:

a. The current status of their Job Progress.
b. A detailed three week look-ahead schedule
c. Project Milestones current status update and forecast vs. baseline schedule
d. Their current and projected manpower by craft.
e. The material delivery status.
f. The status of drawings and other submittals.
g. Any changes in the Work.
h. The status of "As-Built" Drawings (if required).
i. Problem areas or concerns.

3.2 Progress review meetings will be held weekly at FPL's Jobsite offices.

3.3 Productivity Meetings – Any T&M or Target Price Contractor shall also participate in a weekly productivity meeting with FPL.

3.4 Three Week Look Ahead Schedules

a. Contractor shall develop a 3-week daily work schedule as shown in Attachment 1, Three Week Look Ahead Schedule Example. Generally the schedule shall be submitted to FPL with a copy to all other affected Contractors by the close of business Monday. Any submittals received after 9:00 AM each Tuesday morning shall be considered non-compliant. The exact timing of development may be modified by FPL after commencement of field mobilization.
b. The Three-Week Look Ahead Schedule (3WLAS) will be a bar chart containing activities and durations, area designations, and restraints. Activities shall be planned and scheduled overall consistent with the Project Schedule. The schedule shall be grouped by area.
c. The level of detail required for the 3WLAS shall be determined by the current status of the work and its complexity and coordination with FPL or other Contractors.
d. The key Contractor personnel who will be responsible for working closely with FPL's staff to achieve efficient execution of the Contract shall have the authority to represent Contractor.

3.5 Contractor's three week look-ahead schedule shall:

a. Indicate all planned work and testing that is to be accomplished during the current week and the next two week period all in support of, and in accordance with, Contractor's Construction Schedule.
b. Include major construction equipment requirements
c. Highlight any material or drawing needs from either FPL or Contractor.
d. Reflect the planned and actual activities of the previous week.
e. Include any activities that are required to be accomplished by others that would impact and/or prevent Contractor from starting and/or accomplishing its planned work.
f. Be presented in the level of detail sufficient to direct the efforts of the craft on a day-to-day basis.

4.0 COST REPORTING REQUIREMENTS

4.1 Cost Management Report - Contractor shall provide at a minimum on a bi-weekly basis the Claims, Changes or extra work, delays or accelerations, interferences and the like known to Contractor that have occurred or may be claimed to have occurred since project onset. This information is required to be provided in Microsoft Excel. The report is referred to as the Cost Management Report and will include current status of aforementioned items, initiated dates, dollar exposure amounts (incremental to the executed contract amount), drawing references, subcontractor documentation, etc. as required to establish an understanding of the issues. If there are no known Claims, Changes, etc the Cost Management Report shall still be issued bi-weekly stating NONE. The most recent Cost Management Report shall be attached to each Contractor invoice.

4.2 Contractor shall invoice per the conditions of the contract terms. Additionally at the request of the Owner, Contractor is required to provide an estimate of the next invoice within two business days of the request. It is understood that this request in only an estimate and may be revised with issuance of the formal invoice.

4.3 Contractor shall develop a Work Breakdown Structure (WBS) assigning cost codes encompassing the entire Scope of Work in an adequate level of detail to provide the outlined reporting requirements contained herein. Ultimately, the WBS should be developed in sufficient detail to permit assignment and allocation of costs to the functional classifications specified in the Owner Property Retirement Unit Catalog.

5.0 MATERIAL STATUS

5.1 Contractor shall maintain an updated Materials List and Shipment Origin and Profile Report for materials procured.

5.2 Contractor shall provide a weekly update of the Materials List and Shipment Origin and Profile Report to FPL.

5.3 Contractor, during the Weekly Progress and Schedule Review Meeting, shall provide a list of shortages and late deliveries that could negatively affect construction and installation if not received in a timely manner.

5.4 Contractor shall provide a composite Materials List and Shipment Origin and Profile Report for all FPL procured materials.

6.0 CONTRACTOR'S DAILY REPORT

6.1 Contractor shall submit to FPL's designated field representative prior to 10:00 a.m. each day, starting from the day Contractor mobilizes at the site, a completed and signed Contractor's Daily Force Report utilizing the form provided as Attachment 2, Daily Force Report, hereto. The Daily Force Report shall contain a listing of Contractor and Contractor manpower, including personnel by responsibility, craft, and remarks concerning the daily field activities.

7.0 TIME AND MATERIALS (T&M) WORK

7.1 Any Contract with a T&M contract or an incentive based contract shall fully report progress and expended man-hours at the individual line item level of FPL's EVMS.

7.2 This includes work performed by any Contractor doing Extra Work Order work on a T&M basis.

8.0 MONTHLY PROGRESS REPORT REQUIREMENTS

8.1 Brief narrative overview of Project status.

8.2 Brief narrative of identified critical issues.

8.3 Brief narrative of short term look ahead activities.

8.4 Updated organization chart for the Project.

8.5 Safety and environmental issues/status.

8.6 Project Milestones current status update and forecast vs. baseline schedule

8.7 Contractor Project schedules shall be updated and submitted in adobe acrobat format (pdf). These schedules shall show current status and the projected completion dates of all Project phases against the current planned schedule.

8.8 An electronic copy (data file) of the most recently updated complete MS Project integrated Project Schedule network.

8.9 Cost Management Report

8.10 Manpower curves (manpower plan with actual and forecast to go over time)

8.11 Progress curves (% Complete progress versus time).

8.12 Construction commodity curves (actual vs. original baseline and current plan) as identified in Section 2.4c above. A variance explanation and/or recovery plan shall be provided by Contractor should progress monitored on fall behind the plan.

8.13 Procurement Status Report. A complete listing of all equipment and materials to be procured by the Contractor, including status of the procurement process (bid, evaluate & award). The information included in this report shall be consistent and support the Project Schedule.

APPENDIX B
PROJECT CONTROLS REQUIREMENTS
(continued)

Attachments

Attachment 1 - Three Week Look Ahead Schedule Example

Attachment 2 - Daily Force Report

ECRC-08-3361 HEARING EXHIBIT - 00000383

Project Name Here
Project Number Here
Prepared By:

Exhibit B, Attachment 1 - Three Week Look Ahead Schedule Example

Date: _____

P3 ACTIVITY ID	ACTIVITY DESCRIPTION	Last Week Beginning: Sun	Mon	Tue	Wed	Thu	Fri	Sat	Current Week Beginning: Sun	Mon	Tue	Wed	Thu	Fri	Sat	Week 2 Beginning: Sun	Mon	Tue	Wed	Thu	Fri	Sat	Week 3 Beginning: Sun	Mon	Tue	Wed	Thu	Fri	Sat	P3 Target Completion Date	COMMENTS

APPENDIX B
PROJECT CONTROLS REQUIREMENTS
(continued)

Attachment 2 - Daily Force Report

Contract No._____ Date_____

Contractor			Project						
Days/Week		Shifts					Hours/Shift		
Weather		Temperature a.m. p.m.					Work Days on Job		
Personnel	General Foreman	Foreman	Journeyman	Helper	Total	M/Hr Today	Absent	Equipment	No.
Boilermakers								Trucks-Pickup	
Ironworkers-Struct								Trucks-Dump, Flatbed	
Ironworkers-Rebar								Air Compressors	
Millwrights								Tractors	
Oper. Engineers								Crawler-Backhoe	
Testers								Tractor-Backhoe	
Pipefitters								Welding Mach.-Elec	
Carpenters								Welding Mach.-Comb.	
Cement Finishers								Office Trailer	
Laborers								Winch Trucks	
Bricklayers								Cranes Cap	
Electricians								Cranes Cap	
Painters								Cranes Cap	
Insulators								Other	
Sheet Metalworkers									
Roofers									
Clerical Help									
Engineering Asst									
QC Inspectors									
NDE Technicians									
Superintendent									
TOTALS								TOTALS	

COMMENTS:_____

Signature: _____

Appendix C – Critical Milestones and Milestones

HEARING EXHIBIT - 00000386

APPENDIX C

CRITICAL MILESTONES
SPACE COAST PROJECT

1. Mobilize for Construction	9/1/09
2. Begin Foundation Work	9/15/09
3. Foundations Complete	12/15/09
4. Steel Frame Complete	1/15/10
5. Communications Infrastructure for DAS Complete	2/9/10
6. 40% Electrical Complete (4 MW)	4/1/10
7. 100% Electrical Complete	5/26/10
8. Provisional Acceptance	6/30/10

Appendix D – Construction and Milestone Payment Schedule

Appendix E – Credit Trigger Event

Appendix F – Form of Request for Payment

APPENDIX F

FORM OF REQUEST FOR PAYMENT

TO: Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

ATTN:

APPLICATION FOR MILESTONE PAYMENT

FPL Purchase Order No.: _____ DATE: _____

Supplier's Invoice No.: _____

Milestone Number	Milestone Description	Total Activity Value	Activity Value Requested for Payment

Total This Application $_____

ORIGINAL CONTRACT PRICE	$	
Net Change By Change Order	$	
CONTRACT PRICE TO DATE	$	
Less Payments by Owner to Subcontractors	$	
Less Prior Applications for Payment	$	
CURRENT APPLICATION FOR PAYMENT	$	
Less Retention	$	
Net Current Payment	$	
BALANCE OF CONTRACT PRICE	$	

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Appendix G – Form of Final Acceptance Certificate

HEARING EXHIBIT - 00000392

APPENDIX G

Form of Final Acceptance Certificate

(Page 1 of 2)

Date: _____

1. Unless otherwise defined herein, the capitalized terms used throughout this certificate shall have the meanings ascribed to same in the Turnkey Engineering, Procurement and Construction Agreement for Solar Photovoltaic Generating Facility dated as of July [__], 2008 (as the same may be amended, modified and supplemented from time to time, the "Agreement") by and between Florida Power & Light Company, a Florida corporation ("FPL") and SunPower Corporation, Systems, a Delaware Corporation ("Contractor").

2. Contractor certifies and represents that the following statements are true as of the date of delivery hereof to FPL:

   a) The Contractor has satisfied all of the requirements for the achievement of Final Acceptance in accordance with the Agreement.

   b) Contractor has delivered this form, completed except for signature by FPL, to FPL's duly authorized representative referred to in Section 4.11 of the Agreement on the above date.

3. The person signing below is authorized to submit this form to FPL for and on behalf of Contractor.

SunPower Corporation, Systems,
as Contractor

By: _____
Name: _____
Title: _____

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Appendix G

Form of Final Acceptance Certificate
(Page 2 of 2)

FPL to cross through one (1) of the following statements:

A. FPL agrees that Final Acceptance has been achieved. This Certificate was received by FPL on the date first written above and is effective as of that date.

B. FPL does not agree that Final Acceptance has been achieved by the Contractor due to the following:

_____

_____

_____

_____

FPL:

The person signing below is authorized to sign the Final Acceptance Certificate for and on behalf of FPL.

By: _____ Date: _____
Name: _____
Title: _____

ECRC-08-3374 HEARING EXHIBIT - 00000394

Appendix H – Form of Contractor Certificate for Partial Waiver of Liens

APPENDIX H

FORM OF CONTRACTOR CERTIFICATE FOR PARTIAL WAIVER OF LIENS

This CONTRACTOR'S PARTIAL LIEN WAIVER AND RELEASE ("Contractor's Partial Lien Waiver and Release") is made by SunPower Corporation, Systems, a Delaware corporation ("Contractor"), on behalf of itself, its successors and assigns, and those acting by or through any of the foregoing, for and in consideration of the sum of [AMOUNT OF PARTIAL PAYMENT REQUEST] DOLLARS ($[_____]) (the "Progress Payment") and other good and valuable consideration, in hand paid, the receipt and sufficiency of which are hereby acknowledged, as full payment on account of all labor, services, materials, equipment and other work performed through the ___ day of _____, 200_ (the "Release Date"), for Florida Power & Light Company, a Florida corporation ("Owner"), in connection with the construction of a solar photovoltaic electric generation facility, and all services and utilities related thereto, in Brevard County, Florida (such facility, together with the property on which such facility is located, the "Project"), pursuant to that certain TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT FOR SOLAR PHOTOVOLTAIC GENERATING FACILITY, dated as of July [__], 2008, between Owner and Contractor, as the same may be amended from time to time (as the same may be amended, modified and supplemented from time to time, the "Agreement").

Solely with respect to the Work performed by the Contractor relating to the Project on or prior to the Release Date, the Contractor does hereby unconditionally and irrevocably waive, release, remise, relinquish and quit-claim (collectively, the "Release") all actions, claims, demands, liens, lien rights and claims of lien, of any kind whatsoever (collectively, "Claims"), which Contractor ever had or now has, known or unknown, against the Project or against Owner, its parents, subsidiaries and affiliates, at all tiers, and its and their insurers, sureties, employees, officers, directors, representatives, shareholders, agents, and all parties acting for any of them (collectively, the "Released Entities"), including, without limitation, all claims related to, in connection with, or arising out of, all facts, acts, events, circumstances, changes or extra work, constructive or actual delays or accelerations, interferences and the like, which have occurred or may be claimed to have occurred. The foregoing Release shall only be effective with respect to Claims arising in connection with the portion of the work performed by Contractor prior to the Release Date.

The Contractor warrants and represents, solely with respect to all Work completed through the Release Date that (a) the Contractor has not assigned or pledged any rights or claims in any amount due or to become due from Owner in connection with the Project; (b) payment has been or will be made to all subcontractors, laborers and material suppliers, at all tiers, for all labor, services, materials and equipment furnished by or through the Contractor for the Project, including all payroll taxes and contributions required to be made; (c) no claims from subcontractors, vendors, mechanics or materialmen against the Released Entities have been submitted to Contractor with respect to the Project or remain unsatisfied as of the date hereof; (d) no mechanics' or materialmen's liens have been filed with respect to the Project that have not been discharged or for which a bond has not been posted in accordance with the Agreement; and (e) payment of all amounts due has been made to all consultants, employees, subcontractors, laborers and material suppliers, at all tiers, and all other entities, for all labor, services, materials and equipment furnished by or through Contractor for the Project, including, without limitation, all payroll taxes and contributions required to be made and all wages, overtime pay, premium pay, holiday pay, sick pay, personal leave pay, severance pay, fees, fringe benefits, commissions

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and reimbursable expenses required to be paid and all deductions for dues, fees or contributions required to be made in connection with all collective bargaining agreements in existence, if any, which affect any worker(s) providing services for the Project.

Solely with respect to all Work for the Project completed through the Release Date, the Contractor agrees to defend, indemnify and hold the Released Entities harmless from and against any and all actions, causes of action, losses or damages of whatever kind, including, without limitation, reasonable attorneys' fees and costs in arbitration and at the pre-trial, trial and appellate levels, which the Released Entities may suffer by reason of (a) any claim made against the Project or any of the Released Entities relating to labor, services, materials or equipment furnished by or through the Contractor in connection with the Project, or (b) any breach of any representation or warranty made by the Contractor to Owner in connection with the Project, including the representations and warranties included herein, any false statement made in this Contractor's Partial Lien Waiver and Release or any misrepresentation or omission made to Owner by the Contractor.

The Contractor acknowledges and agrees that (a) Owner is relying upon the representations and warranties made herein as a material inducement for Owner to make the Progress Payment to the Contractor; (b) this Contractor's Partial Lien Waiver and Release is freely and voluntarily given by the Contractor, and the Contractor has had the advice of counsel in connection herewith and is fully informed as to the legal effects of this Contractor's Partial Lien Waiver and Release, and the Contractor has voluntarily accepted the terms herein for the consideration recited above; and (c) the tendering of the Progress Payment by Owner and the receipt of the Progress Payment and the execution of this Contractor's Partial Lien Waiver and Release by the Contractor shall not, in any manner whatsoever, release the Contractor from (i) its continuing obligations with respect to the completion of any work at the Project that remains incomplete, including warranty work or guaranty work, or the correction of defective or non-conforming work; (ii) any contractual, statutory or common law obligations of the Contractor with respect to the Released Entities in connection with the Project; or (iii) any other obligations of the Contractor with respect to Released Entities in connection with the Project.

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SIGNATURES APPEAR ON FOLLOWING PAGE.]

ECRC-08-3377 HEARING EXHIBIT - 00000397

Dated this ___day of _____, 200__.

SUNPOWER CORPORATION, SYSTEMS:

WITNESSES:

_____
Name:_____

_____
Name:_____

By:_____
Name:_____
Title:_____
Address:_____
_____
_____

NOTARIAL ACKNOWLEDGMENT

STATE OF _____)
) **ss:**
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 200__, by _____, the _____ of SunPower Corporation, Systems, a Delaware corporation, who executed the foregoing instrument on behalf of said corporation, and who is personally known to me or who produced _____ as identification.

_____
Name: _____
Notary Public, State of [Florida]
[If notarized in a State other than Florida, Signatory shall comply with the notary requirements of such State.]
Commission No._____
My Commission expires: _____
(Seal)

ECRC-08-3378 HEARING EXHIBIT - 00000398

Appendix H-1 – Form of Subcontractor Certificate for Partial Waiver of Liens

APPENDIX H-1

FORM OF SUBCONTRACTOR CERTIFICATE FOR PARTIAL WAIVER OF LIENS

This SUBCONTRACTOR'S PARTIAL LIEN WAIVER AND RELEASE is made by [_____], a [_____] (the "Releasor"), subcontractor to SunPower Corporation, Systems, a Delaware corporation ("Contractor"), on behalf of Releasor, its successors and assigns, and those acting by or through any of the foregoing, for and in consideration of the sum of Ten and No/100 DOLLARS ($10.00) and other good and valuable consideration, in hand paid, the receipt and sufficiency of which are hereby acknowledged, as full payment on account of all labor, services, materials, equipment and other work furnished through the ___ day of _____, 200_ (the "Release Date"), for work in connection with the construction of a solar photovoltaic electric generation facility, and all services and utilities related thereto, in Brevard County, Florida (such facility, together with the property on which such facility is located, the "Project") by Contractor on behalf of Florida Power & Light Company, a Florida corporation ("Owner").

Solely with respect to the work performed by the Releasor on or prior to the Release Date in connection with the Project, the Releasor does hereby unconditionally and irrevocably waive, release, remise, relinquish and quit-claim (collectively, the "Release") all actions, claims, demands, liens, lien rights and claims of lien, of any kind whatsoever (collectively, "Claims"), which Releasor ever had or now has, known or unknown, against the Project or against Owner or Contractor, their partners, parents, subsidiaries and affiliates, at all tiers, and their insurers, sureties, employees, officers, directors, representatives, shareholders, agents, and all parties acting for any of them (collectively, the "Released Entities"), including, without limitation, all claims related to, in connection with, or arising out of, all facts, acts, events, circumstances, changes or extra work, constructive or actual delays or accelerations, interferences and the like, which have occurred or may be claimed to have occurred. The foregoing Release shall only be effective with respect to Claims arising in connection with the portion of the work performed by Releasor prior to the Release Date.

The Releasor warrants and represents, solely with respect to all work by Releasor completed for the Project through the Release Date, that (a) the Releasor has not assigned or pledged any rights or claims in any amount due or to become due from Contractor in connection with the Project; (b) payment has been or will be made to all of its subcontractors, laborers and material suppliers, at all tiers, for all labor, services, materials and equipment furnished by or through the Releasor for the Project, including all payroll taxes and contributions required to be made; (c) no claims from any of its subcontractors, vendors, mechanics or materialmen against the Released Entities in connection with the Project have been submitted to Releasor with respect to the Project or remain unsatisfied as of the date hereof; (d) no mechanics' or materialmen's liens have been filed with respect to the Project that have not been discharged; and (e) payment of all amounts due has been made to all consultants, employees, subcontractors, laborers and material suppliers, at all tiers, and all other entities, for all labor, services, materials and equipment furnished by or through Releasor for the Project, including, without limitation, all payroll taxes and contributions required to be made and all wages, overtime pay, premium pay, holiday pay, sick pay, personal leave pay, severance pay, fees, fringe benefits, commissions and reimbursable expenses required to be paid and all deductions for dues, fees or contributions required to be made in connection with all collective bargaining agreements in existence, if any, which affect any worker(s) providing services for the Project.

ECRC-08-3380 HEARING EXHIBIT - 00000400

Solely with respect to all work by Releasor in connection with the Project completed through the Release Date, the Releasor agrees to defend, indemnify and hold the Released Entities harmless from and against any and all actions, causes of action, losses or damages of whatever kind, including, without limitation, reasonable attorneys' fees and costs in arbitration and at the pre-trial, trial and appellate levels, which the Released Entities may suffer by reason of (a) any claim made against the Project or any of the Released Entities relating to labor, services, materials or equipment furnished by or through the Releasor, or (b) any breach of any representation or warranty made by the Releasor to the Released Entities, including the representations and warranties included herein, any false statement made in this Subcontractor's Partial Lien Waiver and Release, or any misrepresentation or omission made to the Released Entities by the Releasor.

The Releasor acknowledges and agrees that (a) the Contractor and Owner are relying upon the representations and warranties made herein as a material inducement for the Contractor to make payment to the Releasor; (b) this Subcontractor's Partial Lien Waiver and Release is freely and voluntarily given by the Releasor and the Releasor has had the advice of counsel in connection herewith and is fully informed as to the legal effects of this Subcontractor's Partial Lien Waiver and Release and the Releasor has voluntarily accepted the terms herein for the consideration recited above; and (c) the tendering of payment by the Contractor and the receipt of payment and the execution of this Subcontractor's Partial Lien Waiver and Release by the Releasor shall not, in any manner whatsoever, release the Releasor from (i) its continuing obligations with respect to the completion of any work at the Project that remains incomplete, including warranty work or guaranty work, or the correction of defective or non-conforming work; (ii) any contractual, statutory or common law obligations of the Releasor with respect to any of the Released Entities in connection with the Project; or (iii) any other obligations of the Releasor with respect to any of the Released Entities in connection with the Project.

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SIGNATURES APPEAR ON FOLLOWING PAGE.]

ECRC-08-3381 HEARING EXHIBIT - 00000401

Dated this ___day of _____, 200__.

WITNESSES:

_____
Name:_____

_____
Name:_____

Subcontractor:

By: _____
Name:_____
Title:_____
Address:_____
_____
_____

NOTARIAL ACKNOWLEDGMENT

STATE OF _____)
) **ss:**
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 200__, by _____, the _____ of_____, a _____, who executed the foregoing instrument on behalf of said corporation, and who is personally known to me or who produced _____ as identification.

_____
Name: _____
Notary Public, State of [Florida] **[If notarized in a State other than Florida, Signatory shall comply with the notary requirements of such State.]**
Commission No._____
My Commission expires: _____
(Seal)

ECRC-08-3382 HEARING EXHIBIT - 00000402

Appendix I – Form of Contractor Parent Guaranty

APPENDIX I

FORM OF CONTRACTOR PARENT GUARANTY

THIS GUARANTY (this "Guaranty"), dated as of July [__], 2008, is issued by SunPower Corporation, a Delaware corporation (the "Guarantor"), in favor of Florida Power & Light Company, a Florida corporation ("Owner").

Pursuant to Section 11.8 of Turnkey Engineering, Procurement and Construction Agreement for Solar Photovoltaic Generating Facility dated as of July [__], 2008, (as the same may be amended, modified and supplemented from time to time, the "Agreement") by and between SunPower Corporation, Systems, a Delaware corporation, and of which Guarantor is the parent (the "Subsidiary"), and Owner, Guarantor hereby covenants and agrees with Owner as follows:

Section 1. Definitions. Capitalized terms used herein and not otherwise defined shall have their respective meanings as set forth in the Agreement.

Section 2. Guaranty.

(a) Guaranty. Guarantor hereby irrevocably and unconditionally guarantees, as primary obligor and not merely as surety, to and for the benefit of Owner and any successor or permitted assignee of Owner under the Agreement, the full and prompt payment and performance by Subsidiary of each and every payment and performance obligation of Subsidiary arising under the Agreement (whether such obligation presently exists or is created, incurred or arising from time to time hereafter), including, without limitation, the payment when due of any indemnities, refunds and liquidated damages payable at any time under the Agreement, all amounts payable to Owner pursuant to Section 3(a) of this Guaranty and the performance of the Work (the "Guaranteed Obligations"). Guarantor further agrees that if Subsidiary shall fail to pay or perform in full when due all or any part of the Guaranteed Obligations, Guarantor will immediately pay or perform the same upon demand.

(b) Absolute Guaranty. Subject to Section 2(e) of this Guaranty, Guarantor agrees that its obligations under this Guaranty are irrevocable, absolute, independent and unconditional and shall not be affected by any circumstance that constitutes a legal or equitable discharge of a guarantor or surety other than payment and performance in full of the Guaranteed Obligations. In furtherance of the foregoing and without limiting the generality thereof, Guarantor agrees, subject to the other terms and conditions hereof, as follows:

(i) this Guaranty is a guaranty of payment and performance and not of collectibility;

(ii) Owner may from time to time, without notice or demand and without affecting the validity or enforceability of this Guaranty or giving rise to any limitation, impairment or discharge of Guarantor's liability hereunder, (A) create new obligations or liabilities under the Agreement or renew, extend, accelerate or otherwise change the time, place, manner or terms of the Guaranteed Obligations or otherwise amend or modify the Agreement or change the terms of the Guaranteed Obligations or any part thereof, (B) settle, compromise, release or discharge, or accept or refuse any offer of payment of, or substitutions for, the Guaranteed Obligations or any agreement relating thereto and/or subordinate the payment of the same to the payment of any other obligations, (C) request or accept other guaranties of the Guaranteed Obligations, (D) take and hold security for the payment of this Guaranty or the Guaranteed Obligations, (E) substitute, release, exchange, compromise, subordinate or modify, with or without consideration, any security for payment of the Guaranteed Obligations, any other guaranties of the Guaranteed Obligations, or any other obligation of any Person with respect to the Guaranteed Obligations, (F) enforce and apply any security now or hereafter held by or for the benefit of Owner in respect of this Guaranty or the Guaranteed Obligations and direct the order or manner of sale thereof, or exercise any other right or remedy that Owner may have against any such security, as Owner in its discretion may determine consistent with the Agreement and any applicable security agreement, notwithstanding that such action operates to impair

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or extinguish any right of subrogation, reimbursement, indemnification or contribution or any other right or remedy of Guarantor against Subsidiary or any other guarantor of the Guaranteed Obligations or any other guaranty of or security for the Guaranteed Obligations, (G) assign the Guaranteed Obligations in whole or in part to the extent provided in the Agreement, or (H) exercise any other rights available to Owner under the Agreement, at law or in equity; and

(iii) this Guaranty and the obligations of Guarantor hereunder shall be valid and enforceable and shall not be subject to any limitation, impairment or discharge for any reason (other than payment in full of the Guaranteed Obligations and as otherwise set forth in this Guaranty), including, without limitation, the occurrence of any of the following, whether or not Guarantor shall have had notice or knowledge of any of them: (A) any failure to assert or enforce, or agreement not to assert or enforce, or the stay or enjoining, by order of court, by operation of law or otherwise, of the exercise or enforcement of, any claim or demand or any right, power or remedy with respect to the Guaranteed Obligations or any agreement relating thereto, or with respect to any other guaranty of or security for the payment of the Guaranteed Obligations; (B) any waiver, amendment or modification of, or any consent to departure from, any of the terms or provisions of the Agreement or any agreement or instrument executed pursuant thereto or of any other guaranty or security for the Guaranteed Obligations; (C) the Guaranteed Obligations, or any agreement relating thereto, at any time being found to be illegal, invalid or unenforceable in any respect; (D) the personal or corporate incapacity of any Person; (E) the bankruptcy, receivership or insolvency of Subsidiary or any other Person, or the discharge of Subsidiary's or any other Person's obligations in any bankruptcy, receivership or similar proceeding; (F) any merger or consolidation of Subsidiary or Guarantor into or with any other Person, or any sale, lease or transfer of any of the assets of Subsidiary or Guarantor to any other Person, (G) any change in the ownership of any interests of Subsidiary or any change in the relationship between Subsidiary and Guarantor, or any termination of such relationship or (H) any other act or thing or omission, or delay to do any other act or thing, which may or might in any manner or to any extent vary the risk of Guarantor as an obligor in respect of the Guaranteed Obligations.

(c) **Payments**. All payments made by Guarantor hereunder shall be made without set-off or counterclaim and without any deduction or withholding for any reason, except as expressly provided to the contrary in the Agreement. All payments hereunder shall be made in U.S. dollars in immediately available funds.

(d) **Reinstatement**. Notwithstanding anything to the contrary contained herein, this Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time any payment, or part thereof, under this Guaranty is rescinded or must otherwise be returned or restored by Owner upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of, or similar event affecting, Subsidiary or Guarantor, or any substantial part of either's property, or otherwise, all as though such payment had not been made.

(e) **Defenses**. Notwithstanding anything herein to the contrary, Guarantor specifically reserves to itself all rights, counterclaims and other defenses that the Subsidiary is or may be entitled to arising from or out of the Agreement, except for any counterclaims or defenses arising out of the bankruptcy, insolvency, dissolution or liquidation of the Subsidiary, the lack of power or authority of the Subsidiary to enter into the Agreement or to perform its obligations thereunder, or the lack of validity or enforceability of the Subsidiary's obligations under the Agreement or any transaction thereunder.

Section 3. Other Provisions of the Guaranty.

(a) **Costs and Expenses**. The prevailing party in any action or proceeding shall be entitled to recover from the other party all of its reasonable costs and expenses incurred in connection with such action or proceeding, including reasonable attorneys' fees and costs at the trial court and all appellate levels.

ECRC-08-3385 HEARING EXHIBIT - 00000405

(b) **Waivers by Guarantor**. Guarantor hereby waives for the benefit of Owner, to the maximum extent permitted by Applicable Laws:

(i) all of the following: (A) notice of acceptance hereof or of any matter referred to in Section 2 hereof, (B) all presentments and demands for payment, (C) notices of default, nonpayment, protests, notices of protest, notices of dishonor and notices of any renewal, extension or modification of the Guaranteed Obligations or any agreement related thereto, (D) notice of any action taken or omitted to be taken by Owner in reliance hereon and any and all notices which may or might be lawfully waived by Guarantor, (E) any requirement that Owner be diligent or prompt in making demands hereunder or in giving notice to Guarantor of any default by Subsidiary, or asserting any other rights of Owner hereunder against Subsidiary, (F) any requirement that Owner protect, secure, perfect or insure any security interest or lien or any property subject thereto, (G) any bankruptcy, insolvency, reorganization, arrangement, adjustment, composition, liquidation or similar event of either Subsidiary or Guarantor that might constitute a defense to any payment required under the Agreement or hereunder, (H) any event, occurrence or other circumstance which might otherwise constitute a legal or equitable discharge of a surety or guarantor, including any defense based upon any law, rule or regulation which provides that the obligation of a surety must not be greater or more burdensome than the obligation of the principal, (I) any defense arising by reason of the incapacity, lack of authority or any disability or other defense of Subsidiary including, without limitation, any defense based on or arising out of the lack of validity or the unenforceability of the Guaranteed Obligations or any agreement or instrument relating thereto or by reason of the cessation of the liability of Subsidiary from any cause other than payment in full of the Guaranteed Obligations or termination of this Guaranty in accordance with its terms, (J) any defense arising out of any election by Owner to foreclose on any security held by or for the benefit of Owner pursuant to one or more judicial or nonjudicial sales, even though such election operates to impair or extinguish any right of subrogation, reimbursement, indemnification or contribution or any other right or remedy of Guarantor against Subsidiary or any other guarantor of the Guaranteed Obligations or any other guaranty of or any security for the Guaranteed Obligations, (K) the benefit of any statute of limitations affecting Guarantor's liability hereunder or the enforcement hereof, and (L) any rights to set-offs, recoupments and counterclaims;

(ii) any requirement, and any right to require, as a condition of payment by Guarantor, (A) that any right or power be exercised or any action be taken against either Subsidiary, any other guarantor or any collateral security for the Guaranteed Obligations, (B) that Owner proceed against or exhaust any security held from Subsidiary or any other person, or (C) that Owner pursue any other remedy in Owner's power whatsoever, and Guarantor waives the right to have the property of Subsidiary first applied to the discharge of the Guaranteed Obligations. Owner may, at its election, exercise any right or remedy it may have against Subsidiary or any security now or hereafter held by Owner. Guarantor waives (D) any principles or provisions of Applicable Laws, statutory or otherwise, that are or might be in conflict with the terms of this Guaranty and any defense based on the discharge of Subsidiary by operation of Applicable Laws, notwithstanding any intervention or omission by Owner, including any defenses or benefits that may be derived from or afforded by Applicable Laws (whether now in effect or hereafter adopted) that limit the liability of or exonerate guarantors or sureties, and (E) any defense based on or arising out of the absence, impairment or loss of any right of subrogation, reimbursement, indemnification or contribution or any other right or remedy of Guarantor against Subsidiary or any such security, whether resulting from such election by Subsidiary or otherwise; and

(iii) all rights and benefits under (A) provisions of Applicable Laws purporting to (1) reduce the obligation of a surety or guarantor upon the acceptance by a creditor of anything in partial satisfaction of an obligation, (2) exonerate a surety or guarantor if by any act of the creditor, without the consent of the surety or guarantor, the original obligation of the principal is altered in any respect, or the remedies or rights of the creditor against the principal, in respect thereto, are in any way impaired or suspended (it being expressly understood and agreed that Owner may compromise, settle, alter, extend, waive, amend, suspend or surrender any Guaranteed Obligation or

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any right or remedy with respect thereto without notice to or consent by Guarantor and without affecting Guarantor's obligations hereunder), (3) exonerate the surety or guarantor to the extent that the creditor does not proceed against the principal, or pursue any other remedy in the creditor's power which the surety or guarantor cannot pursue, and which would lighten the surety's or guarantor's burden, and (4) reduce a surety's or guarantor's obligations in proportion to the principal obligation, and (B) provisions of Applicable Laws requiring or permitting creditors or lienors to marshal assets or liens; it being the intention hereof that Guarantor shall remain liable as principal, to the extent set forth in this Guaranty, for so long as this Guaranty shall remain in effect, notwithstanding any act, omission or thing which might otherwise operate as a legal or equitable discharge of the Guarantor other than the payment in full of the Guarantee Obligations.

(c) **Deferral of Subrogation**. Until such time as all of the Guaranteed Obligations have been fully satisfied, notwithstanding any payment made by Guarantor hereunder or the receipt of any amounts by Owner with respect to the Guaranteed Obligations: (i) Guarantor (on behalf of itself, its successors and assigns, including any surety or guarantor) agrees not to exercise any all rights it may have at law or in equity (including, without limitation, any law subrogating Guarantor to the rights of Owner) to seek subrogation, contribution, indemnification, or any other form of reimbursement from Subsidiary, any other guarantor, or any other Person now or hereafter primarily or secondarily liable for any of the Guaranteed Obligations of Subsidiary to Owner, for any disbursement made by Guarantor under or in connection with this Guaranty or otherwise; and (ii) Guarantor agrees not to obtain any benefit of, and any right to participate in, any security, whether real or personal property, now or hereafter held by Owner for the Guaranteed Obligations.

Section 4. Representations and Warranties of Guarantor. Guarantor hereby represents and warrants to Owner as follows:

(a) Guarantor is duly organized, validly existing and in good standing under the laws of its jurisdiction of organization;

(b) Guarantor has full power, authority and legal right to execute and deliver this Guaranty and all other instruments, documents and agreements required by the provisions of this Guaranty to be executed, delivered and performed by Guarantor, and to perform its obligations hereunder and thereunder;

(c) The execution, delivery and performance of this Guaranty and all other instruments, documents and agreements required by the provisions of this Guaranty to be executed, delivered and performed by Guarantor have been duly authorized by all necessary company action on the part of Guarantor;

(d) This Guaranty has been duly executed and delivered by Guarantor and constitutes the legal, valid and binding obligation of Guarantor, enforceable against it in accordance with its terms; and

(e) All necessary action has been taken under Applicable Laws to authorize the execution, delivery and performance of this Guaranty. No governmental approvals or other consents, approvals, or notices of or to any Person are required in connection with the execution, delivery, performance by Guarantor or the validity or enforceability, of this Guaranty.

Section 5. Notices. All notices and other communications provided for hereunder must be in writing to be effective and shall be deemed to be delivered and received (a) if personally delivered or if delivered by courier service, when actually received by the party to whom notice is sent, (b) if delivered by facsimile, on the first Business Day following the day transmitted, or (c) if delivered by mail (whether actually received or not), at the close of business on the third Business Day following the day when placed in the mail, postage prepaid, certified or registered, addressed to the appropriate party hereto, at the address and/or facsimile numbers of such party set forth below (or at such other address as such party may designate by written notice to the other party in accordance with this Section:

ECRC-08-3387 HEARING EXHIBIT - 00000407

(a) If to Guarantor:

SunPower Corporation
3939 North First Street
San Jose, California 95134
Attention: Chief Financial Officer
Facsimile: (408) 739-7713

(b) If to Owner:

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Attention: [_____]
Facsimile: [_____]

The addresses and facsimile numbers of either party for notices given pursuant to this Guaranty may be changed by means of a written notice given to the other party at least fifteen (15) Business Days prior to the effective date of such change.

Section 6. Miscellaneous Provisions.

(a) Waiver; Remedies Cumulative. No failure on the part of Owner to exercise, and no delay on the part of Owner in exercising, any right or remedy, in whole or in part hereunder shall operate as a waiver thereof. No single or partial exercise of any right or remedy shall preclude any other or further exercise thereof or the exercise of any other right or remedy. No waiver by Owner shall be effective unless it is in writing and such writing expressly states that it is intended to constitute such waiver. Any waiver given by Owner of any right, power or remedy in any one instance shall be effective only in that specific instance and only for the purpose for which given, and will not be construed as a waiver of any right, power or remedy on any future occasion. In addition, Guarantor may not claim that Owner could have avoided or mitigated, in any manner or through any action, the damages resulting from a default of Subsidiary under the Agreement. The rights and remedies of Owner herein provided are cumulative and not exclusive of any rights or remedies provided by law.

(b) Successors and Assigns. This Guaranty shall be binding upon the successors of Guarantor and shall inure to the benefit of Owner and its successors and permitted assigns. Guarantor shall not assign or transfer all or any party of its rights or obligations hereunder without the prior written consent of Owner. Any purported assignment or delegation without such written consent shall be null and void. Owner may assign its rights and obligations hereunder to any assignee of its rights under the Agreement permitted in accordance with the Agreement. No other Persons shall be a third-party beneficiary of, or otherwise benefit by, this Guaranty or have or acquire any rights by reason of this Guaranty.

(c) Amendment. This Guaranty may not be modified, amended, terminated or revoked, in whole or in part, except by an agreement in writing signed by Owner and Guarantor.

(d) Termination and Release. Subject to Section 2(d) hereof, this Guaranty shall remain in effect until the payment in full of the Guaranteed Obligations. No release of this Guaranty shall be valid unless executed by Owner and delivered to Guarantor.

(e) GOVERNING LAW; JURISDICTION.

(i) THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER OR PURSUANT TO THIS GUARANTY SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF FLORIDA, WITHOUT REGARD FOR

ANY PRINCIPLES OF CONFLICTS OF LAW THAT WOULD DIRECT OR PERMIT THE APPLICATION OF THE LAW OF ANY OTHER JURISDICTION.

(ii) THE EXCLUSIVE VENUE FOR ANY ACTION OR PROCEEDING RELATED TO THIS GUARANTY SHALL BE, AND GUARANTOR HEREBY SUBMITS TO THE JURISDICTION OF, THE FEDERAL COURTS OF THE UNITED STATES FOR THE SOUTHERN DISTRICT OF FLORIDA, PROVIDED, THAT IF FOR WHATEVER THE REASON THE FEDERAL COURTS OF THE UNITED STATES FOR THE SOUTHERN DISTRICT OF FLORIDA WILL NOT OR CANNOT HEAR SUCH ACTION OR PROCEEDING, THE EXCLUSIVE VENUE FOR ANY ACTION OR PROCEEDING RELATED TO THIS GUARANTY SHALL BE, AND GUARANTOR HEREBY SUBMITS TO THE JURISDICTION OF, THE COURTS OF THE STATE OF FLORIDA IN PALM BEACH COUNTY. THE PARTIES IRREVOCABLY WAIVE ANY OBJECTION WHICH ANY OF THEM MAY NOW OR HEREAFTER HAVE TO THE BRINGING OF ANY SUCH ACTION OR PROCEEDING IN SUCH RESPECTIVE JURISDICTIONS,

(iii) GUARANTOR WAIVES ANY OBJECTION WHICH IT MAY HAVE TO THE LAYING OF VENUE OF ANY SUCH SUIT, ACTION OR PROCEEDING IN ANY OF SUCH COURTS AND ANY CLAIM THAT ANY SUCH SUIT, ACTION OR PROCEEDING HAS BEEN BROUGHT IN AN INCONVENIENT FORUM, INCLUDING ANY OBJECTION TO THE LAYING OF VENUE BASED ON THE GROUNDS OF FORUM NON CONVENIENS AND ANY OBJECTION BASED ON THE GROUNDS OF LACK OF IN PERSONAM JURISDICTION.

(iv) GUARANTOR IRREVOCABLY CONSENTS TO SERVICE OF PROCESS OUT OF ANY OF THE AFOREMENTIONED COURTS IN ANY MANNER PERMITTED BY SUCH COURTS, INCLUDING REGISTERED OR CERTIFIED MAIL, POSTAGE PREPAID, TO GUARANTOR AT ITS ADDRESS SET FORTH IN THIS AGREEMENT (OR AS OTHERWISE NOTICED TO THE OTHER PARTY PURSUANT TO SECTION 5), IN EACH CASE SUCH SERVICE TO BECOME EFFECTIVE THIRTY (30) DAYS AFTER SUCH MAILING.

(v) GUARANTOR AGREES THAT FINAL JUDGMENT IN ANY SUCH ACTION OR PROCEEDING SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN ANY OTHER JURISDICTION BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY LAW.

(vi) NOTHING IN THIS SECTION SHALL AFFECT THE RIGHT OF OWNER (A) TO SERVE LEGAL PROCESS IN ANY OTHER MANNER PERMITTED BY LAW, OR (B) TO BRING ANY SUIT, ACTION OR PROCEEDING AGAINST THE UNDERSIGNED OR ITS PROPERTIES IN THE COURTS OF ANY OTHER JURISDICTIONS.

(vii) GUARANTOR AND OWNER EACH HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, SUIT OR COUNTERCLAIM ARISING IN CONNECTION WITH THIS GUARANTY. THIS PROVISION IS A MATERIAL INDUCEMENT FOR GUARANTOR AND OWNER TO ENTER INTO THIS GUARANTY.

(f) Survival. All representations and warranties made in this Guaranty and in any other instrument, document, and agreement delivered pursuant hereto or in connection herewith shall survive the execution and delivery of this Guaranty.

(g) Severability. If any provision of this Guaranty is held to be illegal, invalid, or unenforceable under present or future laws, such provision shall be fully severable; this Guaranty shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part of this Guaranty; and the remaining provisions of the Guaranty shall remain in full force and effect and shall not be affected by the illegal, invalid, or unenforceable provision or by its severance from the Guaranty. Furthermore, in lieu of such illegal, invalid or unenforceable provision, there shall

be added automatically as a part of this Guaranty a provision as similar in its terms to such illegal, invalid or unenforceable provision as may be possible and be legal, valid and enforceable.

(h) Information. Owner shall have no obligation to disclose or discuss with Guarantor its assessment, or Guarantor's assessment, of Subsidiary's financial condition. Guarantor acknowledges and agrees that it has adequate means to obtain information from Subsidiary on a continuing basis concerning Subsidiary's financial condition and its ability to perform its obligations under the Agreement, and Guarantor assumes the responsibility for being and keeping informed of Subsidiary's financial condition and of all circumstances bearing upon the risk of nonpayment of the Guaranteed Obligations. Guarantor hereby waives and relinquishes any duty on the part of Owner to disclose any matter, fact or thing relating to the business, operations or conditions of Subsidiary now known or hereafter known by Owner.

(i) Counterparts. Guarantor and Owner acknowledge and agree that this Guaranty may be executed in multiple counterparts, and transmitted via telecopy, each such counterpart (whether transmitted via telecopy or otherwise), when executed, shall constitute an integral part of one and the same agreement.

This Guaranty has been duly executed on behalf of the Guarantor by its authorized officer as of the date first written above.

SUNPOWER CORPORATION

By:_____
Name: _____
Title: _____

ECRC-08-3390 HEARING EXHIBIT - 00000410

Appendix J – Option Pricing

HEARING EXHIBIT - 00000411

Appendix K – Module Warranty

SUNPOWER

SUNPOWER LIMITED WARRANTY FOR PV MODULES

SPR-315E-xxx-x, SPR-300E-xxx-x, SPR-305-xxx-x, SPR-290-xxx-x, SPR-230-xxx-x, SPR-225-xxx-x, SPR-220-xxx-x, SPR-217-xxx-x, SPR-215-xxx-x, SPR-210-xxx-x, SPR-205-xxx-x, SPR-200-xxx-x, SPR-90-xxx-x ("xxx-x" define product variants)

1. Limited Product Warranty – Ten (10) Year Repair, Replacement or Refund Remedy

SunPower Corporation with offices at 3939 North First Street, San Jose, CA 95134 ("SunPower") warrants that for ten (10) years from the date of delivery, its Photovoltaic modules ("PV modules") shall be free from defects in materials and workmanship under normal application, installation, use and service conditions. If the PV modules fail to conform to this warranty, then for a period ending ten (10) years from date of delivery to the original end-customer ("the Customer"), SunPower will, at its option, either repair or replace the product, or refund the purchase price as paid by the Customer ("Purchase Price"). The repair, replacement or refund remedy shall be the sole and exclusive remedy provided under the Limited Product Warranty and shall not extend beyond the ten (10) year period set forth herein. This Limited Product Warranty does not warrant a specific power output, which shall be exclusively covered under clause 2 hereinafter (Limited Power Warranty).

2. Limited Power Warranty

a) SunPower additionally warrants: If, within twelve (12) years from date of delivery to the Customer any PV module(s) exhibits a power output less than 90% of the Minimum Peak Power[1] as specified at the date of delivery in SunPower's Product datasheet, provided that such loss in power is determined by SunPower (at its sole and absolute discretion) to be due to defects in material or workmanship SunPower will replace such loss in power by either providing to the Customer additional PV modules to make up such loss in power or by providing monetary compensation equivalent to the cost of additional PV modules required to make up such loss in power or by repairing or replacing the defective PV modules, at the option of SunPower

b) SunPower additionally warrants: If, within twenty five (25) years from date of delivery to the Customer any PV module(s) exhibits a power output less than 80% of the Minimum Peak Power[1] as specified at the date of delivery in SunPower's Product datasheet, provided that such loss in power is determined by SunPower (at its sole and absolute discretion) to be due to defects in material or workmanship SunPower will replace such loss in power by either providing to the Customer additional PV modules to make up such loss in power or by providing monetary compensation equivalent to the cost of additional PV modules required to make up such loss in power or by repairing or replacing the defective PV modules, at the option of SunPower.

3. Exclusions and limitations

a) Warranty claims must in any event be filed within the applicable Warranty period.

b) Warranty claims may only be made by, or on the behalf of, the original end customer or a person to whom title has been transferred for the PV Modules.

c) The Limited Warranties do not apply to any of the following:

1. PV modules which in SunPower's absolute judgment have been subjected to: misuse, abuse, neglect or accident; alteration, improper installation, application or removal (including but not

---

[1] *"Minimum Peak Power" = Peak power minus the Peak power tolerance (as specified in SunPower's Product datasheet). "Peak power" is the power in peak watts that a PV module generates at STC (Standard Test conditions: Irradiance of 1000 W/m², light spectrum AM 1.5g and a cell temperature of 25 degrees C)*

limited to installation, application or removal by any party other than a SunPower authorized dealer; non-observance of SunPower's installation, users and/or maintenance instructions; repair or modifications by someone other than an approved service technician of SunPower; power failure surges, lightning, flood, fire, accidental breakage or other events outside SunPower's control.

2. Cosmetic defects stemming from normal wear and tear of PV module materials.
3. PV modules installed in locations, which in SunPower's absolute judgment may be subject to direct contact with salt water.

d) The Limited Warranties do not cover any transportation costs for return of the PV modules, or for reshipment of any repaired or replaced PV modules, or cost associated with installation, removal or reinstallation of the PV modules.

e) When used on a mobile platform of any type, the Limited Power Warranty, applying to any of the PV modules shall be limited to twelve (12) years as per the provisions of clause 2(a) hereof.

f) Warranty claims will not apply if the type or serial number of the PV modules is altered, removed or made illegible.

4. Limitation of Warranty Scope

SUBJECT TO THE LIMITIATIONS UNDER APPLICABLE LAW, THE LIMITED WARRANTIES SET FORTH HEREIN ARE EXPRESSLY IN LIEU OF AND EXCLUDE ALL OTHER EXPRESS OR IMPLIED WARRANTIES, INCLUDING BUT NOT LIMITED TO WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR PARTICULAR PURPOSE, USE, OR APPLICATION, AND ALL OTHER OBLIGATIONS OR LIABILITIES ON THE PART OF SUNPOWER, UNLESS SUCH OTHER WARRANTIES, OBLIGATIONS OR LIABILITIES ARE EXPRESSLY AGREED TO IN WRITING SIGNED AND APPROVED BY SUNPOWER. SUNPOWER SHALL HAVE NO RESPONSIBILITY OR LIABILITY WHATSOEVER FOR DAMAGE OR INJURY TO PERSONS OR PROPERTY OR FOR OTHER LOSS OR INJURY RESULTING FROM ANY CAUSE WHATSOEVER ARISING OUT OF OR RELATED TO THE PRODUCT, INCLUDING, WITHOUT LIMITATION, ANY DEFECTS IN THE MODULE, OR FROM USE OR INSTALLATION. UNDER NO CIRCUMSTANCES SHALL SUNPOWER BE LIABLE FOR INCIDENTAL, CONSEQUENTIAL OR SPECIAL DAMAGES, HOWSOEVER CAUSED. LOSS OF USE, LOSS OF PROFITS, LOSS OF PRODUCTION, LOSS OF REVENUES ARE THEREFORE SPECIFICALLY BUT WITHOUT LIMITATION EXCLUDED.

SUNPOWER'S AGGREGATE LIABILITY, IF ANY, IN DAMAGES OR OTHERWISE, SHALL NOT EXCEED THE PURCHASE PRICE PAID TO SUNPOWER BY THE CUSTOMER, FOR THE UNIT OF PRODUCT OR SERVICE FURNISHED OR TO BE FURNISHED, AS THE CASE MAY BE, WHICH GAVE RISE TO THE WARRANTY CLAIM.

SOME STATES DO NOT ALLOW LIMITATIONS ON IMPLIED WARRANTIES OR THE EXCLUSION OF DAMAGES SO THE ABOVE LIMITATIONS OR EXCLUSIONS MAY NOT APPLY TO YOU.

5. Obtaining Warranty Performance

If you feel you have a justified claim covered by this Limited Warranty, immediately notify the (a) Installer, who sold the PV-modules, or (b) any authorized SunPower distributor, of the claim in writing, or (c) send such notification to SunPower Corporation, 3939 North First Street, San Jose, CA 95134, directly. In addition, please enclose evidence of the date of delivery of the PV module. If applicable, your installer or distributor will give advice on handling the claim. If further assistance is required, please write to SunPower for instructions. The return of any PV-modules will not be accepted unless prior written authorization has been given by SunPower.

Appendix L – O&M Manual

HEARING EXHIBIT - 00000415

Appendix M – FPL Permits

HEARING EXHIBIT - 00000416

DeSoto Solar Project
List of Permits/Authorizations/Action Items

APPENDIX M
FPL Permits

	Task	Responsible Agency	Responsible Party	Target Completion Date	Comments
1	Environmental Resource Permit	Water Management District	FPL	12/1/08	ACOE not required because no impact to wetlands.
2	Conduct Threatened and Endangered (T&E) Species Survey	USFWS	FPL	6/24/08	Complete.
3	Environmental Assesment and Findings of No Significant impact	NASA	FPL	6/24/08	Complete.
4	Federal, State and Local easements	site specific	FPL	TBD	
5	Determination of 'no hazard to air navigation'	FAA	FPL	6/18/08	Complete.
6	Spill Prevention Control and Counter Measures (SPCC) Plan	EPA	FPL	TBD	Post Construction if needed.
7	Environmental Conditions Report	NASA	NASA	TBD	By NASA to document existing conditions.
8	Traffic Analysis Study	FDOT	FPL	TBD	
9	Interconnection Right-of-Way	FDOT	FPL	TBD	
10	Water well permits (consumptive)	County or WMD	FPL	TBD	N/A for Construction. Needed for Operation.

ECRC-08-3466
HEARING EXHIBIT - 00000417

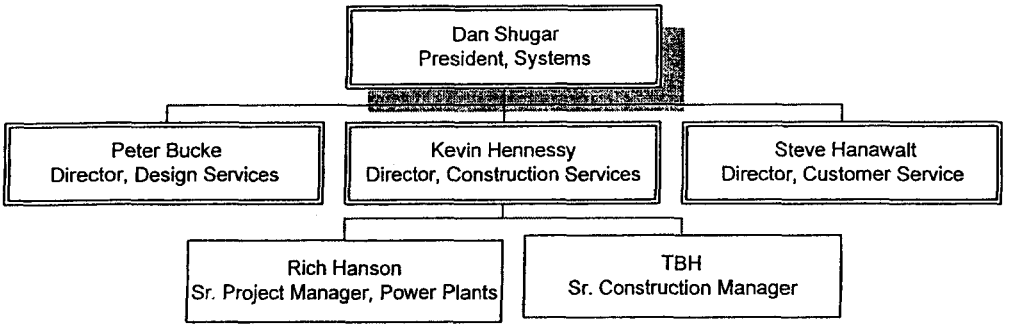
Appendix N – Termination Payment Schedule

HEARING EXHIBIT - 00000418

Appendix O – Project Management Team

APPENDIX O

Project Management Team



TBH – To be hired, subject to the approval requirements of Section 3.12.1 of the Agreement

Biographical Information:

Daniel S. Shugar, President, SunPower Systems

Mr. Shugar leads Supply Chain, Manufacturing, Product Development, and Project Engineering and Construction. Since January 1996, Mr. Shugar has overseen the installation of over 200 MW of solar PV projects. He has been active in solar power since 1988. Mr. Shugar has a B.S. in Electrical Engineering from Rensselaer Polytechnic University, and an MBA from Golden Gate University in San Francisco.

Kevin Hennessy, Director, Construction Services

Mr. Hennessy is a Professional Engineer with over 25 years of commercial construction experiences. He has extensive knowledge of design and construction methods of all types of building systems and has developed projects all over the globe. He is responsible for the Design and Construction groups in the Systems Group at SunPower. This team has been responsible for implementation of the largest Solar PV Energy projects throughout the world, including several projects over 20MW's. Kevin is a California licensed Civil Engineer and has a M.S. in Civil Engineering from Stanford University.

Peter Buecke, Director Design Services

Mr. Buecke is an architect who has led the design and construction division for several national home builders. He is responsible for all activities related to the design and engineering of large ground-mounted and roof-top solar projects. He has over 20 years of experience on project planning with success in setting and meeting project design milestones. He has a B.S in Design from the College of Architecture at Arizona State University.

Steve Hanawalt, Director, Customer Service

Mr. Hannawalt leads the Customer Service and O&M Group for SunPower Systems. His energy facility operations and management experience includes start-up engineering, performance engineering, operations management, and asset optimization. Prior to joining SunPower, he was Vice President of

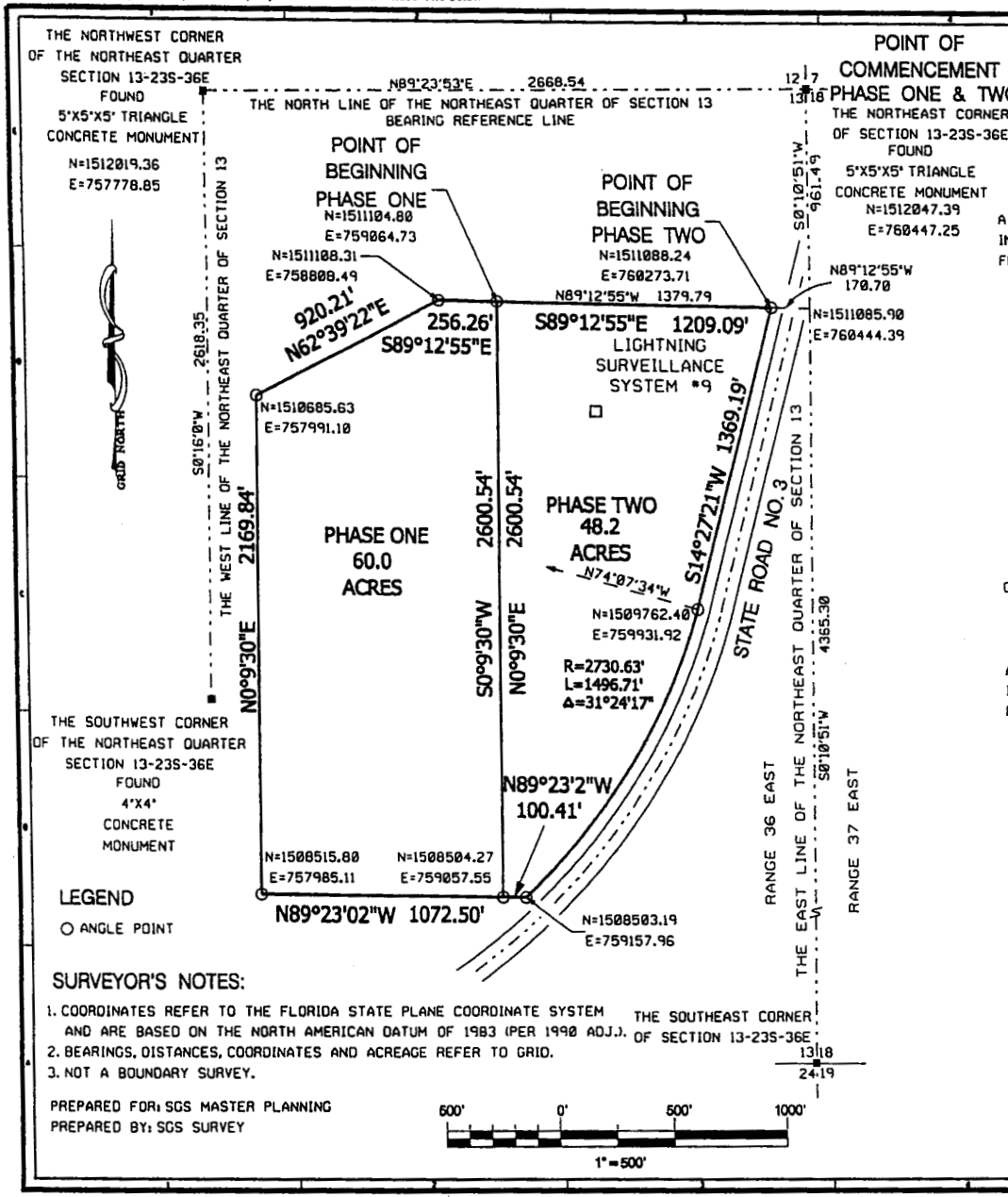
Plant Optimization at Calpine Corporation, a large independent power producer. In that capacity his group provided the 25,000 MW fleet with system commissioning services, performance and reliability engineering, and real-time performance monitoring and diagnostic services. Plant Optimization provided the performance, reliability, and cost structure inputs to System Dispatch to optimize the economic dispatch of the generating units. Mr. Hanawalt received his B.S. in Mechanical Engineering from the University of California, Berkeley and is currently pursuing his MBA.

Rich Hanson, Senior Project Manager

Mr. Hanson has been involved as a project manager of utility size power plants since joining SunPower Corp . Most recently he was responsible for completing a 14 MW ground mounted tracking system at Nellis Air Force Base in Las Vegas, NV. Prior to joining SunPower, Rich was Director of Construction for a Construction Management firm in the California Central Valley, specializing in design/build management of medical office buildings, airport construction, and regional shopping centers.

Appendix P – Legal Description of Property Site

Appendix P - Legal Description of Property Site - Described in Phase One below



SKETCH OF DESCRIPTION
F.P.L. SOLAR PHOTOVOLTAIC

PHASE ONE

A PARCEL OF LAND LYING ON THE JOHN F. KENNEDY SPACE CENTER, IN SECTION 13, TOWNSHIP 23 SOUTH, RANGE 36 EAST, BREVARD COUNTY, FLORIDA, AND BEING MORE FULLY DESCRIBED AS FOLLOWS:

COMMENCE AT THE NORTHEAST CORNER OF SECTION 13, SAID CORNER HAVING A FLORIDA STATE PLANE COORDINATE VALUE OF NORTH 1512047.39 AND EAST 760447.25 (NAD83), AS DERIVED FROM A NATIONAL GEODETIC SURVEY TRIANGULATION STATION 'COURTENAY 1953'; THENCE S00°10'51"W ALONG THE EAST LINE OF THE NORTHEAST QUARTER OF SAID SECTION 13 FOR A DISTANCE OF 961.49 FEET TO A POINT; THENCE N89°12'55"W FOR A DISTANCE OF 1379.79 FEET TO THE POINT OF BEGINNING; THENCE S0°9'30"W FOR A DISTANCE OF 2600.54 FEET TO A POINT; THENCE N89°23'02" W FOR A DISTANCE OF 1072.50 FEET TO A POINT; THENCE N0°9'30" E FOR A DISTANCE OF 2169.84 FEET TO A POINT; THENCE N62°39'22" E FOR A DISTANCE OF 920.21 FEET TO A POINT; THENCE S89°12'55" E FOR A DISTANCE OF 256.26 FEET TO THE POINT OF BEGINNING.

CONTAINING 60.0 ACRES MORE OR LESS.

PHASE TWO

A PARCEL OF LAND LYING ON THE JOHN F. KENNEDY SPACE CENTER, IN SECTION 13, TOWNSHIP 23 SOUTH, RANGE 36 EAST, BREVARD COUNTY, FLORIDA, AND BEING MORE FULLY DESCRIBED AS FOLLOWS:

COMMENCE AT THE NORTHEAST CORNER OF SECTION 13, SAID CORNER HAVING A FLORIDA STATE PLANE COORDINATE VALUE OF NORTH 1512047.39 AND EAST 760447.25 (NAD83), AS DERIVED FROM NATIONAL GEODETIC SURVEY TRIANGULATION STATION 'COURTENAY 1953'; THENCE S00°10'51"W ALONG THE EAST LINE OF THE NORTHEAST QUARTER OF SAID SECTION 13 FOR A DISTANCE OF 961.49 FEET TO A POINT; THENCE N89°12'55"W FOR A DISTANCE OF 170.70 FEET TO THE POINT OF BEGINNING; THENCE S14°27'21"W FOR A DISTANCE OF 1369.19 FEET TO THE BEGINNING OF A CURVE CONCAVE TO THE NORTHWEST HAVING A RADIUS OF 2730.63 FEET AND TO WHICH A RADIAL LINE BEARS N74°07'34"W; THENCE SOUTHWESTERLY 1496.71 FEET ALONG THE ARC OF SAID CURVE THROUGH A CENTRAL ANGLE OF 31°24'17" TO A NON-TANGENT LINE; THENCE N89°23'02"W ALONG SAID NON-TANGENT LINE FOR A DISTANCE OF 100.41 FEET TO A POINT; THENCE N0°9'30" E FOR A DISTANCE OF 2600.54 FEET TO A POINT; THENCE S89°12'55"E FOR A DISTANCE OF 1209.09 FEET TO THE POINT OF BEGINNING.

CONTAINING 48.2 ACRES MORE OR LESS.

SGS
SPACE GATEWAY SUPPORT
SURVEY SERVICES
KSWA, BOS-3208
KENNEDY SPACE CENTER, FLORIDA 32815

HAZARDOUS MATERIALS: AFTER SURVEY ARE THE KNOWN HAZARDOUS MATERIALS RELATED TO THIS PROJECT. REFER TO ENVIRONMENTAL REPORT FOR ADDITIONAL INFORMATION AND RECOMMENDATIONS.

SUSPECTED LEAD YES NO
SUSPECTED ASBESTOS

THE CONTRACTOR EXECUTING THE SURVEYOR'S CONTRACT SHALL BE RESPONSIBLE FOR ALL NECESSARY PRECAUTIONS REGARDING HAZARDOUS MATERIAL THAT PERSONNEL UNDER HIS CONTROL MAY ENCOUNTER, INCLUDING BUT NOT LIMITED TO, EMPLOYEE TRAINING, PROTECTIVE CLOTHING, AND EQUIPMENT. THE CONTRACTOR SHALL ALSO COMPLY WITH ALL APPLICABLE FEDERAL, STATE AND LOCAL LAWS AND REGULATIONS AND SHALL ESTABLISH AND MAINTAIN THE EMERGENCY PROCEDURES FOR EXPOSURES.

SPECIFICATIONS:
THESE DRAWINGS ARE PART OF A CONTRACT DOCUMENT AND SHOULD BE READ TOGETHER WITH THE SPECIFICATIONS AND ALL OTHER CONTRACT DOCUMENTS.

NOTICE:
THESE DRAWINGS ARE PART OF A COPYRIGHTED DOCUMENT AND SHALL NOT BE USED WITHOUT WRITTEN AUTHORIZATION FROM SGS.

REVISIONS:

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
JOHN F. KENNEDY SPACE CENTER, NASA
KENNEDY SPACE CENTER, FLORIDA

F.P.L SOLAR PHOTOVOLTAIC
LAND DESCRIPTION

DWN NO:
CAD DWG NO:
CAD FILE NO:

NAME	SIGNATURE	DATE
DRN		5-13-08
CHK		
APP		
APP		
APP		

LEGAL DESCRIPTION

SHT 1 of 1

ECRC-08-3473 HEARING EXHIBIT - 00000423

Appendix Q – Form of Progress Achievement Certificate

HEARING EXHIBIT - 00000424

APPENDIX Q
FORM OF PROGRESS ACHIEVEMENT CERTIFICATE

(COVER LETTER)

Date: _____

Mr. _____
[CONTRACTOR]
Project Manager

Reference: [CONTRACTOR] Job No. _____
Subject: Progress Achievement Certification Letter No. _____

Dear Mr. _____:

[CONTRACTOR] certifies that the activities listed in "Progress Certificate No. ____" attached hereto have the percentage of completion provided therein. "Progress Certificate No. ____" is offered as evidence of such percentage of completion.

Very Truly Yours,

[CONTRACTOR] Project Manager

Attachment: "Progress Certificate No. _____"

ECRC-08-3475 HEARING EXHIBIT - 00000425

APPENDIX Q
FORM OF PROGRESS ACHIEVEMENT CERTIFICATE
(continued)

(PROGRESS CERTIFICATE)

Date: _____

To: [FPL] Project Manager

_____

From: [CONTRACTOR] Project Manager

_____

Subject: Progress Certificate No. _____

This is to certify that, as of _____, the attached activities have the following percentages of completion.

SEE ATTACHED SCHEDULE OF VALUES FOR DETAIL

SIGNED: _____ DATE: _____
CONTRACTOR PROJECT MANAGER

ECRC-08-3476 HEARING EXHIBIT - 00000426

Appendix R – Form of Contractor Certificate for Final Waiver of Liens

APPENDIX R

FORM OF CONTRACTOR CERTIFICATE FOR FINAL WAIVER OF LIENS

This CONTRACTOR'S FULL LIEN WAIVER AND RELEASE ("Contractor's Full Lien Waiver and Release") is made by SunPower Corporation, Systems, a Delaware corporation ("Contractor"), on behalf of itself, its successors and assigns, and those acting by or through any of the foregoing, for and in consideration of [AMOUNT OF FINAL PAYMENT REQUEST] DOLLARS ($[_____]) and other good and valuable consideration, in hand paid, the receipt and sufficiency of which are hereby acknowledged, as full and final payment on account of all labor, services, materials, equipment and other work performed for Florida Power & Light Company ("Owner"), in connection with the construction of a solar photovoltaic electric generation facility, and all services and utilities related thereto, in Brevard County, Florida (such facility, together with the property on which such facility is located, the "Project"), pursuant to that certain TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT FOR SOLAR PHOTOVOLTAIC GENERATING FACILITY, dated as of July [__], 2008, between Owner and Contractor, as the same may be amended from time to time (the "Agreement").

Contractor does hereby unconditionally and irrevocably waive, release, remise, relinquish and quit-claim all actions, claims, demands, liens, lien rights and claims of lien, of any kind whatsoever, which Contractor ever had, now has, or may have in the future, known or unknown, against the Project or against Owner, its parents, subsidiaries and affiliates, at all tiers, and its and their insurers, sureties, employees, officers, directors, representatives, shareholders, agents, and all parties acting for any of them related to or arising from the Project (collectively, the "Released Entities"), including, without limitation, all claims related to, in connection with, or arising out of, all facts, acts, events, circumstances, changes or extra work, constructive or actual delays or accelerations, interferences and the like, which have occurred or may be claimed to have occurred.

The Contractor warrants and represents that (a) the Contractor has not assigned or pledged any rights or claims in any amount due or to become due from Owner related to or arising from the Project; (b) payment has been or will be made to all subcontractors, laborers and material suppliers, at all tiers, for all labor, services, materials and equipment furnished by or through the Contractor for the Project, including all payroll taxes and contributions required to be made; (c) no claims from subcontractors, vendors, mechanics or materialmen against the Released Entities have been submitted to Contractor with respect to the Project or remain unsatisfied as of the date hereof; (d) no mechanics' or materialmen's liens have been filed with respect to the Project that have not been discharged or for which a bond has not been posted in accordance with the Agreement; (e) payment of all amounts due has been made to all consultants, employees, subcontractors, laborers and material suppliers, at all tiers, and all other entities, for all labor, services, materials and equipment furnished by or through Contractor for the Project, including, without limitation, all payroll taxes and contributions required to be made and all wages, overtime pay, premium pay, holiday pay, sick pay, personal leave pay, severance pay, fees, fringe benefits, commissions and reimbursable expenses required to be paid and all deductions for dues, fees or contributions required to be made in connection with all collective bargaining agreements in existence, if any, which affect any worker(s) providing services for the Project; and (f) all contracts with consultants and subcontractors employed, used or engaged by Contractor in connection with the Project have been completed or have been terminated.

ECRC-08-3478 HEARING EXHIBIT - 00000428

The Contractor agrees to defend, indemnify and hold the Released Entities harmless from and against any and all actions, causes of action, losses or damages of whatever kind, including, without limitation, reasonable attorneys' fees and costs in arbitration and at the pre-trial, trial and appellate levels, which the Released Entities may suffer by reason of (a) any claim made against the Project or any of the Released Entities relating to labor, services, materials or equipment furnished by or through the Contractor related to or arising from the Project, or (b) any breach of any representation or warranty made by the Contractor to Owner related to or arising from the Project, including the representations and warranties included herein, any false statement made in this Contractor's Full Lien Waiver and Release or any misrepresentation or omission made to Owner by the Contractor.

The Contractor acknowledges and agrees that (a) Owner is relying upon the representations and warranties made herein as a material inducement for Owner to make payment to the Contractor; (b) this Contractor's Full Lien Waiver and Release is freely and voluntarily given by the Contractor, and the Contractor has had the advice of counsel in connection herewith and is fully informed as to the legal effects of this Contractor's Full Lien Waiver and Release, and the Contractor has voluntarily accepted the terms herein for the consideration recited above; and (c) the tendering of payment by Owner and the receipt of payment and the execution of this Contractor's Full Lien Waiver and Release by the Contractor shall not, in any manner whatsoever, release the Contractor from (i) its continuing obligations with respect to the completion of any work at the Project that remains incomplete, including warranty work or guaranty work, or the correction of defective or non-conforming work; (ii) any contractual, statutory or common law obligations of the Contractor with respect to the Released Entities related to or arising from the Project; or (iii) any other obligations of the Contractor with respect to Released Entities related to or arising from the Project.

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SIGNATURES APPEAR ON FOLLOWING PAGE.]

ECRC-08-3479 HEARING EXHIBIT - 00000429

Dated this ___day of _____, 200__.

SUNPOWER CORPORATION, SYSTEMS:

WITNESSES:

_____
Name:_____

_____
Name:_____

By: _____
Name:_____
Title:_____
Address:_____
_____
_____

NOTARIAL ACKNOWLEDGMENT

STATE OF _____)
) ss:
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 200__, by _____, the _____ of SunPower Corporation, Systems, a Delaware corporation, who executed the foregoing instrument on behalf of said corporation, and who is personally known to me or who produced _____ as identification.

_____
Name: _____
Notary Public, State of [Florida]
[If notarized in a State other than Florida, Signatory shall comply with the notary requirements of such State.]
Commission No._____
My Commission expires: _____
(Seal)

Appendix R-1 – Form of Subcontractor Certificate for Final Waiver of Liens

HEARING EXHIBIT - 00000431

APPENDIX R-1

FORM OF SUBCONTRACTOR CERTIFICATE FOR FINAL WAIVER OF LIENS

This SUBCONTRACTOR'S FULL LIEN WAIVER AND RELEASE ("Subcontractor's Full Lien Waiver and Release") is made by [_____], a [_____] (the "Releasor"), subcontractor to SunPower Corporation, Systems, a Delaware corporation ("Contractor"), on behalf of Releasor, its successors and assigns, and those acting by or through any of the foregoing, for and in consideration of the sum of Ten and No/100 DOLLARS ($10.00) and other good and valuable consideration, in hand paid, the receipt and sufficiency of which are hereby acknowledged, as full and final payment on account of all labor, services, materials, equipment and other work furnished in connection with the construction of a solar photovoltaic electric generation facility, and all services and utilities related thereto, in Brevard County, Florida (such facility, together with the property on which such facility is located, the "Project") by Contractor on behalf of Florida Power & Light Company, a Florida corporation ("Owner").

Releasor does hereby unconditionally and irrevocably waive, release, remise, relinquish and quit-claim all actions, claims, demands, liens, lien rights and claims of lien, of any kind whatsoever, which Releasor ever had, now has, or may have in the future, known or unknown, against the Project, or against Owner or Contractor, their partners, parents, subsidiaries and affiliates, at all tiers, and their insurers, sureties, employees, officers, directors, representatives, shareholders, agents, and all parties acting for any of them related to or arising from the Project (collectively, the "Released Entities"), including, without limitation, all claims related to, in connection with, or arising out of, all facts, acts, events, circumstances, changes or extra work, constructive or actual delays or accelerations, interferences and the like, which have occurred or may be claimed to have occurred.

The Releasor warrants and represents that (a) the Releasor has not assigned or pledged any rights or claims in any amount due or to become due from Contractor related to or arising from the Project; (b) payment has been or will be made to all of its subcontractors, laborers and material suppliers, at all tiers, for all labor, services, materials and equipment furnished by or through the Releasor for the Project, including all payroll taxes and contributions required to be made; (c) no claims from any of its subcontractors, vendors, mechanics or materialmen against the Released Entities have been submitted to Releasor with respect to the Project or remain unsatisfied as of the date hereof; (d) no mechanics' or materialmen's liens have been filed with respect to the Project that have not been discharged; (e) payment of all amounts due has been made to all consultants, employees, subcontractors, laborers and material suppliers, at all tiers, and all other entities, for all labor, services, materials and equipment furnished by or through Releasor for the Project, including, without limitation, all payroll taxes and contributions required to be made and all wages, overtime pay, premium pay, holiday pay, sick pay, personal leave pay, severance pay, fees, fringe benefits, commissions and reimbursable expenses required to be paid and all deductions for dues, fees or contributions required to be made in connection with all collective bargaining agreements in existence, if any, which affect any worker(s) providing services for the Project; and (f) all contracts with consultants and subcontractors employed, used or engaged by Releasor in connection with the Project have been completed or have been terminated.

The Releasor agrees to defend, indemnify and hold the Released Entities harmless from and against any and all actions, causes of action, losses or damages of whatever kind, including, without limitation, reasonable attorneys' fees and costs in arbitration and at the pre-trial, trial and

ECRC-08-3482 HEARING EXHIBIT - 00000432

appellate levels, which the Released Entities may suffer by reason of (a) any claim made against the Project or any of the Released Entities relating to labor, services, materials or equipment furnished by or through the Releasor related to or arising from the Project, or (b) any breach of any representation or warranty made by the Releasor to the Released Entities related to or arising from the Project, including the representations and warranties included herein, any false statement made in this Subcontractor's Full Lien Waiver and Release, or any misrepresentation or omission made to the Released Entities by the Releasor.

The Releasor acknowledges and agrees that (a) the Contractor and Owner are relying upon the representations and warranties made herein as a material inducement for the Contractor or Owner to make payment to the Releasor; (b) this Subcontractor's Full Lien Waiver and Release is freely and voluntarily given by the Releasor and the Releasor has had the advice of counsel in connection herewith and is fully informed as to the legal effects of this Subcontractor's Full Lien Waiver and Release and the Releasor has voluntarily accepted the terms herein for the consideration recited above; and (c) the tendering of payment by the Contractor and the receipt of payment and the execution of this Subcontractor's Full Lien Waiver and Release by the Releasor shall not, in any manner whatsoever, release the Releasor from (i) its continuing obligations with respect to the completion of any work at the Project that remains incomplete, including warranty work or guaranty work, or the correction of defective or non-conforming work related to or arising from the Project; (ii) any contractual, statutory or common law obligations of the Releasor with respect to any of the Released Entities related to or arising from the Project; or (iii) any other obligations of the Releasor with respect to any of the Released Entities related to or arising from the Project.

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SIGNATURES APPEAR ON FOLLOWING PAGE.]

Dated this ___day of _____, 200__.

WITNESSES:

_____
Name:_____

_____
Name:_____

Subcontractor:

By: _____
Name:_____
Title:_____

Address:_____
_____
_____

NOTARIAL ACKNOWLEDGMENT

STATE OF _____)
) ss:
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 200__, by _____, the _____ of_____, a _____, who executed the foregoing instrument on behalf of said corporation, and who is personally known to me or who produced _____ as identification.

_____
Name: _____
Notary Public, State of [Florida]
[If notarized in a State other than Florida, Signatory shall comply with the notary requirements of such State.]
Commission No._____
My Commission expires: _____
(Seal)

Appendix S – Form of Request for Change Order

HEARING EXHIBIT - 00000435

APPENDIX S
FORM OF REQUEST FOR CHANGE ORDER
CHANGE ORDER FORM
Florida Power & Light Company
CONTRACT CHANGE ORDER NO. _____

FPL

Contractor: SunPower Corporation, Systems Title: Date:

CONTRACT CHANGE: (Detail)	Amount (Circle Credits)
This Change Order No. [___], effective [_____], is issued to amend the *Turnkey Engineering, Procurement and Construction Agreement for Solar Photovoltaic Generating Facility Between Florida Power & Light Company and SunPower Corporation, Systems dated July [__], 2008* (the "Agreement") as specified below. The initial capitalized terms used herein, unless otherwise defined in this Change Order, shall have the meanings ascribed to them in the Agreement.	
Contract Start Date: No change **Contract Completion Date:** No change	**Total Authorized Amount This Change Order**

Schedule of Prices: Lump Sum Fixed Price

WORK/SERVICE START DATE: **WORK/SERVICE END DATE:**

It is hereby understood that, if this Change Order is executed by FPL, the Contractor shall implement the above-referenced change(s). If this Change Order is executed by FPL, the changes to the Work, Contract Price, time requirements and/or any other provisions of the Agreement described in this document are considered an amendment to the Agreement. Except as otherwise set forth in this document, the change(s) described in this document do not relieve FPL or the Contractor of their responsibilities described in the Agreement. If this Change Order is executed by FPL, this document constitutes a full and complete settlement with respect to change(s) to the Work, Contract Price, time requirements and/or any other provisions of the Agreement described in this document, including the settlement of compensation to Contractor, for the change(s) described in this document.

_____
Project Manager

COST HISTORY

Original Contract Price $ _____
Total Previous Changes Auth. _____
This Change (Net Amount) _____
☐ Firm ☐ Estimate
Total Contract Price (Including this change) $ _____
Could this CCO Impact Other Contracts? ☐ Yes ☐ No

Primary Cause of Change (Check One)

☐ Variance from Quantity Estimate
☐ Regulatory Requirements
☐ Construction Changes
☐ Engineering Changes
☐ Other Department Requests
☐ Vendor Caused (Identify Back Charges)
☐ Constructability
☐ Other (Specify) _____

SCHEDULE

☐ Change Does Not Affect Guaranteed Provisional Acceptance Date

☐ Change Wll Affect Guaranteed Provisional Acceptance Date

Accepted by:

Signature: _____
Name (Print) _____
Title (Print) _____
Date: _____

Authorization:
FLORIDA POWER & LIGHT COMPANY

Signature: _____
Name (Print) _____
Title (Print) _____
Date: _____

ECRC-08-3486 HEARING EXHIBIT - 00000436

APPENDIX T

Intentionally Deleted

HEARING EXHIBIT - 00000437

Appendix U – Form of Letter of Credit

HEARING EXHIBIT - 00000438

WELLS FARGO BANK, N.A.
TRADE SERVICES DIVISION - STANDBY LETTER OF CREDIT UNIT
One Front Street, 21st Floor, San Francisco, California 94111
Phone: (800) 798-2815 Option 1. E-Mail: sftrade@wellsfargo.com

APPENDIX U

Form of Letter of Credit

Florida Power & Light Company
700 Universe Blvd
Juno Beach, FL
Attention: Project General Manager

Re: Irrevocable Standby Letter of Credit No. _____

Gentlemen:

We hereby establish in your favor this Irrevocable Standby Letter of Credit No. _____ (the "Letter of Credit") for the account of SunPower Corporation, Systems, a Delaware corporation ("Contractor"), effective immediately and expiring on December 31, 2009.

We have been informed by the Applicant, but do not independently verify, that this Letter of Credit is issued pursuant to the terms of that certain Turnkey Engineering, Procurement and Construction Agreement for Solar Photovoltaic Generating Facility dated as of July 9, 2008, between Florida Power & Light Company, a Florida corporation ("Beneficiary"), and Contractor, as the same may be amended (the "Agreement").

1. Stated Amount. The amount of funds available for drawing under this Letter of Credit shall be U.S. $1,145,600 (one million one hundred forty-five thousand six hundred United States Dollars) (the "Stated Amount").

2. Drawings. A drawing hereunder may be made by you on any Business Day on or prior to the date this Letter of Credit expires by delivering to Wells Fargo Bank, N.A., at any time during its business hours on such Business Day, at One Front Street 21st Floor, San Francisco, CA 94111, a copy of this Letter of Credit together with (i) a Draw Certificate executed by an authorized person substantially in the form of Attachment A hereto (the "Draw Certificate"), appropriately completed and purportedly signed by your authorized officer and (ii) your draft substantially in the form of Attachment B hereto (the "Draft"), appropriately completed and purportedly signed by your authorized officer. Partial drawings and multiple presentations may be made under this Letter of Credit. Draw Certificates and Drafts under this Letter of Credit may be sent by overnight delivery or courier to Wells Fargo Bank, N.A., at its address set forth above Attention: Standby Letter of Credit Unit. Drawings may also be presented to us via telefacsimile to our telefacsimile no. (415) 296-8905 (each such drawing, a "Fax Drawing"); *provided however* that you confirm our receipt of any Fax Drawing by telephone to our telephone no. 1-800-798-2815 (option 1). In the event of a presentation by facsimile transmission, the original of such documents shall be sent to address set forth in the preceding sentence, as aforesaid, by overnight courier for receipt by us within one (1) Business Day of the date of such facsimile transmission.

3. Time and Method for Payment. We hereby agree to honor a drawing hereunder made in compliance with this Letter of Credit by transferring in immediately available funds the amount

specified in the Draft delivered to us in connection with such drawing to such account at such bank in the United States as you may specify in your Draw Certificate. If the Draw Certificate is presented to us at such address by 10:00 a.m., California time on any Business Day, payment will be made not later than 3:00 p.m., California time on the next day and if such Draw Certificate is so presented to us after 10:00 a.m., California time on any Business Day, payment will be made on the second Business Day. In clarification, we agree to honor the Draw Certificate upon receipt thereof, without regard to the truth or falsity of the assertions made therein.

4. Non-Conforming Demands. If a demand for payment made by you hereunder does not, in any instance, conform to the terms and conditions of this Letter of Credit, we shall give you prompt notice that the demand for payment was not effected in accordance with the terms and conditions of this Letter of Credit, stating the reasons therefore and that we will upon your instructions hold any documents at your disposal or return the same to you. Upon being notified that the demand for payment was not effected in conformity with this Letter of Credit, you may correct any such non-conforming demand.

5. Expiration. This Letter of Credit shall automatically expire at the close of business on December 31, 2009 or such earlier date on which we receive a Cancellation Certificate in the form of Attachment C hereto purportedly executed by your authorized officer upon which this Letter of Credit shall be cancelled (the "Expiration Date").

6. Rollover. The Letter of Credit shall be deemed automatically extended without amendment for one additional period of one (1) year from the present expiration date, unless at least sixty (60) Business Days prior to such expiration date we shall notify you by registered mail or overnight courier at the above address (or such other address as may be designated by you as contemplated by numbered paragraph 9) that we elect not to consider this Letter of Credit extended for such additional one year period; provided, however, in any event this Letter of Credit shall expire on December 31, 2010.

7. Business Day. As used herein, "Business Day" shall mean any day on which commercial banks are not authorized or required to close in the State of California.

8. Governing Law. Except as far as otherwise expressly stated herein, this Letter of Credit is subject to the International Standby Practices ("ISP98"), except for Rule 3:14(a), International Chamber of Commerce Publication No. 590. As to matters not addressed by the ISP98, this Letter of Credit shall be governed by and construed in accordance with the laws of the State of California and applicable U.S. federal law.

9. Notices. All communications to you in respect of this Letter of Credit shall be in writing and shall be delivered to the address shown for you herein before or such other address as may from time to time be designated by you in a written notice to us. All documents to be presented to us hereunder and all other communications to us in respect of this Letter of Credit, which other communications shall be in writing, shall be delivered to the address for us indicated on the signature page hereof, or such other address as may from time to time be designated by us in a written notice to you.

10. Irrevocability. This Letter of Credit is irrevocable.

11. Transferability. We shall not authorize any transfer of this Letter of Credit until a transfer certificate, substantially in the form of Attachment D hereto, is completed to our satisfaction and received by us. All transfer charges shall be for the account of the Contractor. This Letter of

Credit may not be transferred to any person with whom U.S. persons are prohibited from doing business under U.S. Foreign Asset Control Regulations or other applicable U.S. laws and regulations. Transfer of the Letter of Credit may not change the place of expiration from our above office.

12. Complete Agreement. This Letter of Credit sets forth in full our undertaking, and such undertaking shall not in any way be modified, amended, amplified or limited by reference to any document, instrument or agreement referred to herein, except for the ISP-98 and Attachments A, B, C, and D hereto and the notices referred to herein and any such reference shall not be deemed to incorporate herein by reference any document, instrument or agreement except as set forth above.

SINCERELY,

WELL FARGO BANK, N.A.

_____

(Authorized Signature)

ATTACHMENT A

FORM OF DRAW CERTIFICATE

The undersigned hereby certifies to Wells Fargo Bank N.A. (the "Issuer"), with reference to Irrevocable Letter of Credit No. _____ (the "Letter of Credit") issued by Issuer in favor of the undersigned ("Beneficiary") (capitalized terms used herein and not defined herein shall have the respective meanings set forth in the Letter of Credit), as follows:

(1) The undersigned is the _____ of Beneficiary and is duly authorized by Beneficiary to execute and deliver this Certificate on behalf of Beneficiary.

(2) Beneficiary hereby makes demand against the Letter of Credit by Beneficiary's presentation of the draft accompanying this Certificate, for payment of _____ dollars (U.S.$_____), such amount, when aggregated together with any amount not drawn down, is not in excess of the Stated Amount (as in effect of the date hereof).

(3) Beneficiary is entitled to draw the amount set forth in paragraph 2 hereof because:

[Check applicable provision(s)]

[___] The conditions for a drawing pursuant to the Agreement have been met.

[___] The rating of the outstanding unsecured indebtedness of the bank or trust company that issued the Letter of Credit has fallen below a rating of A-, as determined by Standard and Poor's Corporation, or a rating of A-3, as determined by Moody's Investors Services, Inc., and Contractor has failed, within ten (10) days after receipt of written notice (copy attached) thereof by the Beneficiary to replace such Letter of Credit with another Letter of Credit issued by a financial institution acceptable to Beneficiary on the same terms as the Letter of Credit being replaced.

[___] The Contractor has failed to renew the Letter of Credit within sixty (60) Business Days prior to the expiration thereof.

(4) You are hereby directed to make payment of the requested drawing to: (insert wire instructions)

Beneficiary Name and Address

By: _____
Title: _____
Date: _____

ATTACHMENT B

DRAWING UNDER IRREVOCABLE LETTER OF CREDIT NO. ----------

Date:

ON: If the Draw Certificate is presented by 10:00 a.m., California time on any Business Day, payment will be made not later than 3:00 p.m., California time on the next day and if such Draw Certificate is so presented to us after 10:00 a.m., California time on any Business Day, payment will be made on the second Business Day.

PAY TO: Florida Power & Light Company

$_____U.S.

FOR VALUE RECEIVED AND CHARGE TO THE ACCOUNT OF LETTER OF CREDIT NO. _____.

Florida Power & Light Company

By: _____

Title: _____

Date: _____

ATTACHMENT C

CANCELLATION CERTIFICATE

Irrevocable Letter of Credit No. _____

The undersigned, being authorized by the undersigned ("Beneficiary"), on behalf of Beneficiary hereby certifies to Wells Fargo Bank N.A. ("Issuer"), with reference to Irrevocable Letter of Credit No. _____issued by Issuer to Beneficiary (the "Letter of Credit"; capitalized terms used herein and not defined herein shall have the respective meanings set forth or referenced in the Letter of Credit), that either (i) thirty (30) days have passed since the expiration of the Warranty Period (as defined in the Agreement) and Contractor has satisfied all obligations under the Agreement or (ii) the Agreement has been terminated and Contractor has performed all obligations and paid all amounts remaining due by Contractor following such termination. Pursuant to Section 5 thereof, the Letter of Credit shall expire upon Issuer's receipt of this certificate. Attached hereto is the Letter of Credit marked "Canceled".

Beneficiary Name.

By: _____

Title: _____

Date: _____

ATTACHMENT D
TRANSFER CERTIFICATE

Irrevocable Letter of Credit No. _____

The undersigned Beneficiary hereby certifies to Wells Fargo Bank N.A. ("Issuer"), with reference to Irrevocable Standby Letter of Credit No. _____ (the "Letter of Credit"; capitalized terms used herein and not defined herein shall have the respective meanings set forth in the Letter of Credit), that for value received Beneficiary hereby irrevocably transfers to _____ (the "Transferee") all rights of the undersigned under the Letter of Credit, including all rights of the undersigned to draw under the Letter of Credit and to execute and deliver drafts and draw certificates with respect hereto.

Beneficiary hereby certifies that the Transferee has agreed in writing for Contractor's benefit to be bound by the provisions set forth herein.

By this transfer, all rights of Beneficiary under the Letter of Credit are transferred to Transferee and Transferee shall have sole rights with respect to the Letter of Credit relating to any amendments thereof and any notices thereunder; and all references to "Beneficiary" or "Owner" in the Letter of Credit, any drawing certificate in the form of Attachment A or the other Attachments to the Letter of Credit shall be deemed to mean the Transferee. All amendments are to be advised directly to the Transferee without necessity of any consent of or notice to the undersigned. Simultaneous with delivery of this notice to Issuer, a copy of this notice is being transmitted to Transferee.

The Letter of Credit is returned herewith and Issuer is requested to endorse the transfer on the reverse thereof and forward it with your customary notice of transfer directly to the Transferee at the following address:

Florida Power & Light Company
(or its permitted transferee in interest)

By: _____

Title: _____

Date: _____

SIGNATURE GUARANTEED
The First Beneficiary's signature(s) with title(s) conforms with that on file with us and such is/are authorized for the execution of this instrument.

_____
(Name of Bank)

_____
(Bank Address)

_____
(City, State, Zip Code)

_____
(Telephone Number)

_____
(Authorized Name and Title)

_____
(Authorized Signature)

Appendix V – Contractor's Exclusions

HEARING EXHIBIT - 00000446

APPENDIX V

Contractor's Exclusions

None.

HEARING EXHIBIT - 00000447

APPENDIX W

Intentionally Deleted

HEARING EXHIBIT - 00000448

APPENDIX X

Intentionally Deleted

Appendix Y –Form of Quality Assurance Programs

HEARING EXHIBIT - 00000450

APPENDIX Y
FORM OF QUALITY ASSURANCE PROGRAMS

Contractor shall have in effect at all times a Quality System which as a minimum conforms to the American National Standard ANSI/ASQ ISO 9001, Model for Quality Assurance, or an approved alternative. The project specific Quality System will conform to but not be identical to the ISO 9001 Model. A site specific Quality System will be submitted for approval. This system shall ensure that all materials and services (including subcontracted materials and services) provided on this project comply with the specification and applicable Codes.

1.0 Quality Assurance Program:

1.1 Contractor shall have a QA Program in effect at all times to verify that all items and services, including subcontracted items and services, comply with the contract requirements.

1.2 This program will clearly establish the authority and responsibility of those responsible for the QA Program. Persons performing quality functions will have sufficient and well-defined responsibility and authority to enforce quality requirements; to identify, initiate, recommend, and provide solutions to quality problems; and to verify the effectiveness of the solutions.

1.3 Contractor shall submit a controlled copy of his QA or Quality Systems Manual for review and acceptance by Owner. In addition, Contractor will make available for review copies of any associated implementing procedures and/or instructions. A post award meeting will be held at Contractor's facility to discuss the Project's QA and quality requirements.

1.4 Contractor shall utilize a quality plan for all stages of the project including design, procurement, installation/erection, testing, start-up and turnover. The quality plan will identify critical activities, inspections and other quality verification points that will be performed to ensure the quality of work meets specified requirements.

1.5 Prior to the post award meeting, Contractor shall make available for review the quality plan for the project that includes implementing procedures, instructions, and check-sheets (which may include but not limited to):

1.5.1 Test & Inspections

1.5.2 Quality System Audits

1.5.3 Nondestructive Examination Control

1.5.4 Control of Special Process

1.5.5 Non-conformance Control and Corrective Actions

1.5.6 Material Control

1.5.7 Document Control and Record Retention

Contractor's preliminary site Construction Quality Plan includes "Inspection and Test plans" that comply with the National Codes (ASME, AWS, ACI). Owner will perform an overview of Contractor's Quality System. This overview does not include "Hold" or "Witness" points. Every effort will be made to implement a meaningful overview without impeding Contractor's efforts or job progress. Owner's overview is intended to assist Contractor implement an effective Quality System and associated quality controls focused on problem prevention and continuous improvement. Concerns arising from the overview activities will immediately be conveyed to Contractor for incorporation into Contractor's Quality System or Project's Quality Plan for corrective action, recurrence control, and trending. Owner's representatives will continually monitor and evaluate Contractor's timeliness and adequacy of corrective actions and recurrence controls.

1.6 If subsequent to its acceptance, the QA Program is found to be ineffective or inadequate in providing acceptable quality controls, Owner reserves the right to require the necessary revisions.

2.0 Contractor's Responsibilities for Suppliers

2.1 Material and equipment quality control: Contractor shall provide new equipment, materials and workmanship for their application.

2.2 Contractor is responsible for the work and materials specified in the contract and shall require its subcontractors/suppliers to comply with the appropriate technical and quality requirements of the specification and associated procurement documents.

2.3 Contractor will identify, in purchase documents to his suppliers, all applicable quality and QA requirements imposed by the specification on Contractor and will ensure compliance thereto. Contractor has the prime responsibility for vendor surveillance and evaluating and monitoring the implementation of

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HEARING EXHIBIT - 00000451

the Quality Assurance Programs of his suppliers. . The degree of overview should be based on results of the evaluation and ongoing quality performance.

2.4 Contractor will submit a copy of his Vendor Surveillance plans to Owner for review prior to implementation. Upon request, Contractor will submit to Owner copies of the reports of the vendor surveillance activities that he performs on his suppliers.

3.0 Witness Points

3.1 Owner will have the right to establish witness points for which Contractor will give ten (10) business days prior notification. In addition, Owner may establish witness points to ensure resolution of quality problems.

3.2 Witness points are defined as predetermined points during fabrication when equipment or activities may be inspected or witnessed for compliance with the Purchase Order, specification, and quality requirements.

3.3 Owner will have the right to access Contractor and Contractor's Suppliers facilities at any time to verify the progress and quality of the work.

4.0 Stop Work Action

4.1 Owner will orally notify and confirm in writing to Contractor of any situation where, in the judgment of Owner, Contractor or Contractor's suppliers are performing work contrary to the conditions and terms of the Contract or where continued operations could cause damage, preclude further inspection, or render remedial action ineffective for any product or service provided by Contractor or Contractor's suppliers.

4.2 If, after this notification, Contractor does not commence appropriate corrective action to the satisfaction of Owner, Owner will initiate stop work action on the specified product or service and so notify Contractor in writing.

4.3 Upon receipt of a Stop Work Directive (SWD) from Owner, Contractor and Contractor's suppliers will cease operations, including shipments, on any specified product or service to the extent stipulated by the SWD. Resumption of operations will not be undertaken until Contractor has obtained a written authorization from Owner. A written authorization to resume further operations will only be granted upon approval of Contractor's written commitment to correct those conditions itemized on the SWD. Correction of the actual deficiency will be required prior to release for shipment.

5.0 Deviations and Nonconformance's

5.1 Departure from any requirement of this Specification shall be considered a deviation or nonconformance. Examples include physical defects in equipment, test failures, equipment out-of-tolerance, or deviations from the specification, inspection or test procedures. No deviation or nonconformance from this Specification will be accepted until approved in writing by Owner.

5.2 Access to Contractor's facility and their suppliers' facilities shall be provided to the Owner (or agent) at its' option, to evaluate the effectiveness of the quality systems. Necessary changes, which may be required to conform to the above requirements, shall be made by Contractor.

6.0 Inspection, Shop Testing and Quality Verification

6.1 Contractor shall develop, implement and provide to the owner a Quality Control Plan for Equipment Suppliers that identifies the level and extent of shop inspection, testing and other quality verification activities. Contractor shall identify the number of man-days budgeted regarding each equipment supplier listed on the Quality Control Plan.

6.2 Testing programs shall be established by Contractor, but shall not be less thorough than the manufacturer's standard testing procedures or as outlined in the major equipment contracts. Contractor is responsible for insuring that the manufacturers meet specification requirements for quality, inspections and testing contained in all equipment contracts.

6.3 Contractor's inspection and testing programs can be established based on previous experience however Contractor shall demonstrate to Owner justification of inspection activities.

6.4 Contractor shall perform inspection, shop testing or other quality verification activities with appropriately qualified and experienced personnel.

6.5 Contractor shall develop and maintain a monthly schedule that identifies the quality verification activities and witness points to be performed on this project. Copies of this schedule shall be provided to the owner.

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6.5.1 The Owner reserves the right of shop inspection visits and may witness shop tests, provided that Contractors Schedule is not impacted. Any shop inspections by Owner does not relieve Contractor of its responsibility contained in the terms of the Contract. Contractor shall notify Owner of impending inspection visits or tests at least ten (10) business days in advance of inspections or tests. Shop inspections shall also be identified in Contractor's schedule.

6.6 Contractor shall furnish to Owner certified copies of test reports and shop tests whether Owner witnesses the shop test or not.

7.0 Equipment Expediting Services

Expediting services are included for all engineered equipment to track the engineering phase to ensure timely delivery of vendor design drawings and documents, as well as timely engineering design drawing review, and timely resolution of open issues. Expediting services are also included to track the manufacturing and testing phase to ensure timely shipment of equipment that passes all tests and meets vendor as well as Contractor quality assurance and quality control program requirements.

8.0 Construction Quality Control

First line, primary inspection and testing (hereafter referred to as Quality Control) is the responsibility of Contractor. Contractor's quality control procedures shall be clearly stated in the Project's Quality Control Manual, and shall specify field inspections and inspection criteria. Problems discovered during inspections and testing which could impair job cost, schedule, or facility function, will be immediately conveyed to Owner.

9.0 Construction Meetings

Contractor shall conduct meetings with subcontractor supervisory personnel prior to task performance, to insure understanding of the design specification requirements. At this time, inspection requirements and witness points shall be explained. Meetings shall be documented.

10.0 Construction Surveillance

The surveillance, which shall include hands-on inspections and documentation, verifies that the installations conform to the drawings, specifications, and applicable codes. Surveillance shall include in-process inspections, early in the process, as an effort to evoke problem prevention instead of problem resolution that comes with performing only final inspections. Contractor is obligated to engineer, construct and operate equipment in accordance with manufacturers' recommendations. Owner must be notified in writing prior to Contractor initiating actions that deviate from manufacturer's recommendations.

11.0 Test Monitoring

Testing shall be observed and documented by qualified Contractor personnel. Testing procedures and test reports should be reviewed as well as direct observation of the test process.

12.0 Inspection Plan

Contractor shall develop an Inspection Plan that identifies the Quality Control activities Contractor will perform. This plan shall outline the usage and extent of the above methods, or additional methods to be used by Contractor to monitor the quality of the installation. As a minimum, Contractor's Quality Control Program shall include monitor the systems and construction activities identified on Table 1.

13.0 As-Builts

Contractor shall develop and implement a document control program to ensure that the project submittals identified in section 11.3 of the EPC Contract Exhibit A, are properly controlled and as-builts are provided to the owner in accordance to the project document submittal schedule.

ECRC-08-3503 HEARING EXHIBIT - 00000453

Table 1
Minimum Construction QC Program Requirements

Systems/Components to be addressed (include but not limited to):

- Transformers
- Inverters
- Structural Steel
- Protective Relays
- Instruments & Controls
- Foundations
- Motors
- Cable trays, and conduit
- Switchgear, Busway, & Motor Control Centers
- PV panels

Construction Activities to be addressed (include but not limited to):

- Receiving Inspection & Storage
- Soil Compaction
- Coatings Application
- Survey Controls
- Cable Pulling and Terminations
- Host Utility Tie-ins
- Loop Checks of Instruments
- Close-out of Electronic Spaces
- Construction Tests, Turnover and Start Up
- Document Control
- Control of nonconformances
- Concrete Testing
- Structural Steel Jointing
- Setting of Protective Relays
- Close-out of Switchgear and Boxes
- Tagging/Clearance
- Calibration

End

ECRC-08-3504
HEARING EXHIBIT - 00000454

Appendix Z – Form of Safety Plan

HEARING EXHIBIT - 00000455

APPENDIX Z
FORM OF SAFETY PLAN

Safety Rules and Regulations for Contractors

1.0 Purpose

Safety is vital to the well being of all employees, the quality of the work being done, and the cost effectiveness of Owner projects. The purpose of this procedure is to ensure that contractors comply with OSHA standard 29 CFR Part 1926, identify and correct potential safety hazards prior to starting work, and monitor the effectiveness of their own safety programs.

2.0 Contractor's Responsibilities

2.1 Prior to the commencement of any site work by Contractor, Contractor will designate in writing to Owner a competent safety representative. This representative shall make frequent and regular safety inspections of the jobsite. These inspections shall be documented in writing to Owner's format or similar and submitted to Owner for his review within three (3) working days of performance. All at-risk behavior and/or unsafe conditions noted during the inspections shall be corrected immediately. At risk behavior and /or unsafe conditions noted during inspections shall be corrected immediately. A Job Safety Analysis (JSA) is required to be performed by Contractor for all essential jobs.

2.2 Contractor shall initiate an accident prevention program and shall instruct each employee on the jobsite in the recognition and avoidance of unsafe acts and/or conditions applicable to its work environment to control or eliminate injury. Contractor shall enforce the project and OSHA safety rules on its employees.

2.3 Contractor is responsible for providing and requiring the use of appropriate personal protective equipment (PPE) in all operations where there is and exposure to hazardous conditions or where the hazard assessment results would require PPE.

2.4 Contractor shall designate in writing to Owner the names of the competent persons as required by OSHA Standard 29 CFR Part 1926 for Contractor's work activities. Contractor shall ensure this individual understands his responsibilities and is capable of identifying existing and predictable hazards in the surroundings or working conditions which are unsanitary, hazardous, or dangerous to employees, and understands that he/she has the authorization to take prompt corrective measures to eliminate them.

2.5 Contractor shall initiate and implement a hurricane/severe storm preparedness procedure in accordance with section 23.0. (Need Clarification. OSHA Section 1926.23 does not refer to hurricane/severe storm preparedness.)

3.0 Pre-Construction Meeting

Contractor shall attend a pre-construction meeting with Owner to understand the project conditions, safety requirements, and site policies and rules before starting work at the jobsite. A jobsite tour may be made to confirm Contractor's awareness of potential safety hazards. It is Contractor's obligation to implement measures necessary to establish and maintain safe working conditions on the Project.

4.0 Instruction and Training

Instruction and training of employees in an OSHA requirement will be required on this project. Examples of such training to be provided by Contractor are:

4.1 Orientation – Newly employed or transferred personnel shall be instructed in the site safety rules/policies and the safety practices required by their work assignments. Contractor shall document this training and demonstrate to Owner that the employees know and understand the training.

4.2 Daily Work Assignments – All work assignments must include specific attention to safety. The Risk Assessment Tailboard (RAT) process or equivalent will be utilized each morning or when a new task is assigned. (See attached program)

4.3 Safety Meetings – Properly conducted and recorded weekly safety meetings are required. Results of these safety meetings are to be submitted to Owner within three (3) working days for review.

4.4 Specific Instructions – OSHA requires that employees who perform specific tasks or operate specific equipment be trained in its usage. Contractor shall ensure only those personnel qualified by training or experience shall be permitted to operate machinery. These qualifications shall be documented by Contractor, maintained and kept on file at the jobsite for review by Owner.

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5.0 Recordkeeping

It is the Contractor's responsibility to maintain all records required by OSHA, Workers Compensation Insurance or similar regulations. This includes the maintenance of an accident log, annual summary and posting of posters.

6.0 Hazardous materials

6.1 Contractor is responsible for notifying Owner of any hazardous chemicals or substances that are brought or caused to have been brought on the jobsite. The legal storage, use, and disposal of hazardous chemicals or substances are the responsibility of Contractor.

6.2 If hazardous chemicals are going to be used, then Contractor will implement a Hazard Communication program that will include training, MSDS, and labeling.

6.3 Use of chemicals may result in hazardous waste. In such cases, the Contractor shall institute a program to address hazardous waste storage and disposal in accordance with the code of federal regulations, state regulations, and other requirements delineated in the bid and contract documents.

6.4 When personal exposure to chemicals, particulates, aerosols or fumes is reasonably expected to exist and exceed allowable limits, then the Contractor shall put an Industrial Hygiene program in place.

7.0 Fire Prevention

7.1 Contractor shall be responsible for fire protection in its work, operational, and storage areas in accordance with all local, county, state, and federal requirements 24 hours per day, seven days per week, through the duration of this contract

7.2 Contractor shall comply with all fire and safety rules and regulations established on the project

8.0 Third Party Safety Inspections

In addition to visits and safety inspections by corporate representatives, Contractor is advised that the Project may be inspected from time to time by authorized third parties. These may include representatives of Owner, insurance companies, or OSHA. Upon proper identification, they are entitled to access and courteous consideration.

9.0 Project Safety Rules and Guidelines

All personnel on the project are required to comply with project specific rules and these guidelines. Contractor shall ensure that all of its employees have read these guidelines and understand its contents. The following jobsite rules apply:

9.1 Clothing Requirements

9.1.1 Shirts with at least a 4-inch sleeve shall be worn at all times. Tank tops are not permitted.

9.1.2 Long pants are required.

9.1.3 Sandals, tennis shoes, or any other street type shoe will not be permitted.

9.1.4 Loose fitting clothes or jewelry shall not be worn around moving machinery, grinding operations, etc.

9.2 Personal Protective Equipment

9.2.1 ANSI approved hard hats shall be worn at all times in the construction area unless a hazard assessment performed by the Contractor shows that wearing the hard hat would make the specific job more unsafe. All areas of this jobsite are hard hat areas. This includes cabs on heavy equipment such as cranes and backhoes.

9.2.2 Safety glasses with side shields are required in the construction areas at all times.

9.2.3 Approved eye and face protection is required as follows: goggles, welding hoods and shields, and face shields will be required to be properly worn at all times when in the area of operations, such as when welding, burning, grinding, chipping, chemical handling, corrosive liquids or molten materials, drilling, sawing, driving nails, power actuated tools, concrete pouring, tampers and gas fueled hand operated equipment (i.e. chainsaws). This section will also apply to those employees of Contractor who are assisting any worker as an apprentice or helper. Prescription glasses must be ANSI approved or safety glasses must be worn over the prescription glasses.

FCRC-08-3507 HEARING EXHIBIT - 00000457

9.2.4 OSHA approved hearing and respiratory equipment shall be worn when required. Contractor shall meet the selection, fitting and maintenance requirements of OSHA.

9.2.5 All employees shall wear approved safety harnesses when working six feet or more above the ground or when working in a precarious position. The lanyard shall be securely attached to the employee 100% of the time and shall be rigged such that the employee can neither free fall more that 6 feet (1.8m), nor contact any lower level. Safety harnesses shall also be worn and attached to the tie-off rail when working out of extensible and articulating boom platforms and to vertical drop lines when working from suspended scaffolding. Specific project requirements may exist and contractor will adhere to the more stringent requirements of fall arrest equipment use.

9.2.6 Seat belts shall be worn by all employees operating any motor vehicle and any equipment with rollover protection structures during performance of the work.

9.2.7 Safety nets shall be provided when work places are more than 25 feet above the ground where the use of other fall protection devices is impractical.

9.2.8 Approved work boots or shoes shall be worn in all construction areas unless a hazard assessment performed by the Contractor shows that ANSI approved shoes are required. All contractors shall ensure that their work boots or shoes provide adequate protection from foot injuries due to falling or rolling objects as identified in the hazard assessment. Deck and athletic style shoes are not considered an approved work shoe and are not to be worn on the project.

9.2.9 Chemical resistant protective footwear shall be worn when there is a possibility of hazardous chemicals coming in contact with the foot. Chemical resistant footwear shall be resistant to the type of chemical to which it is exposed.

9.2.10 Work gloves are required to be worn for all manual material handling jobs.

10.0 Signs, Signals, Barricades and Lights

10.1 Signs, Signals and barricades shall be visible at all times where a hazard exists.

10.2 All streets, roads, highways, and other public thoroughfares, which are closed to traffic, shall be protected by effective barricades on which shall be placed acceptable and highly visible warning signs. Barricades shall be located at the nearest intersecting public highway or street on each side of the blocked section.

10.3 All open trenches and other excavations shall be provided with suitable barriers, signs, and lights to the extent that adequate protection is provided. Obstructions, such as material piles and equipment, shall be provided with similar warning signs and lights.

10.4 All barricades, signs, lights and other protective devices shall be installed and maintained in conformity with applicable statutory requirements.

10.5 When any work is performed at night or where daylight is shut off or obscured, Contractor shall, at its expense, provide artificial light sufficient to permit work to be carried on efficiently, satisfactorily and safely, and to permit thorough inspection. During such times, the access to the place of work shall also be clearly illuminated. All wiring for electric light and power shall be installed and maintained in a first-class manner, securely fastened in place at all points, and shall be kept as far as possible from telephone wires, signal wires, and wires used for firing blasts.

10.6 Signs, signals and barricades shall be removed when the hazard no longer exists.

10.7 Contractor's employees working in an area of potential traffic had shall wear approved reflective type vests.

11.0 Rigging Equipment

11.1 All rigging equipment shall be free from defects, in good operating condition and maintained in a safe condition. Rigging equipment shall be inspected before use on each shift and as necessary to ensure that it is safe.

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11.2 A designated, competent employee of Contractor shall thoroughly inspect rigging equipment monthly to ensure that it is safe. Records shall be kept on jobsite of each of these inspections by Contractor and shall be made available to Owner upon request.

11.3 Contractor shall immediately remove damaged rigging equipment from service.

12.0 Hand and Power Tools

12.1 All hand and power tools, whether furnished by Contractor, or by Contractor's employee, shall be maintained in a safe condition.

12.2 Contractors shall not issue nor permit the use of unsafe hand or power tools.

12.3 Electrical power tools shall be grounded or double insulated with proper assured equipment grounding inspections or Ground Fault Interrupter circuit protection provided.

12.4 Pneumatic power tools shall be secured to the hose or whip by some positive means.

12.5 Only properly trained Contractor's employees shall operate power actuated tools. Contractor shall maintain certification records, employee certification cards, or equivalent certification documentation or each of its employees using power actuated tools during performance of the work.

12.6 All portable grinders shall conform to OSHA and ANSI requirements.

12.7 Cords, leads and hoses shall be kept at least seven feet off the ground or placed off to the side to prevent creating a tripping or traffic hazard.

13.0 Compressed Gas Cylinders

13.1 Compressed gas cylinders shall be secured in an upright position at all times. Location of cylinder storage areas must be approved by Owner.

13.2 When transporting, moving and storing cylinders, valve protection caps shall be in place and secured.

13.3 Cylinders shall not be hoisted by magnets or choker slings. Valve protection caps shall not be used for hoisting cylinders.

13.4 Cylinders shall be kept away from sparks, hot slag and flames, or be adequately protected.

13.5 Cylinders shall not be placed where they can become part of an electrical circuit.

13.6 Cylinders shall be labeled as to the nature of their contents.

13.7 Oxygen cylinders in storage shall be separated from fuel gas cylinders or combustible material a minimum of 20 feet, or by a non-combustible barrier at least five feet high having a fire resistant rating of at least one-half hour. Empty cylinders shall be separated as above from full cylinders and stored with like cylinders.

13.8 "No Smoking" signs shall be posted at storage areas and signs shall clearly indicate contents of cylinders.

13.9 Anti-flash back valves shall be provided on all oxygen and acetylene lines.

14.0 Jobsite Transportation Rules

14.1 All drivers of motor vehicles shall be licensed, trained, and instructed to exercise good cautious operating judgement as well as observe posted speed limits. Maximum speed limit is 25 miles per hour unless posted otherwise. However, slower speeds are necessary in congested areas.

14.2 Seat belts shall be worn at all times when travelling in vehicles and equipment.

14.3 All Contractor's means of ingress, egress and parking will be adequately marked as such, since their employees are to travel these routes only.

14.4 Use your horn for safety at blind corners, when passing, etc.

14.5 Established hand signals or turns signals are to be used.

14.6 Reckless driving or other non-observance of these instructions will be cause for withdrawal of drive-in privileges and may result in denial of access to the project.

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HEARING EXHIBIT - 00000459

15.0 Cranes and Derricks

15.1 Contractor shall certify all cranes and derricks as being in safe operating condition before using the crane or derrick on jobsite. This certification shall be maintained by Contractor and made available to Owner upon request.

15.2 Contractor shall comply with the manufacturer's specifications and limitations applicable to the operation of all cranes and derricks. Contractor shall designate a competent person who shall inspect all machinery and equipment before each use, to make sure it is in safety operating condition. Any deficiencies shall be repaired, or defective parts replaced, before continued use.

15.3 The swing radius of cranes shall be barricaded where practical and/or in areas where work is being performed.

15.4 Hand signals prescribed by ANSI shall be posted at an operator's station; employees assigned to work around the crane will be trained in the use of hand signals.

15.5 Equipment shall not be operated where any of the equipment or load will come within 10 feet (3.1 M) of electrical distribution or transmission lines less than 50 kV. Minimum clearance between lines and any part of the crane or load must be 10 feet plus 0.4 inches for each 1 kV over 50 kV or twice the length of the line insulator but never less than 10 feet.

15.6 Contractor's employees shall not ride headache ball, hook, or load being handled by the crane.

15.7 While in use, equipment shall not be lubricated or have maintenance performed.

15.8 Rated load capabilities, recommended operating speeds, special hazard warning, specific hand signal diagrams and special instructions shall be visible to the operator while he is at the control station.

15.9 Contractor's employees shall not be allowed to work under the load of cranes. Tag lines shall be used on all loads. Special caution should be used in concrete bucket operations.

15.10 Cranes and derricks shall be inspected prior to use and at monthly intervals. Contractor shall maintain records on jobsite of these inspections. Contractor shall make copies available to Owner upon request.

16.0 Equipment and Motor Vehicles

16.1 All equipment must be inspected daily before use by Contractor's operator. Contractor must also make formal inspections at 30-day intervals with proper documentation maintained at the jobsite by Contractor and copies shall be made available to Owner upon request.

16.2 Defective equipment shall be repaired or removed from service immediately.

16.3 All rubber-tired, self-propelled scrapers, rubber-tired, front-end loaders, rubber-tired dozers, wheel-type agricultural and industrial tractors, crawler tractors, crawler-type loaders and motor graders shall be equipped with rollover protective structures and seat harnesses.

16.4 All Contractors' operators of construction equipment should be properly licensed and certified by a competent person. Copies of the certifications shall be maintained on jobsite by Contractor and made available to Owner upon request.

16.5 All equipment with an obstructed view to the rear must have a reverse signal alarm audible above the noise level or a flagman.

16.6 All cracked or broken glass shall be replaced before bringing vehicles on the jobsite. If glass is broken or damaged on jobsite and if damage is severe enough to cause a potential safety problem, the machine shall be stopped until such damage has been repaired.

16.7 Vehicles used to transport employees shall have seats firmly secured and adequate for the number of employees to be carried and all passengers should be properly seated. Standing on the back of moving vehicles is prohibited.

16.8 Location for storage of all fuels, lubricants, starting fluids, etc., shall be reviewed by Owner before use by Contractor.

17.0 Ladders

17.1 The use of ladders with broken or missing rungs or steps, broken or split rails or other defective construction is prohibited.

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17.2 Ladders shall extend no less than thirty-six inches (36") above landing and be secured to prevent displacement.

17.3 Portable ladders must be equipped with safety shoes.

17.4 Wooden ladders shall not be painted.

17.5 Metal or conductive ladders shall not be used on the jobsite.

18.0 Floor and Wall Openings and Stairways

18.1 Floor and wall openings shall be guarded by a standard guardrail, midrail, and toeboard, or a cover installed and secured to prevent movement.

18.2 Guardrails must be of sufficient strength to support two hundred (200) pounds of pressure when applied at midspan of the guardrail parallel with the floor and perpendicular to the guardrail with a minimum deflection of three (3) inches.

18.3 Covers must be adequately secured to prevent displacement and have "Danger" signs attached identifying the hazard.

18.4 Every flight of stairs having four or more risers shall be equipped with standard stair railings. Stairs are not to be used until risers and railings are securely installed. Treads will be poured as soon as possible were poured treads apply.

18.5 Debris and other loose materials shall not be allowed on stairways or at access point to stairway. Debris shall not be allowed to accumulate on stairwells.

19.0 Excavations and Trenching

19.1 Prior to opening any excavation or trench, Contractor must notify Owner. In addition, Contractor shall contact any other necessary personnel to determine whether underground installations, i.e., sewer, telephone, fuel, electric lines, etc., may be encountered and where they are located. An excavation permit may be required specific by project.

19.2 Excavations and trenches shall be inspected by a competent person daily and after every rainfall to determine if they are safe.

19.3 After the soil is classified, all banks 4 feet high or more shall be sloped to the angle of repose (the greatest angle above the horizontal place at which a material will lie without sliding), shored, or have trench shields installed.

19.4 Ladders or steps shall be provided in all trenches 4 feet or more in depth. Ladders or steps shall be located to require no more than 25 feet of lateral travel before having access or egress.

19.5 Material excavated shall be stored at least 2 feet from the edge of the excavation, or the trench shall be shored to prevent material from falling into the excavation.

19.6 All trenches and excavations shall be properly barricaded to prevent persons from waling into them.

19.7 All walkways or ramps crossing over excavations shall be securely fastened and equipped with standard guardrails.

20.0 Housekeeping

20.1 During the course of construction, all debris and scrap material shall be kept away from the work area.

20.2 Containers shall be provided by Contractor for the collection and separation of waste, trash, oily and used rags and other refuse. Metal (dumpster type) containers must be used and emptied promptly.

20.3 Garbage and other waste shall be disposed of at frequent and regular intervals in a manner approved by Owner.

20.4 Contractor shall notify Owner of any hazardous waste it will generate during performance of the work. Contractor has the direct responsibility of maintaining proper storage of these wastes while onsite and will verify to Owner in writing that the wastes have been disposed of in a legal manner.

20.5 Contractor shall not pour, bury, burn, nor in any way dispose of any chemical on the work jobsite without the written permission of Owner.

20.6 Contractor shall dispose of all combustible debris to a solid waste disposal site.

ECRC-08-3511 HEARING EXHIBIT - 00000461

20.7 NO OPEN BURNING OF DEBRIS OR RUBBISH WILL BE PERMITTED ON THE PROJECT.

20.8 Materials and supplies shall be stored in locations that will not block access ways, and shall be arranged to permit easy cleaning of the area.

20.9 All hoses, cables, extension cords, and similar materials shall be located, arranged, and grouped so they will not block any access way and will permit easy cleaning and maintenance.

21.0 Medical Services - Contractor's Responsibilities:

21.1 Provisions shall be made prior to commencement of the project for prompt medical attention in case of serious injury.

21.2 Contractor shall ensure that first aid supplies be easily accessible when required. Contents shall be inspected and refilled weekly.

21.3 Contractor shall provide proper equipment for prompt transportation of injured person to a physician or hospital or a communication system to contact necessary ambulance service.

21.4 Contractor shall post telephone numbers and addresses of the physicians, hospital and ambulances.

21.5 Contractor shall complete and retain on file "Employer's First Report of Injury" and OSHA Form 300 and provide Owner a copy upon request.

21.6 Contractor shall ensure that each of its lower-tier subcontractors meet these medical requirements.

22.0 First Aid and Medical Procedures

22.1 Each occupational illness or injury shall be reported immediately by Contractor to Owner's project manager. For emergency cases, ambulance services will be contacted immediately by the quickest means available.

22.2 A daily record shall be kept on all employees requiring first aid treatment.

22.3 If medical treatment is required, Contractor must provide transportation of the injured to a hospital or physician. A representative of the Contractor shall accompany the injured employee and remain at the facility until the employee is ready to return. All reports from the physician concerning treatment, diagnosis, return to work status and restrictions shall be brought back to the project and a copy forwarded to Owner's construction manager, subject to employee's permission through the medical treatment authorization form provided in contractors safety plan..

22.4 Contractor must conduct accident investigations for all serious accidents and OSHA recordable injuries. The accident report shall include root cause determination, corrective actions taken, and measures to prevent the incident from reoccurring.

23.0 *Hurricane/Severe Storm* Emergency Response Procedure

23.1 Contractor will implement an organized, orderly system to prepare the Project site for inclement weather associated with hurricanes or severe storms.

23.2 Contractor is responsible for training each of their employees on the Construction Project Hurricane / Severe Storm Emergency Response Procedure

23.3 Contractor shall establish a Storm Damage Assessment Team.

23.4 Contractor shall monitor hurricane / severe storm activity by all available resources (i.e. Internet, radio broadcast, weather bulletins, etc).

24.0 Hurricane / Severe Storm Preparedness Plan:

Contractor program shall address inspection of work areas; storage areas, shops and trailers to ensure all equipment and material are properly secured. As a minimum, the following activities shall be addressed:

24.1 Hurricane / Severe Storm Watch (36 to 48 Hours Notice):

24.1.1 Band and secure all lumber.

24.1.2 Band and secure all plastic pipe, conduit, and other similar objects.

24.1.3 Band and secure all siding, decking, sheet metal, and other similar objects.

24.1.4 Dismantle and/or secure all scaffolds and temporary platforms.

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HEARING EXHIBIT - 00000462

24.1.5 Inspect and secure all temporarily installed piping, ductwork, and equipment. The may include adding lashing or lowering the equipment or material to the ground.

24.1.6 Finish bolting up all unfinished erected structural steel. Add additional steel, if necessary, to ensure the stability of the structure.

24.1.7 Lash down all unsecured tanks, silos, ductwork, and hoppers.

24.1.8 Tie down all storage vans, SEA containers, and temporary structures. This includes stairways, printshacks, and other similar structures.

24.1.9 Tie down all gang boxes or other similar items located in elevated positions up in the structures.

24.1.10 Dismantle and/or secure all large signs and similar structures.

24.1.11 Remove all radiation sources from the project.

24.1.12 If possible, remove all fuel trucks and tanks from the project. Trucks and tanks left onsite shall be secured and diked to contain a spill.

24.1.13 If possible, all hazardous material shall be removed from the project. Material left onsite shall be secured and diked to contain a spill.

24.1.14 All elevated work areas for example; Turbine decks shall be cleared of all loose material.

24.2 Hurricane / Severe Storm Warning (1 to 24 Hours Notice):

24.2.1 Contractors should make sure that all materials and equipment are secured by this time.

24.2.2 Shut down the Project Construction Power System.

24.2.3 Shut off the construction water system.

24.2.4 All crane booms shall be lowered to the ground and secured.

24.2.5 All small vehicles such as golf carts, welding machines and compressors shall be secured.

24.2.6 All office trailers and buildings shall be locked.

24.2.7 Project shall be evacuated.

24.3 Following a Hurricane / Severe Storm:

24.3.1 Once the hurricane / severe storm has passed, the Storm Damage Assessment Team shall return to the site to determine if the site is safe for employee re-entry.

24.3.2 Each contractor shall appoint a management person as a contact. The Storm Damage Assessment Team shall communicate to the appointed persons the condition of the site.

24.3.3 If the site is unsafe for employee entry, the Storm Damage Assessment Team shall determine what resources are needed to make the site safe for re-occupancy.

24.3.4 The Storm Damage Assessment Team shall request from the appropriate contractor site management appointee the necessary resources to prepare the site for re-occupancy.

24.3.5 Only when the site has been determined safe for re-occupancy by the Storm Damage Assessment Team, shall site personnel be allowed back to the site to resume normal construction activities.

24.4 Hurricane/Severe Storm Response Construction Site Team

Contractor shall maintain a list of team members and phone numbers of those employees on the site teams.

ECRC-08-3513
HEARING EXHIBIT - 00000463

EXHIBIT Z - ATTACHMENT 1

My Safety Principles

- Plan every job
- Anticipate unplanned events
- Use the right tool for the job
- Identify the hazard
- Assess the risk
- Put controls in place to minimize the possibility of injury
- Protect each other
- Use a "Buddy" system
- Do not take short cuts
- Believe in Zero Injuries
- Wear protective equipment
- Keep all work areas clean
- Inspect all tools prior to each use

Post Job Safety Review

1. Was anyone injured or did an unplanned event occur today?
   Yes_____ No_____
   If yes, explain:
   _____
   _____
   _____
2. What problems did you have with today's work assignment?
   _____
   _____
   _____
3. What can we do tomorrow to improve performance?
   _____
   _____
   _____
4. Other concerns/comments
   _____
   _____
   _____

Reviewed by: _____
Supervisor/foreman

Crew

Name	Badge #

FPL Energy

Power Generation Projects

Risk Assessment/Tailboard Sheet

Safety PD Team

SOARING TO NEW HEIGHTS

FPL

Tailboard

Supervisor_____
Date_____
Job description _____
_____
Location _____
Is a specific procedure required for this job? Yes ____ No ____
If yes, review procedure.
Is specific training required for this job?
Yes ____ No ____
If yes, ensure training is done.
_____

Personal Protective Equipment

	Yes	No	Type *
Eye/face	____	____	_____
Fall	____	____	_____
Hand	____	____	_____
Hearing	____	____	_____
Respirator	____	____	_____

* Type PPE: faceshield, goggles, ear plugs/muffs, welding(leathers), life vest, safety harness, special gloves (chemical resistant), respirator.

Other_____
_____

Material Safety Data Sheet

____ I have a copy of and have read the Material Safety Data Sheet for the hazardous chemical that I am using.

Risk Assessment

Potential Hazards	*Controls or Corrective Measures*

Housekeeping
____Keep work area and access clear
____Remove nails in boards
____Clean work area daily

Fall Protection
____100% tie off above 6 feet
____Lifeline installed
____Double Lanyards/harness

Lifting
____Lift with legs and with back straight
____Get help with heavy loads
____Use material handling equipment
____Get help for weight over 40 lbs

Ladders
____Tie off ladders using 4 to 1 rule
____Face ladder when climbing
____Use both hands when climbing
____Extend 36" above landing
____Use handline to raise or lower tools
____One worker on a ladder

Pinch Point/Line of Fire
____Wear gloves
____Be aware of swing radius on machinery
____Don't place hands on end of pipe
____Use a tag line to control material

Lockout/Tagout
____The equipment has been properly tagged or locked out, drained, vented, and energy released

Rigging
____Inspect rigging before each use
____Do not work under and overhead load
____Check load charts for safe work limits
____Check tag on nylon sling for load limits

Power Hand Tools
____Use guards and handles
____Wear eye protection
____Unplug tools when not in use
____Proper tool is in use for the job
____Inspect tools daily

Welding/Burning
____Wear gloves/protective clothing
____Use cutting/burning goggles
____Use/inspect fire extinguisher
____100% spark containment
____Ground welding machine
____Post "Hot Work Permit" if required
____Move/cover combustibles in area

Excavations
____Ladders every 25 feet
____Know soil classification
____Slope, shore, or shield over 5 feet
____Barricade around open trench
____Keep spoils 2 ft back from edge

Scaffolds
____Check for ladder access
____Insure standard guardrails are installed

EXHIBIT Z - ATTACHMENT 2
Risk Assessment Tailboard (RAT) Process

Definition

The Risk Assessment Tailboard sheet is a daily task process that empowers the employees to assess the hazards for the job and implement controls necessary to attain Zero accidents. It also provides a check sheet for personal protective equipment use, training, procedural compliance, and provisions for a post safety job review. The risk assessment process is to be used at least daily.

Purpose

FPL recognizes the importance of holding tailboards before each job, assessing the hazards of that particular job, and instituting the necessary controls to minimize the potential for injury. Daily planning involves safety instruction by the supervisor and crew input into the hazard assessment and control process before the job begins.

Process

- All known hazards must be identified, removed, abated, and/or acknowledged by the crew.
- The foreman/supervisor shall analyze each task for hazards and indicate what safety measures need to be taken.
- The supervisor shall ensure that each employee understands the work to be performed, hazards present, and corrective measures needed to prevent injury.
- If the work changes or unexpected problems arise during the work activities, then another safety assessment is to be done.
- The supervisor shall assure that the necessary safety equipment, procedures, and/or training is provided to the employees before work begins.

Documentation and Feedback

With the exception of the post job safety review, the RAT sheet is to be completed entirely before the work begins. It is the supervisor's responsibility to audit the work throughout the day to ensure adherence to the risk assessment process.

FPL construction management has the responsibility to audit the work activities throughout the day to ensure precautions are being taken and controls are in place.

At the end of the day, the supervisor completes the post job safety review section of the RAT sheet. It is then turned in to the FPL Construction Manager weekly for review and action as needed.

Report all accidents and near misses to supervision. It is essential to analyze these incidents to determine why problems occurred and to institute changes for future work.

END

FCRC-08-3515
HEARING EXHIBIT - 00000465

Appendix Z-1 – Safe and Secure Workplace Policy

HEARING EXHIBIT - 00000466

APPENDIX Z-1
SAFE AND SECURE WORKPLACE POLICY

Rev. 9/9/98

SAFE AND SECURE WORKPLACE POLICY FOR SUPPLIERS

Objective: To provide a safe and secure workplace for FPL employees, supplier employees, customers and the public.

Scope: This Policy applies to any individual or organization, its employees and its sub-contractors, (hereinafter collectively referred to as "Supplier"), responsible for performing the work identified by the purchase contract, for or on behalf of Florida Power & Light Company (hereinafter referred to as "FPL") and its subsidiaries on FPL premises, FPL customers' premises, FPL rights-of-way or FPL facilities, including facilities under construction and excluding only nuclear power stations, (hereinafter collectively referred to as "FPL Premises"), for periods equal to or greater than 30 employee days cumulative per calendar year. For example, if a Supplier has 30 employees who each work one full 8 hour day on FPL Premises in any one calendar year, this Policy applies to the Supplier. If a Supplier has one employee who works 30 or more full 8 hour days in any one calendar year on FPL Premises, this Policy applies to the Supplier.

The policy covers three specific areas:

- Pre-assigned Screening
- Controlled Substance and Alcohol Abuse
- Workplace Violence Policies

Violation: If Suppliers' employees are found to be in pre-access violation of this Policy, Supplier's employees shall be denied access to FPL Premises. Supplier employees found to be in post-access violation of any part of this Policy shall be removed immediately by the Supplier from FPL's Premises.

Compliance: If Supplier fails to comply with this Policy, Supplier may be considered in breach of contract. FPL or its designee shall have upon request immediate access to Suppliers' records to assure compliance with the requirements of this Policy.

Policy Details: The Supplier must address three specific issues regarding Safe and Secure Workplace.

II. Controlled Substances and Alcohol Abuse:

All Supplier employees should be fit-for-duty and report to work able to perform their duties safely. Use or possession of controlled substances and/or alcoholic beverages, as defined in

Chapter 561 of the Florida Statutes, by Supplier employees is an unsafe work practice which creates an increased risk to Supplier employee safety and the safety of others. The use or possession of any illegal drug or controlled substance without a valid prescription and/or the misuse of any prescription or over-the-counter medication by any Supplier employee shall constitute a violation of this Policy.

Any Supplier employee who is consuming or is under the influence of any alcoholic beverage while on FPL Premises shall be in violation of this Policy.

All Suppliers must have in place a controlled substance and alcohol Policy All employees who are subject to the requirements of the Omnibus Transportation Employee Testing Act of 1991, including Supplier employees required to hold a Commercial Driver's License, will be subject to random testing for controlled substances and alcohol according to the federally mandated random testing rate.

Supplier employees will be denied access to or immediately removed from FPL Premises for: (1) Possession or use of a controlled substance without a valid prescription; (2) distribution or sale of controlled substances at any time on or off the job; (3) positive test result for controlled substances without a valid prescription or alcohol; (4) being under the influence of a controlled substance or alcohol; or (5) refusal to test for controlled substances or alcohol.

ECRC-08-3517 HEARING EXHIBIT - 00000467

Supplier employees taking prescription medication are required to consult with their physicians to determine whether the medication may have an adverse effect on performance. Supplier employees taking over-the-counter medication are responsible for being aware of any adverse effects it may have on their performance as defined on the manufacturer's label. If prescribed or over-the-counter medication may have an adverse effect on performance, the Supplier employee is required to notify the Supplier prior to reporting to FPL's Premises. Failure to inform the Supplier's representative of taking prescription or over-the-counter medication which may have an adverse effect on performance may result in that employee's denial of access to FPL Premises. In all events the Supplier is responsible for determining the employee's fitness for duty.

Supplier employees taking prescription medications must be prepared to provide satisfactory, verifiable proof that the medication has been prescribed to the Supplier employee, and that it is necessary for the individual's current medical condition. Possession of the prescription bottle will provide the required proof.

Any Supplier employee called to perform unscheduled work at FPL Premises must state whether he/she has consumed alcohol within five (5) hours of the time he/she reports to work or is otherwise "unfit" for duty. Supplier employees that have consumed alcohol within the five (5) hour abstinence period shall not be permitted to work on FPL Premises except under conditions when:

1. The Supplier employee being called believes that he/she is fit for duty; and, based on information provided by the individual, the Supplier also believes he/she is fit for duty; or
2. The Supplier employee's fitness for duty is verified by a breath analysis for alcohol prior to entering the FPL worksite and the individual believes he/she is fit for duty.

In addition to the requirements set forth herein, all Suppliers shall comply with all applicable state and/or federal laws regarding drug and alcohol testing of their employees that are assigned to FPL Premises. All testing performed pursuant to this policy shall be at the blood alcohol rates specified in the Omnibus Transportation Employee Testing Act of 1991. **All Supplier employees will be subject to "post accident" and/or "reasonable suspicion" controlled substances and alcohol testing while on FPL Premises. "Reasonable suspicion" shall be determined in the sole discretion of FPL. No Supplier employee required to take a post-accident alcohol test under the Policy shall use alcohol for eight hours following the accident, or until he/she undergoes a post-accident alcohol test, whichever occurs first. This testing will be required when there is reasonable suspicion that an individual is in violation of the substance abuse and alcohol Policy. Supplier shall immediately notify FPL of any accidents involving or caused by its employees or subcontractors on FPL Premises.**

III. Workplace Violence:

FPL is committed to providing a safe and secure workplace. Supplier employees are expected to work in concert with FPL employees to ensure that the workplace remains safe and secure for all.

Behavior that could be perceived by a reasonable person as threatening or indicating the possibility of violence is prohibited. This may include, but is not limited to verbal threats, gestures, abusive language or physical altercation (fighting, shoving, etc.).

Displaying or carrying in any manner a weapon, firearm or destructive device (as those terms are defined in Chapter 790 of the Florida Statutes) on the Supplier employee's person or in his/her belongings, on any FPL Premises, in his/her personal vehicle while engaged in FPL work or activities, or in an FPL vehicle at any time is prohibited.

Supplier employees that violate these policies will be removed immediately by the Supplier from FPL Premises, and denied access to any FPL Premises. Supplier shall immediately notify FPL Corporate Security of violations of this Section III.

IV. Reporting Illegal Conduct or Workplace Violence:

FPL employees and Supplier employees benefit from an atmosphere of good ethical and legal conduct. Suppliers and their employees with information concerning abuse of company assets, fraud, theft, possession or use of illegal drugs, threats of violence or any other behavior at FPL that might be considered illegal, shall

ECRC-08-3518 HEARING EXHIBIT - 00000468

report that information immediately. Such information can be reported to the corporate security hotline anytime day or night at 888-694-6444.

V. **Acknowledgment:**

Suppliers must make their employees aware of this Policy and have Supplier employees acknowledge so in writing prior to beginning work at FPL Premises.

ECRC-08-3519
HEARING EXHIBIT - 00000469

Appendix HH – Acceptance Testing

HEARING EXHIBIT - 00000470

5

FPL's Response to Staff's Fourth Request for Production of Documents (No. 14)

HEARING EXHIBIT - 00000471

S.F. HOLDEN, INC.

REAL ESTATE APPRAISERS AND CONSULTANTS
Licensed Real Estate Broker

Square Lake Centre, Suite 10 8259 North Military Trail Palm Beach Gardens, Florida 33410-6352
(561) 626-2004 Fax (561) 622-7631

January 31, 2008

Mr. Tim Corson
FP&L Corporate Real Estate
700 Universe Boulevard
June Beach, FL 33406

Re: A 46.0-acre tract of land currently an old citrus grove on the northwest side of Courtenay Parkway (SR 3), adjoining the Kennedy Space Center, adjacent east to an Air Liquide industrial plant, on Merritt Island in unincorporated Brevard County, Florida.

Dear Mr. Corson:

We have investigated and analyzed the referenced property for the purpose of estimating its market value in fee simple as of January 17, 2008, the last date of formal inspection. The property is described in the attached report.

The property is part of NASA's 140,000-acre Kennedy Space Center, the principal home and launch facilities of the U.S. Space Shuttle program. The appraised property is an old citrus grove operated under license from the U.S. Fish & Wildlife Service, which manages all of the undeveloped land within the Kennedy Space Center. The location of the appraised property is just inside the south boundary of the Merritt Island Natural Wildlife Refuge.

The scope of our analysis included inspection of the property, collecting and analyzing relative data and information about the property and of comparable properties, and applying the applicable approaches to value. Since the property is undeveloped land, only the sales comparison approach was utilized. We also had conversations with Mr. Jim Ball of NASA in order to understand the basis of land use and zoning issues, and the limitations on development imposed by NASA on land use and third-party development within the space center.

Based upon our investigation and subject to the assumptions and limiting conditions set forth in the attached report, it is our opinion that the market value of the fee simple interest of the 46.0 acre parcel of land appraised, as of January 17, 2008, was **$75,000 per gross acre**, resulting in a value of:

THREE MILLION FOUR HUNDRED FIFTY THOUSAND DOLLARS
($3,450,000)

This opinion of value is qualified by certain definitions, assumptions and limiting conditions set forth on Pages 5 through 11 of the attached report. We particularly call your attention to the following Extraordinary Assumptions:

1. No formal survey of the property is available and the property's size of 46.0 gross acres, is based on calculations made by personnel of the Kennedy Space Center. We have assumed this size accurately reflects the land being considered by our client and have relied on this size in our valuation.

2. NASA is proposing a long-term lease of the appraised property to FP&L, but limitations on the use of the land (type of permitted uses) have not been reduced to writing and available for consideration in our appraisal. NASA, the Kennedy Space Center and the Fish & Wildlife Service will dictate the uses deemed appropriate for the land, but no local zoning and land use regulations apply within the federal government ownership. We have assumed that the property would have a mixture of comparative permitted uses as outlined in Brevard County's three primary industrial zoning classifications (PBP, PIP and I-U). If the uses under NASA are restricted or materially less than those permitted in the latter three county zoning classifications, our estimate of value would require reconsideration. (For expanded discussion on this assumption, see Land Use Plan/Zoning, and Highest and Best Use sections in the report.)

This summary appraisal was prepared under the Uniform Standards of Professional Appraisal Practice (USPAP). The report is intended only for the client's use, or its designated agents, and may not be relied upon for any other use or distributed to any unintended user without permission.

ECRC-08-080
HEARING EXHIBIT - 00000473

Thank you for the opportunity to be of service to you in this matter.

Respectfully submitted,
S. F. HOLDEN, INC.

Philip M. Holden, MAI
State-Certified General Real Estate Appraiser RZ 1666

Donald G. Blauvelt, MAI, SRA
State-Certified General Real Estate Appraiser RZ 511

EC HEARING EXHIBIT - 00000474

A SUMMARY APPRAISAL
OF A 46-ACRE
UNDEVELOPED TRACT OF LAND

LOCATED ON
THE NORTHWEST SIDE OF COURTENAY PARKWAY
(SR 3), ABUTTING THE AIR LIQUIDE INDUSTRIAL PLANT,
ON MERRITT ISLAND IN UNINCORPORATED
BREVARD COUNTY, FLORIDA

PREPARED FOR
FP&L CORPORATE REAL ESTATE
700 UNIVERSE BOULEVARD
JUNE BEACH, FL 33406

AS OF
JANUARY 17, 2008

APPRAISERS

PHILIP M. HOLDEN, MAI
STATE-CERTIFIED GENERAL REAL ESTATE APPRAISER RZ 1666
AND
DONALD G. BLAUVELT, MAI, SRA
STATE-CERTIFIED GENERAL REAL ESTATE APPRAISER RZ 511

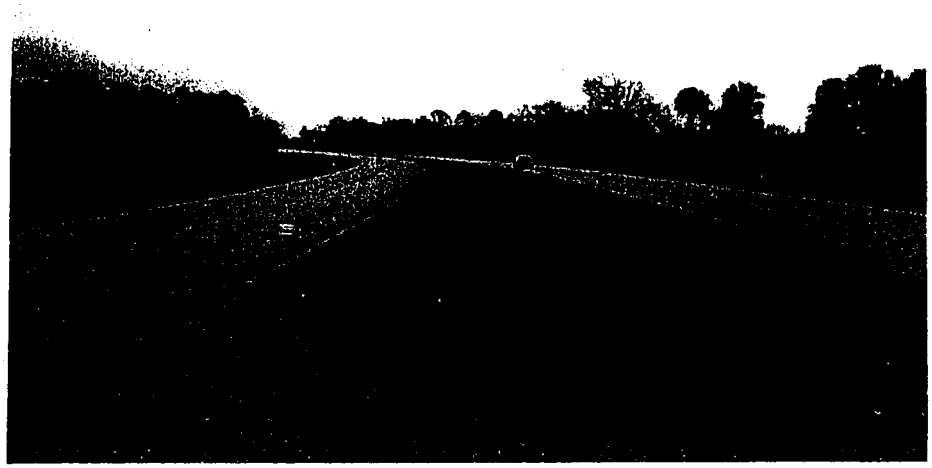
S. F. HOLDEN, INC.
8259 NORTH MILITARY TRAIL, SUITE 10
PALM BEACH GARDENS, FLORIDA 33410

JOB NO. 2324

ECRC 08-682
HEARING EXHIBIT - 00000475

SUBJECT PHOTOS

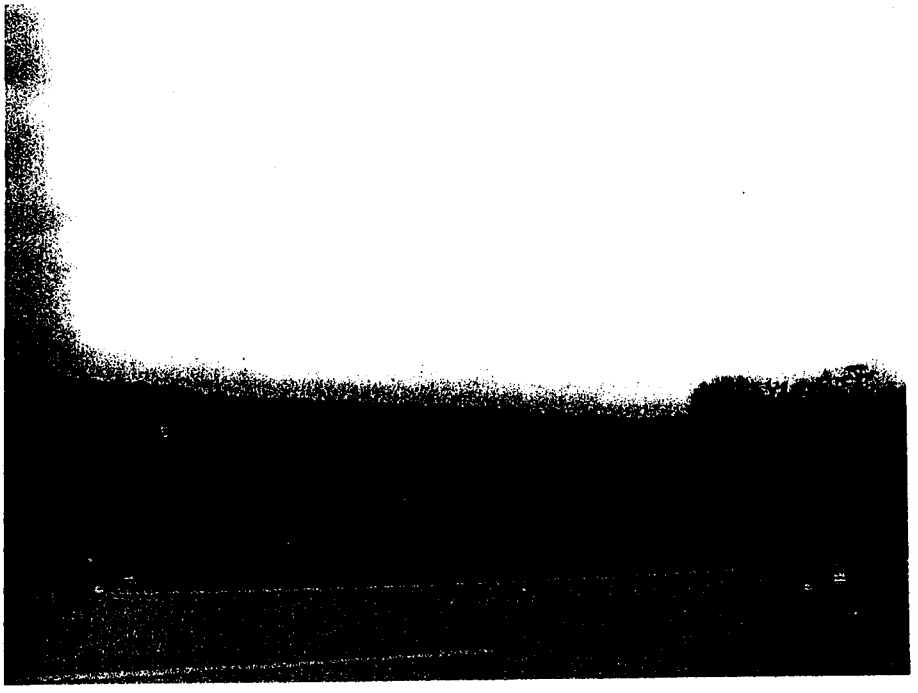
View southwest along Courtenay Parkway with subject property picture right. NASA press reception center is in far background.



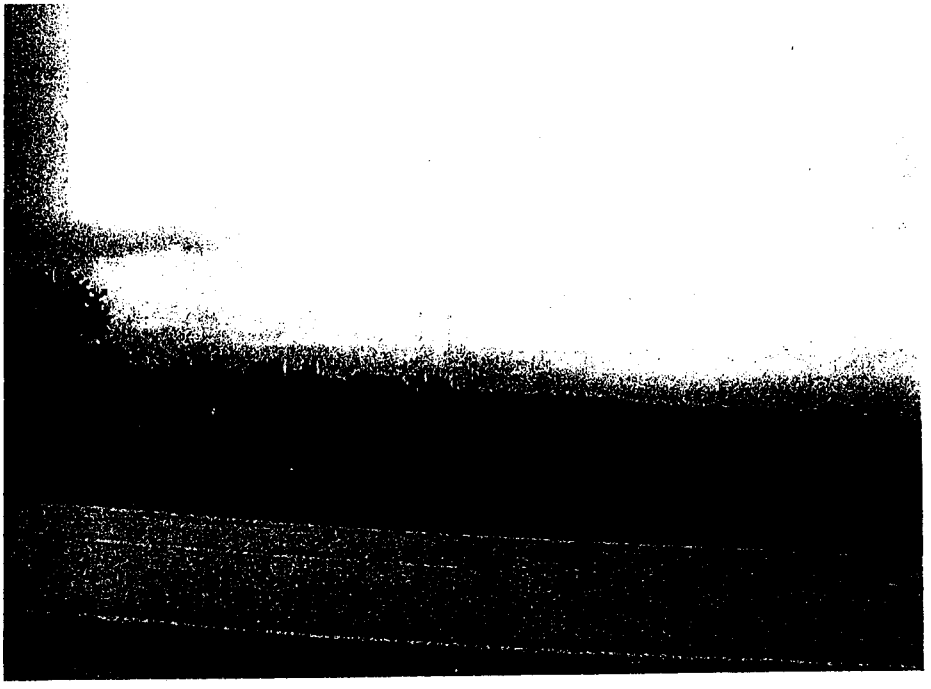
Reverse northeast view along Courtenay Parkway from the property location

ECR-CARING
HEARING EXHIBIT - 00000476

SUBJECT PHOTOS



Looking north along the east side of the property



View northwest across the southern end of the property from Courtenay Parkway

ECBC 08-0084
HEARING EXHIBIT - 00000477

SUBJECT PHOTOS

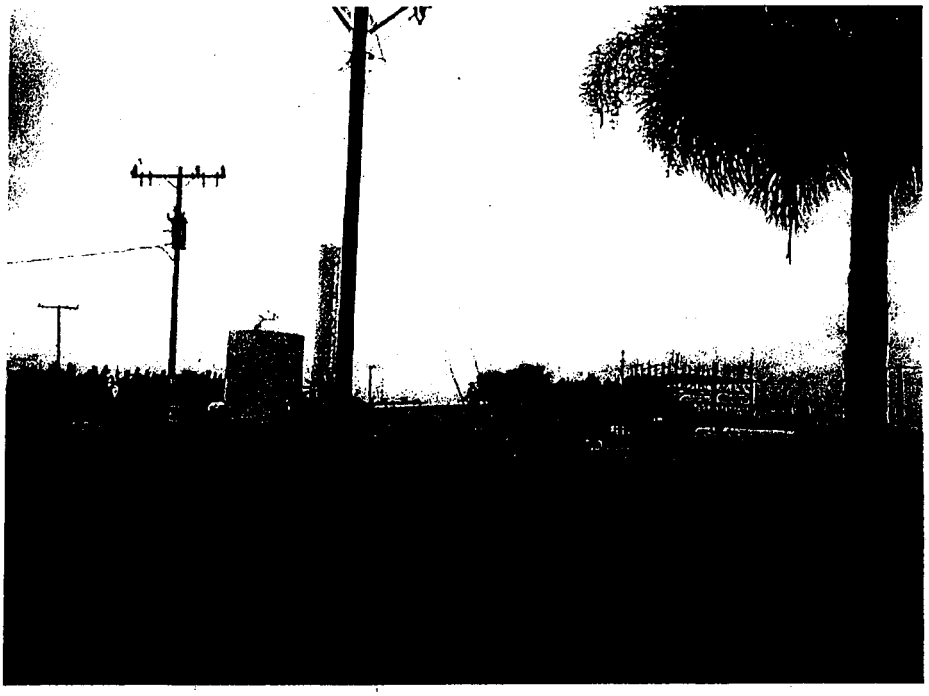
Representative internal view through the property

Looking west along the proposed north line of the property, with the north end of the subject picture left

ECRO-08005
HEARING EXHIBIT - 00000478

SUBJECT PHOTOS

Existing power line corridor inside the west line of the property



View of the Air Liquide industrial plant to the immediate west of subject property

ECRC 08-(8)
HEARING EXHIBIT - 00000479

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ADDENDA

Sale Write-Ups
1988 Comprehensive Plan, Industrial Zoning Categories
Qualifications

EC HEARING EXHIBIT - 00000480

INTRODUCTION

HEARING EXHIBIT - 00000481

EXECUTIVE SUMMARY

Property Location	The northwest side of Courtenay Parkway (S.R. 3) along and within the south boundary of the NASA Kennedy Space Center campus, adjoined on the west side an Air Liquide industrial plant, on Merritt Island in unincorporated Brevard County, Florida. Brevard County identifies the property as being 7110 North Courtenay Parkway, Merritt Island, Florida 32953.
County	Brevard County, Florida
Owner of Record	United States Government
Interest Appraised	Fee simple estate
Primary Influences	The property is just inside the south boundary of the 140,000-acre NASA Kennedy Space Center. Only 5% of the associated land is developed with facilities with the balance undeveloped and managed by the U.S. Fish and Wildlife Service as part of the Merritt Island Natural Wildlife Refuge. The appraised property is an old citrus grove operated under license from the Fish & Wildlife Service. An existing electrical power line is within and parallel to the west line of the property and serves the privately owned Air Liquide facility to the immediate west, which is outside the space center land ownership.
Dates	Date of Last Inspection January 17, 2008 Date of Value January 17, 2008 Date of Report January 31, 2008
Land Size and Shape	Rectangular shaped 46.0 acres (see Extraordinary Assumption 1).
Improvements	No buildings are on the property. The existing citrus grove improvements consist of swales, perimeter and internal drainage ditches, wells and pump station, etc.
Utilities	A municipal water line is located along SR 3. Sanitary sewer is located approximately one mile to the north inside the gated environment of the space center. Electricity is currently to the property as part of the citrus grove facilities (well pumps, etc.)

EGRDA08-KSN HEARING EXHIBIT - 00000482

EXECUTIVE SUMMARY (Continued)

Soil Types	Copeland-Bradenton-Wabasso complex, limestone substratum (80.3%) and Bradenton fine sand, limestone substratum (19.7%).
FLUP/Zoning	The land is subject only to those uses that would be permitted by NASA and the Kennedy Space Center. According to Mr. Jim Ball, Real Estate Director, NASA has been exploring development of a 320-acre area of existing citrus groves north of the appraised property as a potential light industry technology center, tentatively called Exploration Park. The land would be leased to a private developer who would develop the necessary land infrastructure (water, sewer, interior roads, etc.) as well as vertical structures that would be leased to end-users complimentary and beneficial to the space center. At present, this proposed project is on hold.
Concluded Highest and Best Use of the Land	As a potential light industrial site providing support services to the space center (see Extraordinary Assumption #2).
Market Value Conclusion	Sales Comparison Approach $3,450,000 Value per gross acre $75,000
Paraphrased Extraordinary Assumptions	1. We have relied on the represented size of the property as being 46.0 acres. 2. As the property is part of federally-owned land and NASA has not reduced to writing the uses to which the property will be limited, we have assumed that the permitted uses would be a reasonable mixture of those uses permitted by Brevard County's PBP, PIP and I-U industrial zoning categories. If NASA limits the uses to which the property may be used materially less than the comparative uses permitted under the three mentioned county zoning classifications, our estimate of value may require reconsideration.

ECRC-08-600 HEARING EXHIBIT - 00000483

EXECUTIVE SUMMARY (Continued)

Appraisers	S. F. HOLDEN, INC. 8259 North Military Trail, Suite 10 Palm Beach Gardens, FL 33410 Philip M. Holden, MAI State-Certified General Real Estate Appraiser RZ1666 Donald G. Blauvelt, MAI, SRA State-Certified General Real Estate Appraiser RZ511

EC HEARING EXHIBIT - 00000484

CERTIFICATION

We certify that, to the best of our knowledge and belief:

1. The statements of fact contained in this report are true and correct.

2. The reported analyses, opinions and conclusions are limited only by the reported assumptions, limiting conditions, and legal instructions, and our personal, impartial, and unbiased professional analyses, opinions and conclusions.

3. We have no present or prospective interest in, or no bias with respect to, the property that is the subject of this report, and we have no personal interest or bias with respect to the parties involved.

4. Our engagement in this assignment was not contingent upon developing or reporting predetermined results.

5 Our compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal.

6. We have made a personal inspection of the property that is the subject of this report from offsite only, and did not contact the property owner, and his/her designated representative.

7. No one provided significant professional assistance to the persons signing this report.

8. The use of this report is subject to the requirements of the State of Florida relating to review by the Florida Real Estate Appraisal Board.

9. The use of this report is subject to the requirements of the Appraisal Institute relating to review by its duly authorized representatives.

10. The reported analyses, opinions and conclusion were developed, and this report was prepared, in conformity with the requirements of the Code of Professional Ethics and Standards of Professional Appraisal Practice of the Appraisal Institute, which include the Uniform Standards of Professional Practice.

11. That we have not revealed the results of such appraisal to other than the proper officials of Florida Power & Light or its designated agents and will not do so until authorized by same, or until required by due process-of-law, or until release from this obligation by having publicly testified as to such results.

ECRC 08-(02)
HEARING EXHIBIT - 00000485

CERTIFICATION (Continued)

12. As of the date of this report, Philip M. Holden and Donald G. Blauvelt have completed the continuing education program of the Appraisal Institute.

Philip M. Holden, MAI
State-Certified General Real Estate Appraiser RZ 1666

Donald G. Blauvelt, MAI, SRA
State-Certified General Real Estate Appraiser RZ 511

FOR CPN 43
HEARING EXHIBIT - 00000486

GENERAL UNDERLYING ASSUMPTIONS

1. The legal description used in this report is assumed to be correct.

2. No survey of the property has been made by the appraiser and no responsibility is assumed in connection with such matters. Sketches in this report are included only to assist the reader in visualizing the property.

3. No responsibility is assumed for matters of a legal nature affecting title to the property nor is an opinion of title rendered. The title is assumed to be good and merchantable.

4. Information furnished by others is assumed to be true, correct, and reliable. A reasonable effort has been made to verify such information; however, no responsibility for its accuracy is assumed by the appraiser.

5. All mortgages, liens, encumbrances, leases and servitudes have been disregarded unless so specified within the report.

6. The property is appraised as though under responsible ownership and competent management.

7. It is assumed that there are no hidden or unapparent conditions involving the property, subsoil, or structures that would render it more or less valuable. No responsibility is assumed for such conditions or for tests that may be required to discover such factors.

8. It is assumed that there is full compliance with all applicable local, state, and federal environmental regulations and laws unless noncompliance is stated, defined, and considered in the appraisal report.

9. It is assumed that all applicable zoning and use regulations and restrictions have been complied with, unless a non-conformity has been stated, defined, and considered in the appraisal report.

10. It is assumed that all required licenses, consents, or other legislative or administrative authority from any local, state, or national governmental or private entity or organization have been or can be obtained or renewed for any use on which the value estimate contained in this report is based.

11. It is assumed that the utilization of the land and existing or proposed improvements is within the boundaries of the property lines of the property described and there is no encroachment or trespass unless noted within the report.

ECRC 08-(01
HEARING EXHIBIT - 00000487

GENERAL UNDERLYING ASSUMPTIONS (Continued)

12. No consideration is given to oil, gas or mineral rights, which are assumed to be included in the fee simple title, or whether the property is subject to surface entry for the exploration or removal of such materials except as is expressly stated.

13. No consideration is given to the fauna or flora life that may exist on a property and cause a loss in value of use due to their presence.

14. Unless otherwise stated in this report, the existence of hazardous substances, including, but not limited to, asbestos, polychlorinated biphenyls, petroleum leakage, or agricultural chemicals which may be present on the property, or other environmental conditions which were not called to the attention of the appraiser or of which the appraiser did not become aware during the inspection are assumed not to exist. The appraiser has no knowledge of the existence of such materials on or in the property unless otherwise stated. The appraiser, moreover, is not qualified to test such substances or conditions. The presence of these or other hazardous substances or environmental conditions may affect the value of the property. However, the value estimated herein is predicated on the assumption that no such conditions exist on or in the property or in such proximity thereto that they would cause a loss in value. No responsibility is assumed for any such conditions nor for any expertise or engineering knowledge required to discover them.

15. A limited soil study or information relating to geologic conditions covering the subject property was made available to the appraisers. It is assumed that the portions of the appraised property that are considered developable uplands contain soil conditions capable of supporting residential development without extraordinary foundation or soil remedial expenses.

16. We have assumed there are no significant environmental issues regarding wetlands and the existing drainage is/could be made adequate to accommodate typical industrial/business park development.

EMINENT DOMAIN HEARING EXHIBIT - 00000488

EXTRAORDINARY ASSUMPTIONS

Extraordinary Assumption is defined as follows:

> An assumption, directly related to a specific assignment, which, if found to be false, could alter the appraiser's opinions or conclusions. Extraordinary assumptions presume as fact otherwise uncertain information about physical, legal, or economic characteristics of the subject property; or about conditions external to the property, such as market conditions or trends; or about the integrity of data used in an analysis. [1]

This appraisal is based on the following Extraordinary Assumptions.

1. No formal survey of the property is available and the property's size of 46.0 gross acres is based on calculations made by NASA personnel at the Kennedy Space Center. We have assumed this size accurately reflects the land being considered by our client and have relied on this size in our valuation.

2. NASA is proposing a long-term ground lease of the property to FP&L, but limitations on the use of the land (type of permitted uses) have not been reduced to writing and available for formal consideration in our appraisal. NASA, the Kennedy Space Center and the Fish & Wildlife Service will dictate the uses deemed appropriate as no local zoning and land use regulations apply within the federal government ownership. We have assumed that the property will have a mixture of comparative permitted uses as those found in Brevard County's three primary industrial zoning classifications (PBP, PIP and I-U). If the uses under NASA are restricted or materially less than those uses permitted in the latter three Brevard County zoning classifications, our estimate of value would require reconsideration. (For expanded discussion on this assumption, see Land Use Plan/Zoning and Highest and Best Use sections in the report.)

1 USPAP 2006 Edition, The Appraisal Foundation.

EGRC 08/06 HEARING EXHIBIT - 00000489

GENERAL LIMITING CONDITIONS

1. With reference to the property, the appraiser will not be required to give testimony or to appear in court because of having made this appraisal, unless arrangements have been previously made.

2. Possession of this report, or a copy thereof, does not carry with it the right to publication. It may not be used for any purpose by any person other than the party to whom it is addressed without the written consent of the firm and, in any event, only with proper written qualifications and only in its entirety.

3. The distribution of the total valuation in this report between land and improvements applies only under the reported highest and best use of the property. The value for this property and/or allocations of values for land and improvements must not be used in conjunction with any other appraisal or property and are invalid, if so used.

4. Real estate investments have an inherent element of risk which varies with property classification and other factors which affect value. Performance and success are dependent upon many variables such as responsible ownership, competent management, the state of the economy, federal, state and local tax laws, market liquidity, and other factors of a local, national or world character which influence the market. Consequently, this value estimate does not absolutely fix or set the price at which the property will sell. It merely states a probable selling price under the conditions set forth in the definition of market value. The projections set forth herein are based on anticipated or stated conditions, and as such represent the judgment of the appraisers, and must be considered in this context.

5. Neither all nor any part of the contents of this report, or copy thereof, shall be conveyed to the public through advertising, public relations, news, sales or any other media without written consent and approval of the appraiser. Nor shall the appraiser, firm, or professional organization of which the appraiser is a member be identified without written consent of the appraiser.

6. No environmental impact studies were requested or made in conjunction with this analysis, and the appraiser hereby reserves the right to alter, amend, revise or rescind any of the value opinions based upon any subsequent environmental impact studies, research or investigation.

7. Easements are most likely described in Title Policies for property. A current survey and/or title search is recommended to determine the existence of easements, encroachments, restrictions, and reservations.

EDRC 08-697 HEARING EXHIBIT - 00000490

GENERAL LIMITING CONDITIONS (Continued)

Easements may or may not be recorded or may exist by customary use or other legal means. The appraisers have not, and are not qualified to, search legal records as to other easements. Because rights of others can have influence on real estate values, the values reported herein are predicated on a qualified legal opinion that the assumption above regarding easements and the rights of others is representative of actual conditions.

Acceptance of and/or use of this report constitutes acceptance of the foregoing General Underlying Assumptions, Extraordinary Assumptions, and General Limiting Conditions. Appraiser's liability extends only to the stated client, not subsequent parties or users, and limited to the amount of fee received by appraisers.

EXHIBIT - 00000491

GENERAL INFORMATION

OUR CLIENT

S.F. Holden, Inc. was engaged by Mr. Tim Corson with FP&L Corporate Real Estate to prepare an appraisal of the herein described property.

INTENDED USE AND USER OF THE APPRAISAL

The intended user of this appraisal is our client for the purpose of establishing the market value of the property for possible long-term lease.

PURPOSE, DATE AND INTEREST OF THE APPRAISAL

The purpose of our appraisal is to estimate the market value of the fee simple estate of the property as of January 17, 2008, the last date of formal inspection.

SCOPE OF WORK

An appraiser's *Scope of Work* involves designing a plan of investigation and analysis that leads to a valuation that answers the client's reason for and intended use of the resulting appraisal. In order to estimate the market value of the appraised property, we:

- analyzed the physical, legal and economic characteristics of the property and analyzed its supporting neighborhood,
- estimated the property's highest and best use,
- contacted NASA officials regarding the physical and legal factors impacting the property as well as various people in the public and private sector involved in real estate transactions, including real estate brokers, other real estate appraisers and buyers and sellers knowledgeable regarding local conditions and real estate transactions, and
- since the property is undeveloped land we have utilized only the sales comparison approach. This approach involved researching comparable unencumbered land sales in the relevant market area and applying appropriate adjustments.

EXHIBIT - 00000493

DEFINITIONS

Market Value is defined as:

Market value is the major focus of most real property appraisal assignments. Both economic and legal definitions of market value have been developed and refined. A current economic definition agreed upon by agencies that regulate federal financial institutions in the United States of America is:

> The most probable price which a property should bring in a competitive and open market under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus. Implicit in this definition is the consummation of a sale as of a specified date and the passing of title from seller to buyer under conditions whereby:
>
> 1. Buyer and seller are typically motivated;
> 2. Both parties are well informed or well advised, and acting in what they consider their own best interests;
> 3. A reasonable time is allowed for exposure in the open market;
> 4. Payment is made in terms of cash in United States dollars or in terms of financial arrangements comparable thereto; and
> 5. The price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale. [2]

Fee Simple Estate is defined as:

> Absolute ownership unencumbered by any other interest or estate, subject only to the limitations imposed by the governmental powers of taxation, eminent domain, police power, and escheat. [3]

2 The Dictionary of Real Estate Appraisal, Fourth Edition, Appraisal Institute, 2002.
3 Ibid.

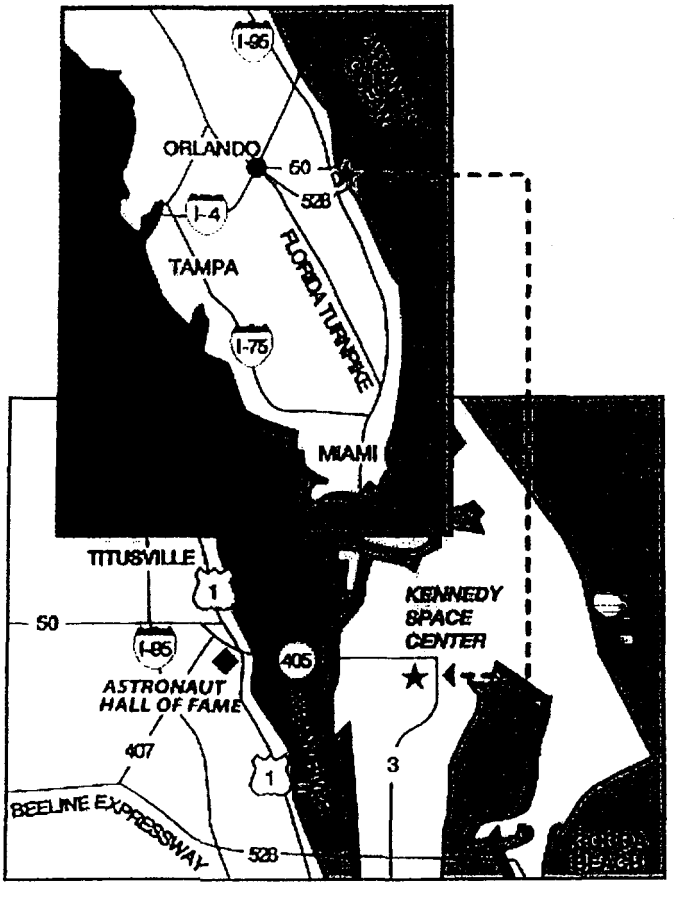
EDR HEARING EXHIBIT - 00000494

PRESENTATION OF DATA

EQR-00-TN2 HEARING EXHIBIT - 00000495

NEIGHBORHOOD ANALYSIS

The appraised property is part of the U.S. National Aeronautical and Space Administration's (NASA) Kennedy Space Center, which encompasses 140,000 acres of federally-owned land in northeast Brevard County, Florida. The space center encompasses the whole of northern Merrit Island north to the Brevard-Volusia county line as well as the associated east coast line of Florida. The Kennedy Space Center is the principal home of the U.S. space shuttle program and principal site of the United State's civilian and military space launch facilities. The popular visitor center outside of the space center's secured environment is Florida's fourth highest revenue generating tourist attraction.



The 140,000 acres of the space center extend west from the barrier island along the Atlantic Ocean, across the Banana River bay to the west side of northern Merritt Island. The City of Titusville is northwest of the space center across the wide Indian River bay that separates Merritt Island from Florida's mainland. The City of Cocoa on the mainland is southwest of the Kennedy Space Center.

HEARING EXHIBIT - 00000496

NEIGHBORHOOD ANALYSIS (Continued)

Two principal access routes are available to the Kennedy Space Center. The western route is via several highways that converge south of Titusville for connection to S.R. 405 across the Indian River onto Merritt Island. These routes are either directly from Interstate 95 or the northeast extension of S.R. 528 east from Orlando. The Astronaut Hall of Fame attraction is located along S.R. 405 on the west side of the Indian River while the space center's large visitor and tourist attraction center is along S.R. 405 on Merritt Island west of a gated entry into the secured portion of the space center.

The second access route is also via S.R. 528 as it continues east from its connection with Interstate 95 to the City of Cocoa on its way across the middle of Merritt Island to the coastal community of Cocoa Beach, Port of Canaveral and Canaveral Air Force Base on Florida's coast. Courtenay Parkway (S.R. 3) is the principal north-south traffic arterial through the whole of Merritt Island and connects to S.R. 528 approximately nine miles south of the southern Merrit Island gate entrance into the space center.

LEGAL DESCRIPTION OF THE PROPERTY

No legal description has been provided. The property is part of a 480-acre parcel of land located in Section 13, Township 23 South, Range 36 East, of Brevard County, Florida, identified by the Brevard County Property Appraiser under folio number 23-36-13-00-00001.0-0000.00. Although vacant land, the address assigned by the Brevard County Address Assignment Office is 7110 North Courtenay Parkway, Merritt Island, Florida 32953.

OWNERSHIP HISTORY

The appraised property is part of the 140,000-acre Kennedy Space Center in northeast Brevard County, Florida, the entire land holdings being owned by the U.S. Federal Government. The associated land has been under government ownership for more than 30 years.

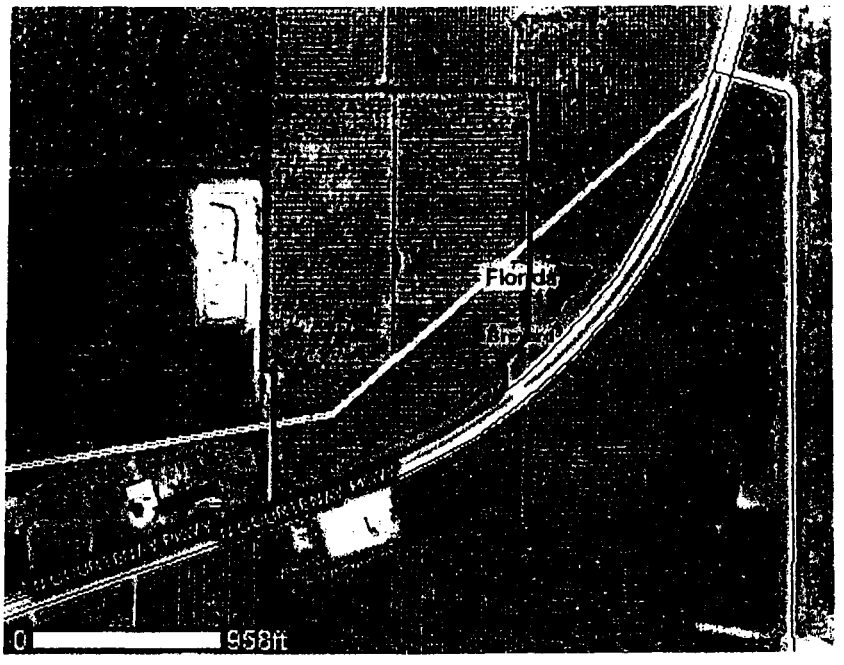
DESCRIPTION OF THE PROPERTY

The appraised property is located along the northwest side of North Courtenay Parkway (SR 3), adjacent to the boundary of the Kennedy Space Center campus on Merrit Island. Courtenay Parkway is a four-lane divided highway with wide center grassed median at the property location.

The property is rectangular-shaped and represented to consist of 46.0 gross acres. It is currently improved with an old citrus grove bounded on the east and north sides by drainage ditches and agricultural-oriented field road used for machinery access during citrus harvests.

EXHIBIT - 00000497

DESCRIPTION OF THE PROPERTY (Continued)



The property is generally flat and level and at the relative finished grade of Courtenay Parkway. According to the USDA Natural Resource Center, the property's soil mix is summarized in the following table:[4]

Soil Classification

Unit Symbol	Unit Name	Acres	%
16	Copeland-Bradenton-Wabasso complex, limestone substratum	39.7	80.2%
8	Bradenton fine sand, limestone substratum	9.8	19.8%
Totals		49.5	100.0%

USDA, Natural Resource Center, Web Soil Survey

According to FEMA community panel 125092-0285E, dated April 3, 1989, the property is in an "X", or undetermined, flood zone.

4 The difference between the 46.0 acre size represented by the client and the 49.5 acre size estimated by the USDA Soil Survey results from the USDA web-based system requiring an "area of interest" to be drawn using the provided sketch function along the approximate boundaries of a property. The result may or may not match the actual boundary and area under appraisal. Therefore, this table is shown for informational purposes only as to the gernal division of the property's soil classifications.

DESCRIPTION OF THE PROPERTY (Continued)

Public electricity is developed to the property and telephone service is available but not developed to the property. While municipal water is located along S.R. 3 at the property's location, the nearest municipal sewer line is approximately 1+ mile north on Courtenay Parkway, inside the secured environment of the Kennedy Space Center.

ABUTTING OR IMMEDIATE AREA USES

The property is bordered on its west side by an Air Liquide industrial plant that fronts the northerly side of Courtenay Parkway. This is a French company headquartered in Paris and second on the world market in its field. The company supplies industrial gases and services to various industries including medical, chemical and electronic manufacturers. It operates in over 70 countries with major sites in Japan as well as Houston, Texas and Newark, Delaware in the U.S. Its presence adjacent to the Kennedy Space Center is for supplying various gases used in NASA's space program. This property is located on land outside of the federally-owned space center campus.

The north and east sides of the property consist of additional citrus groves under license from the U.S. Fish and Wildlife Service. South across Courtenay Parkway from the southwest corner is a small one-story NASA reception center. This center is used for issuing press credentials during space shuttle launches, provides limited office space for contractors working for NASA, a conference room for meetings outside the gated environment of the space center.

For a distance of approximately one mile north of the property to the Courtenay Parkway security entrance into the gated environment of the space center, the land is either undeveloped in nature vegetation or old citrus groves. For approximately two miles west along S.R. 3 from the property the land is predominantly older citrus groves interi..ixed with sparse single family homes on rural acrea_es.

FLORA, FAUNA AND WILDLIFE ISSUES

No report by a biologist or environmental scientist is available and our valuation has assumed that the property is not inhabited by endangered or protected wildlife. Considering that the property is developed as a grove, environmental issues will likely be minimal.

ECRC-08-706
HEARING EXHIBIT - 00000499

EASEMENTS AND ENCROACHMENTS

An apparent electric power line easement, the width of which was not available, runs south-to-north along the west inside line of the property. This corridor serves the Air Liquide plant to the immediate west of the property.

We did not notice and are not aware of any apparent encroachment into the property from adjacent land uses.

PROPERTY ASSESSMENT AND TAXES

In Florida, all property is assessed on a 100% fee simple basis. The subject property is identified as being part of a 480-acre tax parcel under tax folio number 23-36-13-00-00001.0-0000.00. This 480-acre and inverted "L" shaped parcel includes land on both sides of Courtenay Parkwark comprised of native lands, wetlands and licensed citrus groves as well as the previously described small reception center. For calendar 2007 this parcel was assessed at a "just value" of $7,200,000, or $15,000 per acre.

Since the U.S. Government is this tax parcel's owner and not liable for the payment of property taxes, the property appraiser's estimated "just value", as derived by a computer-assisted mass appraisal program, does not bear reference to the property's true market value. As a consequence, no correlation between the county property appraisers "just value" and our estimate of the property's fee simple market value is anticipated.

LAND USE PLAN AND ZONING LIMITATIONS

In the State of Florida, county and municipal land use plans versus zoning limit the level of intensity to which a property may be developed. Unless a land use classification is changed or amended, a property's zoning classification cannot exceed the uses permitted by the adopted land use plan. Conversely, because the 140,000 acre Kennedy Space Center is owned by the federal government, the broad land use in the space center is subject only to those limitations imposed by NASA, the U.S. Fish & Wildlife Service and related federal agencies having jurisdiction over the space center's land. No municipal or county land use or zoning regulations apply within the boundary of the Kennedy Space Center.

According to discussions with Jim Ball, NASA's representative regarding the appraised property, NASA has been seeking to maximize the use of approximately 320 acres presently in marginally productive citrus groves (operated under license from the U.S. Fish & Wildlife Service) west of S.R. 3 north of the subject property. To be known as Exploration Park, the intent is to lease for a base period of 50 years 320 acres to a master developer who would develop all of the necessary horizontal land infrastructure (internal roads, utility system, etc.) then develop vertical buildings leased to businesses and vendors supporting the activities of the space center as its transitions in 2009 and

E HEARING EXHIBIT - 00000500

LAND USE PLAN AND ZONING LIMITATIONS (Continued)

2010 from its current shuttle oriented space program to a more diversified spaceport for the NASA Orion Crew Exploration Vehicle coupled with both military and increased commercial launch activities to the International Space Station.

According to the RFP prepared in late 2006 and provided for our review, upwards of 2 million SqFt of buildings are envisioned. At present, this proposal is on hold.

Since there are no sales of similar vacant properties within the NASA ownership, it is necessary to use sales of vacant land sold outside of the Kennedy Space Center as the basis of market value. We have reviewed Brevard County's industrial zoning categories as reference for the potential use of the subject property. Under the county's 1988 Comprehensive Plan there are four standard industrial zoning categories: Planned Business Park (PBP), Planned Industrial Park (PIP), Light Industrial (IU), and Heavy Industrial (IU-1). Of these four, the first three are applicable for consideration and briefly described below.

Planned Business Park (PBP) zoning classification is intended to encourage compatible development within areas designated community commercial and planned industrial on the future land use map of the county comprehensive plan.

- The minimum park size is five acres with a minimum divided lot size of one-half acre.
- Permitted uses are all those uses in the BU-1 and BU-2 zoning categories and hotels and motels, limited to 30 units per acre.
- Permitted accessory uses primarily intended for employees and visitors and located entirely within a principle building are branch banks, credit unions and post offices; cafeterias or snack bars; exhibition halls specifically related to the principal use of the property, and retail sales limited to the sale of sundries, stationery, office supplies and similar goods and the sale of products and materials manufactured on the premises (which shall not exceed five percent of the gross floor area).
- Permitted uses with conditions are a single family residence.
- Conditional uses include marinas, commercial or recreational, and towers and antennas.
- Depending on the abutting land use (zoning), the maximum achievable building height is 45 feet.

Planned Industrial Park (PIP) zoning is intended for locations which are served by major roads but are not feasible for light or heavy industrial developments because of proximity to residential uses. The regulations for this district are intended to encourage development compatible with surrounding or abutting residential districts, with suitable open spaces, landscaping and parking areas. Manufacturing activities that can be carried on in a relatively unobtrusive manner, and certain facilities that are necessary to serve the employees of the district, are permitted.

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HEARING EXHIBIT - 00000501

LAND USE PLAN AND ZONING LIMITATIONS (Continued)

- The minimum land size is three acres with a minimum divided lot size of one acre.
- Permitted uses are all those uses in the BU-1 and BU-2 zoning categories and motels.
- Permitted uses with conditions are a boatbuilding facility, recovered materials processing facility and single family residence.
- Customary accessory uses are permitted, including operations required to maintain or support any use permitted in this zone on the same lot as the permitted use, such as maintenance shops, and machine shops, provided these take place within enclosed buildings. In addition, uses permitted as a convenience to the occupants thereof and their customers and employees are convention or exhibit hall, dining and recreational facilities.
- Conditional uses include commercial/industrial marina and towers and antennas.
- Depending on the abutting land use (zoning), the maximum achievable building height is 45 feet.

Light Industrial (I-U) zoning is intended for areas in which the principal use of land is for manufacturing, assembling and fabrication, and for warehousing. These uses do not depend primarily on frequent personal visits of customers or clients, but usually require good accessibility to major rail, air or street transportation routes.

- The minimum lot size is 20,000 SqFt.
- Permitted uses are all those uses in the BU-1 and BU-2 zoning categories, except, single family residence.
- Permitted uses with conditions are assisted living facilities; commercial entertainment and amusement enterprises (small scale); power substations and transmission facilities; recovered materials processing facility.
- Customary accessory uses are permitted, including operations required to maintain or support any use permitted in this zone on the same lot as the permitted use, such as maintenance shops, and machine shops, provided these take place within enclosed buildings. In addition, uses permitted as a convenience to the occupants thereof and their customers and employees are convention or exhibit hall, laundry, dining and recreational facilities. Also roadside stands used for the sale of agricultural produce and security trailers.
- Condition uses are alcoholic beverages for on-premises consumption; commercial entertainment and amusement enterprises (large scale); commercial/recreational and commercial/industrial marina; composting and/or mulching facility; flea markets (recreational vehicles); motocross; towers and antennas; truss manufacturing plant.
- Depending on the abutting land use (zoning), the maximum achievable building height is 60 feet.

EXHIBIT - 00000502

LAND USE PLAN AND ZONING LIMITATIONS (Continued)

The permitted uses in the "BU-1" and "BU-2" zoning categories, which form the basic uses permitted in all three of the described industrial categories, are essentially retail/commercial uses associated with freestanding retail businesses and shopping centers, office buildings, automotive centers, gasoline service stations, etc. One of the "permitted uses with conditions" in both the BU-1 and BU-2 zoning categories is "substations, and transmission facilities."

ECUBE CORP
HEARING EXHIBIT - 00000503

ANALYSIS AND CONCLUSIONS

HIGHEST AND BEST USE

Highest and best use may be defined as:

> "The reasonably probable and legal use of vacant land or an improved property, which is physically possible, appropriately supported, financially feasible, and that results in the highest value." [5]

The four criteria the highest and best use must meet are legally permissible, physically possible, financially feasible, and maximally productive.

1. "Legally Permissible: In all cases the appraiser must determine which uses are legally permissible. Private restrictions, zoning, building codes, historic district controls, and environmental regulations must be investigated because they may preclude many potential uses.

2. Physically Possible: The size, shape, area, terrain, and accessibility of a parcel of land and the risk of natural disasters such as floods or earthquakes affect the uses for which it can be developed.

3. Financially Feasible: In determining which uses are legally permissible and physically possible, an appraiser eliminates some uses from consideration. Then the uses that meet the first two criteria are analyzed further. If the uses are income-producing, the analysis will study which are likely to produce an income, or return, equal to or greater than the amount needed to satisfy operating expenses, financial obligations, and capital amortization.

4. Maximally Productive: Of the financially feasible uses, the use that produces the highest residual land value consistent with the rate of return warranted by the market for that use is the highest and best use." [6]

5 The Appraisal of Real Estate, Twelfth Edition, Appraisal Institute, 2001.
6 Ibid.

ECR 03-07 HEARING EXHIBIT - 00000505

HIGHEST AND BEST USE (Continued)

Analysis and Conclusion

NASA does not have the right to sell land to non-government interests within the boundary of the Kennedy Space Center, but may lease the land on a short or long-term basis to a private user. Accordingly, NASA has offered the appraised property to our client under a proposed long-term lease. After examining those factors explicit in the determination of a property's highest and best use, it is our judgment that the property's highest and best use is for some form of industrial-related development compatible with and beneficial to NASA and the Kennedy Space Center.

Conceptually, owners of real property who hold the 100% fee simple interest in property are entitled to fully enjoy all the uses that property may be developed to unless limited by government's imposition of land use regulations and zoning ordinances. However, depending on an individual property's particular characteristics (e.g., location, access, market conditions at a given point in time, etc.) not all of the rights of use permitted by zoning may have equal value or be appropriate for development.

As of the date of our valuation, the uses that NASA will allow have not been put into a written document and no ready comparison can be made to the rights of use embodied by zoning associated with the sales used in our valuation. We are informed that the space center's visitor center north of the subject ranks as the fourth highest tourist revenue center in Florida, exceeded only by Disney World, Sea World and the like in Orlando. NASA's future plans for the visitor center include developing a hotel and such use will not be permitted at the subject property. In addition, uses that would compete with or be incompatible to the proposed 320-acre Exploration Park will not be permitted. However, what the potential competing and incompatible uses are have not been determined as the full extent of the proposed Exploration Park has not been determined.

The above discussion is intended to illustrate that although our client intends to use the subject property for a specific purpose, market value requires consideration of all of the uses to which property may be used. If NASA limits the permitted uses that the subject may be used in addition to that which the client intends to use the property for, consideration of a discount from our estimate of the land's market value would be appropriate.

HEARING EXHIBIT - 00000506

THE APPRAISAL PROCESS

The appraisal process is an orderly program in which data used to estimate the value of a property is acquired, classified, analyzed, and presented. This is accomplished through the use of one or more of the three appraisal approaches; namely the cost, sales comparison and income approaches.

The basis of the three approaches to value is the principle of substitution, which affirms that a prudent purchaser has three alternatives available; either to buy a vacant parcel of land and develop a similar property (cost approach), acquire an equally desirable existing property offering comparable utility (sales comparison approach), or acquire a substitute income stream of comparable quality, quantity, and durability (income approach). Since the property being appraised is undeveloped land, the sales comparison approach is the only applicable method of valuation and has been utilized in our valuation.

Following the general decline of Florida's residential real estate market by early 2006, the commercial and industrial market appears to have materially declined in activity by early 2007. During the course of this appraisal, we had discussions with numerous participants in Brevard County's industrial real estate market, including with buyers and sellers, real estate brokers, county property appraiser personnel and other independent appraisers. While numerous transactions were considered, many were not appropriate for comparison due to unrealistic size differences from the subject property, sold when the market was materially superior in sale conditions, had significantly more intense zoning and use capabilities, were physically more developed than the subject property, or were materially distance from the nearest population center.

Consequently, the data selected for comparison is judged the most appropriate, geographically closest and most indicative of past market activity. The selected data also includes a current listing of industrially-zoned land of relatively comparable size located in the S.R. 3 corridor on Merritt Island south of the subject property.

Except for the listing, all of the closed sales utilized sold in the open and public market as arms-length transactions and did not involve seller financing requiring cash-equivalent considerations. The sales also occurred since the beginning of calendar 2006, but each requires consideration of a possible adjustment to reflect current slower market conditions.

The transaction data was further analyzed and compared in regards to general location, size and shape, access, highway exposure, zoning and availability of utility systems. The relative comparability of each transaction characteristic was compared using a qualitative analysis, which ascribes a quality factor of similar, superior, or inferior for each sale characteristic. If the characteristic of the sale is similar to that of the appraised

ECRC 08-714
HEARING EXHIBIT - 00000507

THE APPRAISAL PROCESS (Continued)

property, no consideration is given and is considered a neutral adjustment. An inferior characteristic would require a positive (upward) adjustment to be made to the sale to make it similar to the subject if dollar or percentage adjustments were used. Conversely, a superior characteristic would require a negative (downward) consideration.

HEARING EXHIBIT - 00000508

LAND VALUE ANALYSIS

Discussion of Sales

SUMMARY OF LAND SALES				
Sale No.	***Subject***	Sale 1	Sale 2	Current Listing 1
ORBk/Page	*N/A*	5596/7877	5781/4010, 5781/4018, 5781/4021, 5781/4026 and 5781/4029	N/A
Grantor	*N/A*	CIDCO Group, LLC	Kabboord Properties, Inc.	Pinner Groves, Inc.
Grantee	*N/A*	Regional Development Group, Inc.	M-2 Industrial, LLC; B and D Industrial, LLC; and Best of Cocoa, LLC	N/A
Location	*7110 N. Courtenay Parkway (SR 3) on the boundary of Kennedy Space Center, on Merritt Island in unincorp Brevard County, FL*	3155 Grissom Parkway, Cocoa, Brevard County, FL	3200 block (south side) of Grissom Parkway, Cocoa, Brevard County, FL	Betw. Smith Road and a barge canal, 1/2 block east of Courtenay Parkway, two-blocks north of SR 528 on Merritt Island in unincorp. Brevard County, FL
Date of Valuation/Sale	*January 17, 2008*	January 26, 2006	May 18, 2007	January 21, 2008
Sale Price	*N/A*	$1,792,200	$1,200,300	$3,750,000
Tax ID No.	*Part of 23-36-13-00-00001.0-0000.00*	24-35-12-00-00753.0-0000.00	24-35-12-00-00760.0-0000.00 and 4 others	24-36-11-00-00500.0-0000.00
Land Use Plan	*None (U.S.-owned land)*	Industrial, by City of Cocoa	Industrial, by City of Cocoa	Industrial, by Brevard County
Zoning	*None (U.S.-owned land)*	M-2, Industrial	M-2, Industrial	PIP, Planned Ind. Park
Shape	*Rectangular*	Rectangular	Rectangular	Rectangular
Utilities	*Water only at property; sanitary sewer is one mile away*	All available including sanitary sewer	All available including sanitary sewer	All available, but requires extending from SR 3
Highest & Best Use	*Light Industrial*	Light-medium Industrial	Light-medium Industrial	Light-medium Industrial
Size (Acres)	*46.00*	15.93	9.68	37.66
Price/Acre of Land	*N/A*	**$112,505**	**$123,998**	**$99,575**
General Comments	*Air Liquide adjoins property on the south which is outside the boundary of the Kennedy Space Center ownership*	Located behind property fronting the north side of Grissom Pkwy, and is now developed with a Fed-Ex complex	A U.S. Forestry facility abuts the property on the east. Since purchase it has been filled to above grade for industrial development	Property is an old citrus grove with 390-feet of restricted frontage on the north side of the barge canal into the bay
QUALITATIVE ANALYSIS (PRICE PER ACRE OF LAND)				
Transaction Status		Closed Sale Similar	Closed Sale Similar	Offer to Sell Very Superior
Market Conditions		Superior	Similar	Similar
General Location		Similar	Similar	Superior
Land Use Plan/Zoning		Superior	Superior	Similar
Size and Shape		Superior	Superior	Similar
Access		Similar	Similar	Similar
Highway Exposure		Inferior	Superior	inferior
Utilities		Superior	Superior	Superior
Overall Comparability		**Very Superior @ $112,505/Acre**	**Very Superior @ $123,998/Acre**	**Very Superior @ $99,575/Acre**

ECRC-08-716
HEARING EXHIBIT - 00000509

LAND VALUE ANALYSIS (Continued)

Discussion of Sales (Continued)

Sale 1 is the January 2006 purchase of 15.93 acres for $1,792,200 ($112,505 per acre) at 3155 Grissom Parkway, in the City of Cocoa, FL. The property is part of a large M-2, medium industrial, zoned area of northern Cocoa, in the northwest quadrant of S.R. 528 and U.S. Highway One. The area is dominated by older industrial activities and warehouses and is the location of a large Rinker Materials cement batch-plant complex, the dominant supplier of cement and concrete block product in Florida. Grissom Parkway parallels S.R. 528 and is the main east-west arterial through the industrial neighborhood. The sale property is located behind small industrial users fronting the north side of the parkway and is accessed by an extended driveway. The land was purchased for and is now developed with a large metal building for Federal Express regional ground delivery operations.

We rate this land sale superior in market conditions, which would require a downward adjustment to the market conditions evident as of the date of the appraised property's valuation. Other factors such as zoning, size and proximity to utility systems (water and sewer) at the time of sale are rated superior. On the other hand, the sale would be rated inferior in highway exposure to the subject property. Overall this sale is rated very superior at $112,505 per acre as an indication of value per acre for the appraised property.

Sale 2 is the May 2007 sale of an aggregate 9.68 acres for $1,200,300 ($123,998 per acre) located along the south side of Grissom Parkway, one-half block west of Sale 1. The land's rear south side backs to the north side of S.R. 528, a limited access highway. This transaction consisted of five adjoining lots all zoned M-2 by the City of Cocoa and purchased individually by the buyer using three different entities from a single seller. The individual tracts range in size from 1.09 to 2.94 acres and the property was purchased with the intent to develop individual buildings. Since purchase, the buyer has filled the land to above the grade of Grissom Parkway in anticipation of further horizontal land infrastructure.

It is recognized that this sale was comprised of five separate lots, each being less than three acres in size, increasing the property future's marketability. That is, the five associated tax parcels involved will allow the buyer to sell each lot individually without further subdivision of the land or additional platting.

We rate this sale similar in market conditions to those evident as of the date of valuation. Other factors such as zoning, size and proximity to utility systems (water and sewer) at sale are rated superior. On the other hand, the sale would be rated superior

EDR-07 HEARING EXHIBIT - 00000510

LAND VALUE ANALYSIS (Continued)

Discussion of Sales (Continued)

because of its additional exposure to S.R. 528 compared to the subject property. Overall this sale is rated very superior at $123,998 per acre as an indication of value per acre for the appraised property.

Current Listing 1 is a 37.66-acre tract offered for sale at $3,750,000 ($99,575 per acre) that has been on the market for more than six months. The property is located 1/2 block east of Courtenay Parkway (SR 3) two blocks north of the northeast corner of the intersection of SR 3 and S.R. 528 on Merritt Island. Comprised of an old citrus grove, the property has 390-feet along the north side of a barge canal that provides boating access between the Indian River along the west side of Merritt Island and the Banana River along the east side of Merritt Island. According to the broker frontage along the barge canal carries no premium due to the U.S. Corps of Engineer's restriction on canal openings into adjacent private property and the canal is of no contribution to industrial users. This listed property is bounded on the north by two-lane Smith Road and on the west by cleared and vacant commercially zoned land fronting Courtenay Parkway.

The property is zoned PIP, Planned Industrial Park, by Brevard County and is being offered as industrially-zoned land. All utilities are available but will have to be extended ½-block from S.R. 3. According to the listing agent, who is well known in Melbourne County and also is a well-qualified state-certified general appraiser, no offers have been made within the last six months. He also anticipates a sale of the property will likely occur at a price substantially lower than the current listed price.

We rate this current listing similar in market conditions to those evident as of the date of valuation, but superior in transaction status being an offer to sell versus a closed market sale. Other factors such as zoning, size and proximity to utility systems (water and sewer) are rated as similar. On the other hand, the listing is rated inferior in highway exposure compared to the subject property, although this is not a significant factor. Overall this listing is rated very superior at $99,575 per acre as an indication of value per acre for the appraised property.

Conclusion

After analysis the data results in the following array of indicated value:

Sale 2 is very superior at	$123,998 per acre
Sale 1 is very superior at	$112,505 per acre
Current Listing 1 is very superior at	$99,575 per acre

SUBJECT

ECR-06-INS HEARING EXHIBIT - 00000511

LAND VALUE ANALYSIS (Continued)

Conclusion (Continued)

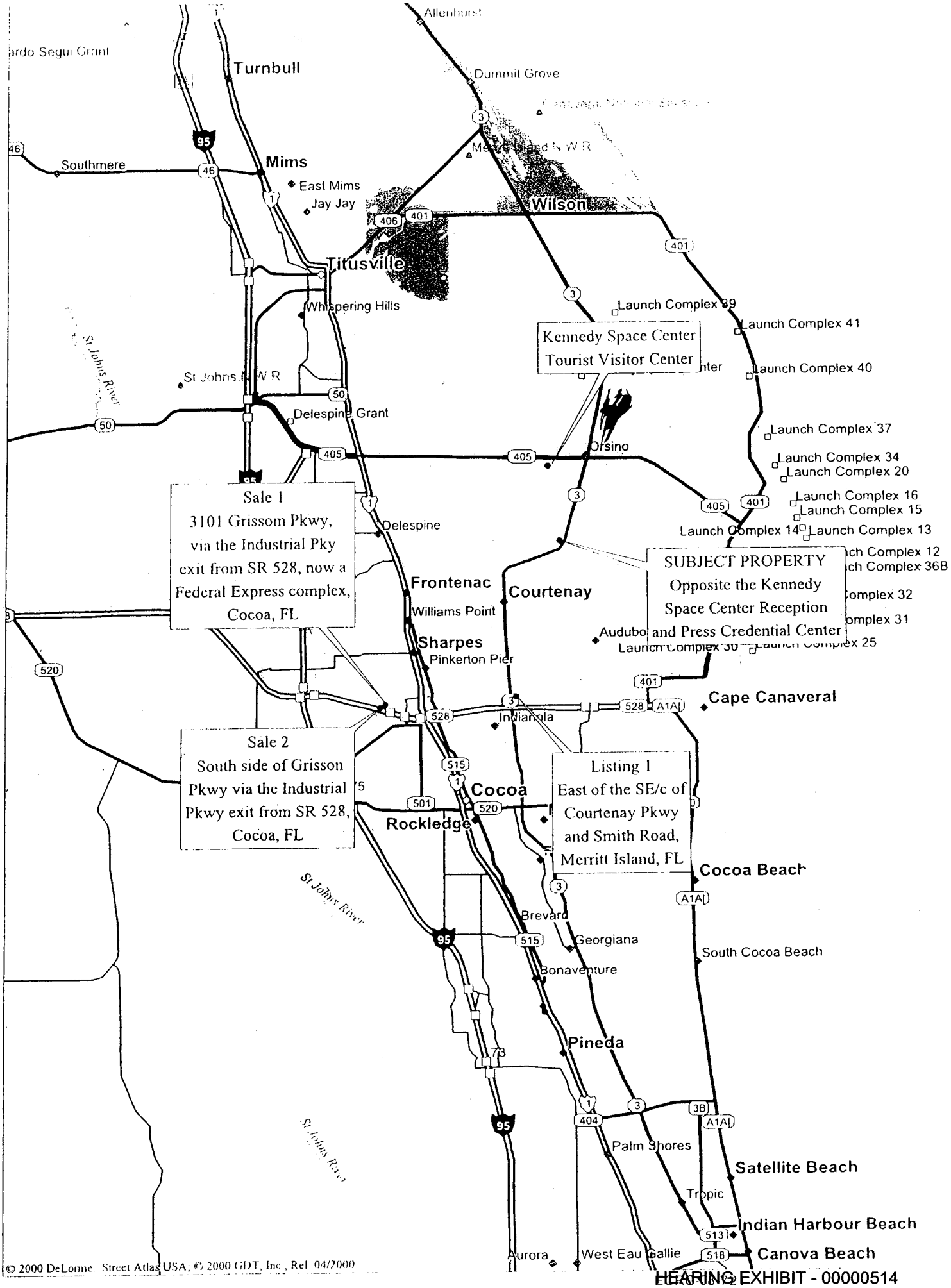
As previously mentioned, during the course of the appraisal discussions were had with numerous participants in Brevard County's industrial real estate market. The price indications from the data utilized do not adequately reflect current market conditions for a 46-acre undeveloped parcel of land presumed to have industrial development potential just inside the large as well as undeveloped and unsecured area of the Kennedy Space Center. All of the data rankings establish superior prices and indicate a conclusion must be below the lowest indication, which is Listing 1. Lengthy discussions with the listing broker were conducted in order to gauge the market. In the final analysis, it is our judgment that the fee simple value of the appraised property is between $75,000 and $85,000 per acre, with the most reasonable estimate of a point value at the low end of this range at $75,000 per acre. Therefore,

46.0 acres x $75,000 per acre =	$3,450,000

EC HEARING EXHIBIT - 00000512

ADDENDA

HEARING EXHIBIT - 00000513



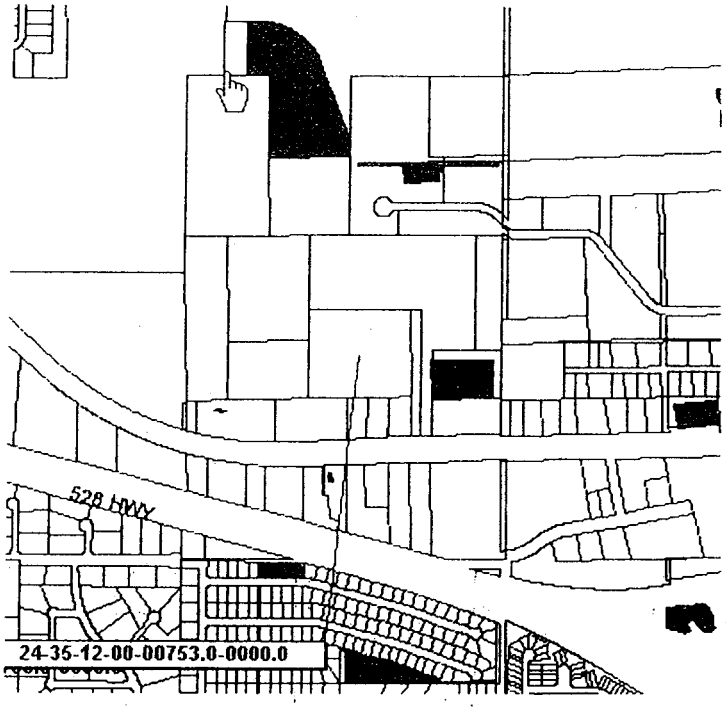
HEARING EXHIBIT - 00000514

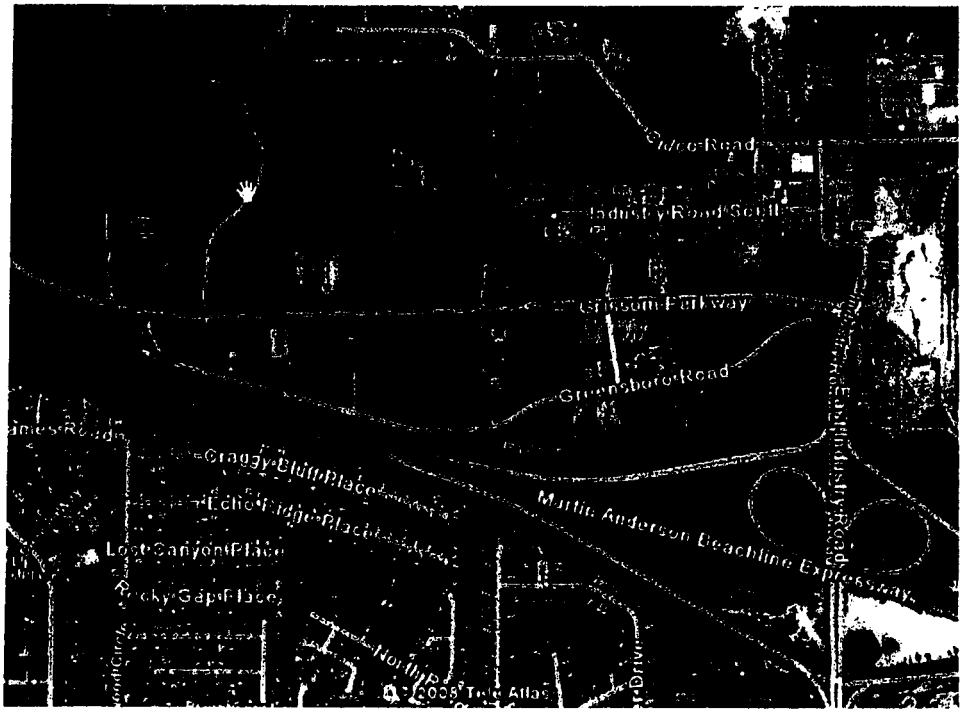
LAND SALE 1

OR Book/Page	Brevard 5596/7877
Date	January 26, 2006
Grantor	CIDCO Group, LLC of Cocoa, FL
Grantee	Regional Development Group, Inc., Orlando, FL
Parcel ID Nos.	24-35-12-00-00753.0-0000.00
Location	3155 Grissom Parkway, City of Cocoa, FL; north and behind property fronting the north side of Grissom Parkway, west of Industrial Boulevard
Legal Description	Abridged: Part of Section 12, T-24-S, R-35-E in Brevard County, Florida
LUP/Zoning	Industrial LUP with M-2 zoning allowing heavy industrial uses, by the City of Cocoa, FL
Land Size	15.93 acres
Shape/Topography	Rectangular shaped, level tract of land accessed by an extended driveway from Grissom Parkway. Not included was the buyer's post-sale requirement to construct the paved roadway into the property from Grissom Parkway.
Utilities	All municipal utilities and services were available at sale including city water and sanitary sewer
Improvements at Sale	None at sale. Property is now developed with a Federal Express ground delivery operations facility.
Sale Price	$1,792,200
Price per Acre	$112,505
Financing	All cash sale, with no mortgage of record
Verification	Public records and Stan Jones, principal of the buyer (407-855-0310)

EDHEARING EXHIBIT - 00000515

LAND SALE 1 (Continued)





EORE-08723 HEARING EXHIBIT - 00000516

LAND SALE 2

OR Book/Page	Brevard County 5781/4010, 4018, 4021, 4026 and 4029
Date	May 18, 2007
Grantor	Kabboord Properties Inc., Cocoa Beach, FL
Grantee	M-2 Industrial LLC; B and D Industrial LLC; and Best of Cocoa LLC
Parcel ID Nos.	24-35-12-00-00760.0-0000.00, and 4 others
Location	South side of the 3200 block of Grissom Parkway, Cocoa, FL
Legal Description	Abridged: Part of Section 12, T-24-S, R-35-E, in Brevard County, FL
LUP/Zoning	Industrial LUP with M-2 zoning allowing heavy industrial uses, by the City of Cocoa, FL
Land Area	9.68 acres
Shape/Topography	Rectangular shaped tract fronting the south side of Grissom Parkway, with the rear south side backing to the north side of S.R. 528, a limited access highway
Utilities	All municipal utilities and services were available at sale including city water and sanitary sewer
Improvements at Sale	A few small older buildings that contributed no value to the property, and which have since been demolished
Sale Price	$1,200,300
Price per Acre	$123,998
Financing	All cash sale to the seller
Comments	This sale consisted of five adjoining tax parcels with individual deeds and prices established for each parcel, aggregating to the total land size and purchase price

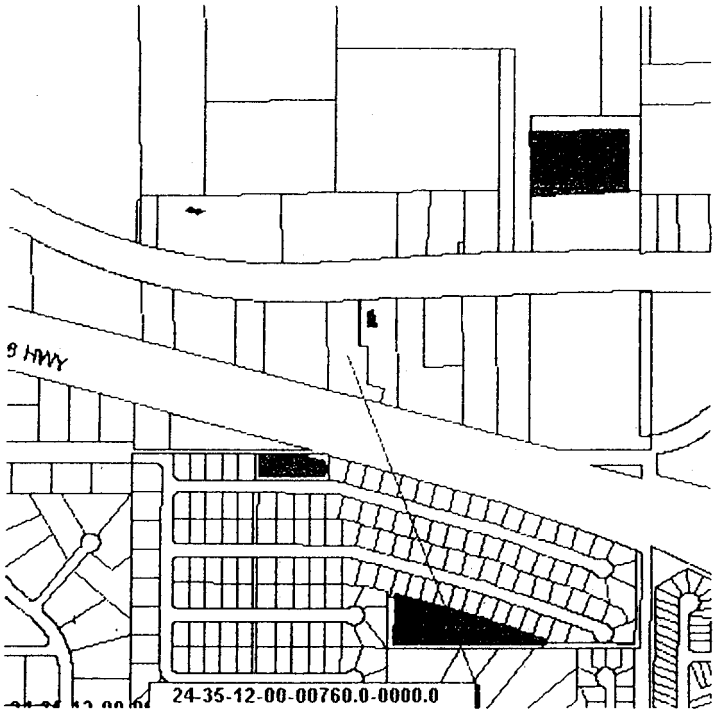
EC HEARING EXHIBIT - 00000517

LAND SALE 2 (Continued)

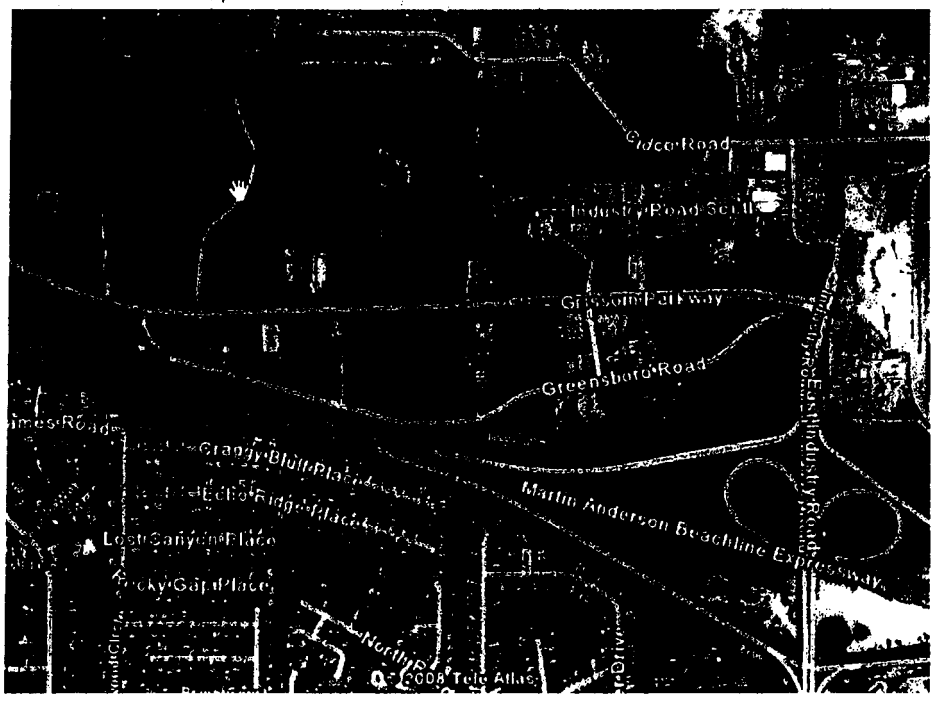
	shown. The property has since been filled to above the grade of Grissom Parkway and leveled in anticipation of the buyer developing seven 160' x 311' lots for individual buildings.
Verification	Don Blauvelt (S.F. Holden, Inc.) with David Kabboord, the seller (321-783-1234)

HEARING EXHIBIT - 00000518

LAND SALE 2 (Continued)



(eastern parcel of five contiguous parcels of this sale)



EOR0 00776
HEARING EXHIBIT - 00000519

CURRENT LISTING 1

OR Book/Page	Not Applicable
Date	As of January 24, 2008
Grantor	Pinner Groves, Inc.
Grantee	Not Applicable
Parcel ID No.	24-36-11-00-00500.00-0000.00
Location	½ block east of Courtenay Parkway (S.R. 3) on the south side of Smith Road, Merritt Island, FL
Legal Description	Abridged: Part of Section 11, T-24-S, R-23-E in Brevard County, Florida
LUP/Zoning	PI, Planned Industrial, LUP and PIP, Planned Industrial Park, zoning
Land Area	37.66 acres
Shape/Topography	Rectangular shaped parcel of level land
Utilities Available	All municipal services and utilities are available but must be extended from Courtenay Parkway
Current Improvements	Old citrus grove facilities of no value to the highest and best zoned use of the property
Listed Price	$3,750,000
Listed Price per Acre	$99,575
Financing	Sale requires all cash to the seller
Comments	Property backs to and has 390 feet along the north side of the barge canal that runs just north and parallel to SR 528 providing boat access between the Indian River to the west and the Banana River bay to the east. Due to U.S. Army Corps of Engineers regulations, no canal bank opening into abutting private property is permitted.

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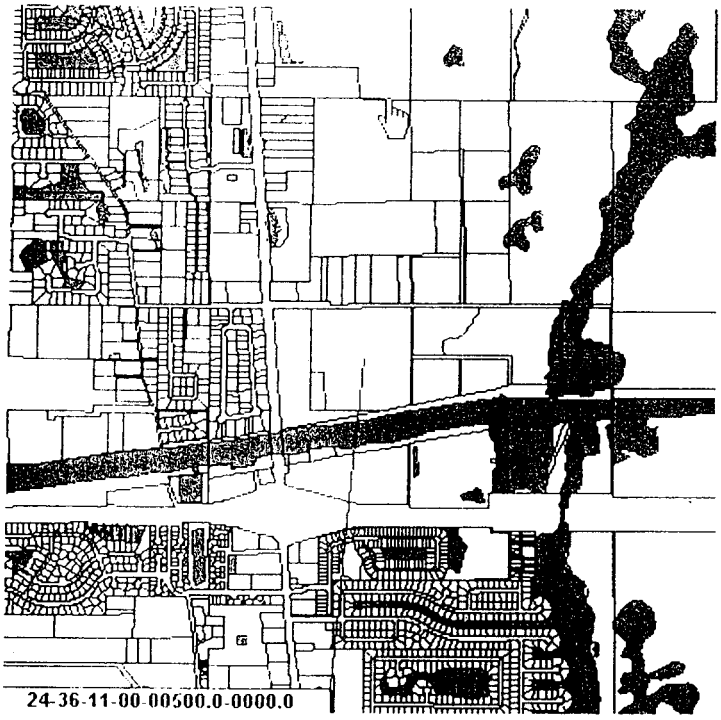
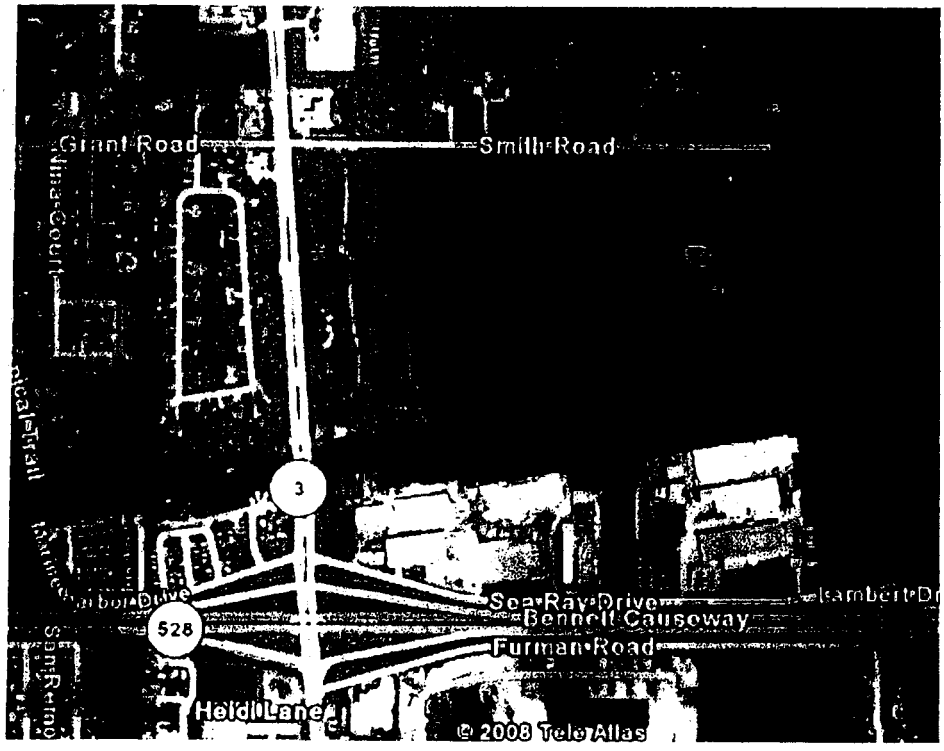
CURRENT LISTING 1 (Continued)

Comments (Continued)	According to the listing agent, no serious offer has been made for purchase of the property in the past six months and the expectation is that a sale will not occur unless a significant reduction is made to the current asking price.
Verification	Don Blauvelt (S.F. Holden, Inc.) with Dennis Basile of Pruitt Real Estate, Inc. (321-427-9560)

ECR HEARING EXHIBIT - 00000521

CURRENT LISTING 1 (Continued)





ECR-09-700 HEARING EXHIBIT - 00000522

1988 Comprehensive Plan
Industrial Zoning Categories

EC HEARING EXHIBIT - 00000523

1988 Comprehensive Plan.
Industrial Zoning Categories. p. 95

(6) Tourist commercial and transient commercial zoning classifications:

a. General tourist commercial zoning classification, TU-1.

b. Transient tourist commercial zoning classification, TU-2.

(7) Industrial zoning classifications:

a. Planned business park zoning classification, PBP.

b. Planned industrial park zoning classification, PIP.

c. Light industrial zoning classification, IU.

d. Heavy industrial zoning classification, IU-1.

(8) Special zoning classifications:

a. Environmental area zoning classification, EA.

b. Government managed land zoning classification, GML.

c. Institutional zoning classification, IN.

(b) *Consistency of zoning classifications with comprehensive plan.* The 1988 county comprehensive plan establishes specific future land use designations, which are depicted on the future land use map within the future land use element. The future land use element also has policies and criteria which delineate how the various designations shall be applied. The zoning classifications depicted on the official zoning map of the county shall be consistent with the future land use map and the policies and criteria relating to the application of future land use designations on the future land use map.

(1) *Future land use designations.*

a. *Residential.* Residential uses include single-family detached, single-family attached, multiple-family, recreational vehicle park and mobile home developments.

1. Residential 30:

A. Maximum, unless otherwise provide herein: 30 units per acre.

B. Merritt Island redevelopment area: Development containing a mixture of uses: 50 units per acre per policy 1.3(B)(2) of the Future Land Use Element.

C. Redevelopment district: 37.5 units per acre per policies 1.3(B)(1) and

1988 Comprehensive Plan,
PBP, PIP & IU Industrial Zoning, pp. 227-238.

(8) *Structural height standards.*

a. Where the property abuts any other land located in the GU, AGR, AU, ARR, REU, RU-1-7, RU-1-9, RU-1-11, RU-1-13, RR-1, EU, EU-1, EU-2, SEU, SR, RVP, TR-1-A, TR-1, TR-2, TR-3, TRC-1, RRMH-1, RRMH-2.5, RRMH-5, EA, PA or GML zoning classification, the maximum height threshold of any structure or building thereon shall be 35 feet.

b. Where the property abuts any other land located in the RA-2-4, RA-2-6, RA-2-8, RA-2-10, RU-2-4, RU-2-6, RU-2-8, RU-2-10, RU-2-12, RP or BU-1-A zoning classification, the maximum height threshold of any structure or building thereon shall be 45 feet.

c. Where the property abuts any other land located in the RU-2-15, RU-2-30, BU-1, BU-2, PBP IU, IU-1, TU-1 or TU-2 zoning classification, the maximum height threshold of any structure or building thereon shall be 60 feet.

d. Where any structure or building exceeds 35 feet in height, all conditions enumerated in section 62-2101.5 as applicable shall be fully satisfied.

e. Structures or buildings may not exceed the maximum height thresholds stated in this subsection unless otherwise permitted by section 62-2101.5.

(9) *Site plan.* A site plan shall be submitted in accordance with article VIII of this chapter.

(10) *Metal buildings.* Metal buildings shall be permitted in this zoning classification subject to the restrictions presented in section 62-2115.

(11) *Maximum floor area ratio.* The floor area ratio shall be governed by section 62-2110.

(Code 1979, § 14-20.13(B); Ord. No. 95-47, §§ 58, 59, 10-19-95; Ord. No. 95-49, §§ 13, 18, 10-19-95; Ord. No. 96-16, §§ 61, 62, 3-28-96; Ord. No. 97-40, § 5, 10-14-97; Ord. No. 98-12, § 12, 2-26-98; Ord. No. 99-07, § 12, 1-28-99; Ord. No. 01-30, § 13, 5-24-01; Ord. No. 2002-42, § 7, 8-27-02; Ord. No. 04-29, § 29, 8-5-04; Ord. No. 2004-52, § 26, 12-4-04; Ord. No. 05-27, § 3, 5-19-05)

Secs. 62-1513--62-1539. Reserved.

Subdivision VIII.

Industrial

Sec. 62-1540. Industrial uses permitted with conditions and conditional uses.

Industrial Uses "Permitted with Conditions" or "Requiring a Conditional Use Permit (CUP)*"

Use	BU-1 & BU-2	PBP	PIP	IU	IU-1
Contractors	Pc	Pc	Pc	Pc	Pc
Heavy Industry					C
Industry	C	Pc	Pc	Pc	Pc

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Office and Research	Pc	Pc	Pc	Pc	Pc
Transportation				Pc	Pc
Trucking			C	Pc	Pc
Waste Disposal					C
Pc = Permitted with conditions (See sections 62-2251 through 62-2271)					
C = Conditional Use (see section 62-1901).					
* Additional Pc and CUP uses are listed in sections 62-1541, 1542, 1543 and 1544.					

(Ord. No. 2000-07, § 2, 1-25-00; Ord. No. 2000-50, § 5, 10-31-00)

Sec. 62-1541. Planned business park, PBP.

The PBP planned business park zoning classification is intended to encourage compatible development within areas designated community commercial and planned industrial on the future land use map of the county comprehensive plan. The intent of the regulations for this classification is to provide the opportunity for the aggregation of land, prevent piecemeal nonresidential development and protect environmentally and historically significant areas. The SR 405/SR 407 corridor shall apply to property fronting that area of SR 405 running from Barna Avenue to the Indian River Lagoon and that area of SR 407 running from I-95 to SR 405.

(1) *Permitted uses.*

a. Permitted uses are as follows:

All uses permitted in the BU-1 and BU-2 classification.

Hotels and motels, limited to 30 units per acre.

b. Permitted uses with conditions are as follows (see division 5, subdivision II, of this article):

Uses "permitted with conditions" will be controlled by section 62-1540 and performance standards.

Preexisting use.

Single family residence.

(2) *Accessory uses.* The following uses shall be permitted if primarily intended for the use of employees and visitors, as long as they are located entirely within the principal building:

Branch banks, credit unions and post offices.

Cafeterias or snack bars.

Exhibition halls specifically related to the principal use of the property.

Retail sales, limited to the sale of sundries, stationery, office supplies and similar goods and the sale of products and materials manufactured on the premises, which shall not exceed five percent of the gross floor area.

(3) *Conditional uses.* Conditional uses are as follows:

Change of nonconforming agricultural use.

Land alteration (over five acres).

Marinas, commercial or recreational.

Substantial expansion of a preexisting use.

Towers and antennas.

(4) *Lot, site and building requirements.*

a. *Generally.*

1. Minimum park size is five acres.

2. Minimum lot size is one-half acre.

3. Minimum building size is 2,500 square feet.

4. Maximum structural coverage is 50 percent of the lot.

5. Minimum common open space is 20 percent of the site.

b. *SR 405/SR 407 corridor.*

1. Minimum lot size is three acres.

2. Minimum lot width is 300 feet.

3. Minimum lot depth is 400 feet.

4. Minimum building size is 10,000 square feet.

5. Maximum structural coverage is 50 percent of the lot.

6. Minimum common open space is 20 percent of the site.

(5) *Setbacks.*

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a. *Generally.*

1. The front setback shall be 25 feet from an internal access road or 50 feet from any public right-of-way.

2. The side setback shall be 50 feet, or zero feet where a marginal access road is provided or where a single access is utilized by more than one lot from an internal road and parking facilities are shared.

3. The rear setback shall be 25 feet, or 40 feet if the rear lot line is the site periphery, or zero feet if the rear lot line abuts a railroad right-of-way.

4. On property adjacent to a river or lagoon, a minimum of 30 percent of the river frontage shall be left open as breezeway/visual corridor.

b. *SR 405/SR 407 corridor.*

1. The front setback shall be 100 feet from an internal access road, or 200 feet from SR 405 or SR 407.

2. The side setback shall be 50 feet. A 100-foot side street setback is required where the lot is a corner lot.

3. The rear setback shall be 100 feet.

(6) *Structural height standards.*

a. Where the property abuts any other land located in the GU, AGR, AU, ARR, REU, RU-1-7, RU-1-9, RU-1-11, RU-1-13, RR-1, EU, EU-1, EU-2, SEU, SR, RVP, TR-1-A, TR-1, TR-2, TR-3, TRC-1, RRMH-1, RRMH-2.5, RRMH-5, EA, PA or GML zoning classification, the maximum height threshold of any structure or building thereon shall be 35 feet.

b. Where the property abuts any other land located in the RA-2-4, RA-2-6, RA-2-8, RA-2-10, RU-2-4, RU-2-6, RU-2-8, RU-2-10, RU-2-12, RU-2-15, RU-2-30, RP, BU-1-A, BU-1, BU-2, TU-1, TU-2, PBP, PIP, IU or IU-1 zoning classification, the maximum height threshold of any structure or building thereon shall be 45 feet.

c. Where any structure or building exceeds 35 feet in height, all conditions enumerated in section 62-2101.5 as applicable shall be fully satisfied.

d. Structures or buildings may not exceed the maximum height thresholds stated in this subsection unless otherwise permitted by section 62-2101.5.

(7) *Parking and loading.*

a. Loading facilities and truck parking. Loading docks are prohibited on an interior street frontage. They shall be located to the rear of the front building line, paved, and have adequate drainage. Parking for trucks and other commercial vehicles and heavy equipment shall be located at the rear of all principal structures. No shipping or receiving shall be permitted within 75 feet of residentially zoned property.

(8) *Lighting and utilities.*

a. Shaded light sources shall be used to illuminate signs, facades, buildings, and parking and loading areas, shall be arranged to eliminate glare onto roadways and streets, and shall be directed away from properties lying outside the district.

b. Shaded light sources are lighting elements shielded with an opaque shade to direct the light.

c. No neon lights, intermittent lights or flashing lights shall be allowed.

(9) *Metal buildings.* Metal buildings shall be permitted subject to the restrictions of section 62-2115.

(10) *Maximum floor area ratio.* The floor area ratio shall be governed by section 62-2110.

(Code 1979, § 14-20.14(A); Ord. No. 95-47, §§ 60, 61, 10-19-95; Ord. No. 95-49, § 18, 10-19-95; Ord. No. 96-16, §§ 63, 64, 3-28-96; Ord. No. 97-48, § 1, 12-9-97; Ord. No. 98-12, § 13, 2-26-98; Ord. No. 99-07, § 12, 1-28-99; Ord. No. 2000-07, § 3, 1-25-00; Ord. No. 01-30, § 14, 5-24-01; Ord. No. 2002-01, § 6, 1-8-02; Ord. No. 2002-42, § 8, 8-27-02; Ord. No. 04-43, § 1, 10-19-04; Ord. No. 2004-52, § 27, 12-4-04)

State Law References: Planned unit developments encouraged, F.S. § 163.3202(3).

Sec. 62-1542. Planned industrial park, PIP.

The PIP planned industrial park zoning classification is intended for locations which are served by major roads but are not feasible for light or heavy industrial developments because of proximity to residential uses. The regulations for this district are intended to encourage development compatible with surrounding or abutting residential districts, with suitable open spaces, landscaping and parking areas. Consequently, manufacturing activities that can be carried on in a relatively unobtrusive manner, and certain facilities that are necessary to serve the employees of the district, are permitted. All property in this zoning classification shall have a structure located on the property with a minimum of 300 square feet prior to utilizing the property for any of the uses permitted in this section.

(1) *Permitted uses.*

a. The following uses are permitted providing they are in compliance with the performance standards set forth in division 6, subdivision III, of this article and providing they take place within substantial buildings completely enclosed with walls and a roof.

All uses permitted in the BU-1 and BU-2 classification.

Motels.

b. Permitted uses with conditions are as follows (see division 5, subdivision II, of this article):

Uses "permitted with conditions" will be controlled by section 62-1540 and performance standards.

Boatbuilding facility.

Preexisting use.

Recovered materials processing facility.

Single family residence.

(2) *Accessory uses.*

a. Customary accessory uses are permitted, including operations required to maintain or support any use permitted in this zone on the same lot as the permitted use, such as maintenance shops, and machine shops, provided these take place within enclosed buildings.

b. The following uses are permitted as a convenience to the occupants thereof and their customers and employees:

Convention or exhibit hall.

Dining facilities.

Recreational facilities.

(3) *Conditional uses.* Conditional uses are as follows:

Change of nonconforming agricultural use.

Commercial/industrial marina.

Land alteration (over five acres).

Substantial expansion of a preexisting use.

Towers and antennas.

(4) *Minimum size and lot size.* The minimum lot size shall be one acre, having a minimum width of 150 feet and a minimum depth of 200 feet. The minimum size of a planned industrial site as designated on the future land use map shall be three acres.

(5) *Setbacks.*

a. *Front yard.* All buildings shall be set back from all street right-of-way lines at least 50 feet.

b. *Side yard.* No building or wall shall be located closer than 50 feet to a side yard lot line.

c. *Rear yard.* No structures or truck parking and loading shall be located closer than 25 feet to the rear lot line. No rear yard is required where the lot abuts on an existing or proposed railroad right-of-way or spur.

(6) *Maximum lot coverage.* Structural coverage, including storage areas, shall not exceed 50 percent of the area of the lot.

(7) *Structural height standards.*

a. Where the property abuts any other land located in the GU, AGR, AU, ARR, REU, RU-1-7, RU-1-9, RU-1-11, RU-1-13, RR-1, EU, EU-1, EU-2, SEU, SR, RVP, TR-1-A, TR-1, TR-2, TR-3, TRC-1, RRMH-1, RRMH-2.5, RRMH-5, EA, PA or GML zoning classification, the maximum height threshold of any structure or building thereon shall be 35 feet.

b. Where the property abuts any other land located in the RA-2-4, RA-2-6, RA-2-8, RA-2-10, RU-2-4, RU-2-6, RU-2-8, RU-2-10, RU-2-12, RU-2-15, RU-2-30, RP, BU-1-A, BU-1, BU-2, PBP, PIP, IU, IU-1, TU-1 or TU-2 zoning classification, the maximum height threshold of any structure or building thereon shall be 45 feet.

c. Where any structure or building exceeds 35 feet in height, all conditions enumerated in section 62-2101.5 as applicable shall be fully satisfied.

d. Structures or buildings may not exceed the maximum height thresholds stated in this subsection unless otherwise permitted by section 62-2101.5.

(8) *Other requirements.*

a. *Loading facilities and truck parking.*

1. Loading docks are prohibited on an interior street frontage. They shall be located to the rear of the front building line of all principal structures, paved, and have adequate drainage.

2. Parking for trucks and other commercial vehicles and heavy equipment shall be located at the rear of all principal structures.

3. No shipping or receiving shall be permitted within 75 feet of residentially zoned

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property.

b. *Storage.* All storage areas shall be located to the rear of the primary structures. All outside storage areas shall be enclosed by a visual barrier when viewed from the public road right-of-way or adjacent lots not industrially zoned. Such enclosure shall be a minimum of six feet and a maximum of eight feet in height, and in no case shall materials be stacked or stored so as to exceed the height of the enclosure. The enclosure shall be either a masonry wall, opaque fence, landscaped berm or other materials adequate to create a permanent opaque barrier. The storage area's entrance and exit gates shall also be opaque when materials within it are visible from any public road right-of-way or adjacent lots not industrially zoned. Storage areas must be located at least 75 feet from any street right-of-way lines. No motor vehicle which is inoperable or trailer which is unusable shall be stored or used for storage on any lot or parcel of ground in this zone unless it is within a completely enclosed building.

c. *Lighting and utilities.*

1. Shaded light sources shall be used to illuminate signs, facades, buildings, and parking and loading areas, shall be so arranged as to eliminate glare from roadways and streets, and shall be directed away from properties lying outside the district.

2. Shaded light sources are lighting elements shielded with an opaque shade to direct the light.

3. No neon lights, intermittent lights or flashing lights or such lighted signs shall be allowed.

d. *Riverfront property.* On property bordering a river, a minimum of 30 percent of the river frontage shall be left open as breezeway/visual corridor.

(Code 1979, § 14-20.14(B); Ord. No. 95-46, §§ 1, 2, 10-19-95; Ord. No. 95-47, §§ 62, 63, 10-19-95; Ord. No. 95-49, §§ 8, 18, 10-19-95; Ord. No. 96-16, §§ 65, 66, 3-28-96; Ord. No. 97-48, § 2, 12-9-97; Ord. No. 98-11, § 5, 2-26-98; Ord. No. 98-12, § 14, 2-26-98; Ord. No. 98-13, § 1, 2-26-98; Ord. No. 99-07, § 12, 1-28-99; Ord. No. 2000-07, § 4, 1-25-00; Ord. No. 01-30, § 15, 5-24-01; Ord. No. 2002-42, § 9, 8-27-02; Ord. No. 04-43, § 1, 10-19-04)

State Law References: Planned unit developments encouraged, F.S. § 163.3202(3).

Sec. 62-1543. Light industrial, IU.

The IU light industrial zoning classification is established to provide areas in which the principal use of land is for manufacturing, assembling and fabrication, and for warehousing. These uses do not depend primarily on frequent personal visits of customers or clients, but usually require good accessibility to major rail, air or street transportation routes. All property in this zoning classification shall have a structure located on the property with a minimum of 300 square feet prior to utilizing the property for any of the uses permitted in this section.

(1) *Permitted uses.*

a. The following uses and structures are permitted provided they comply with the performance standards set forth in division 6, subdivision III, of this article and take place within an enclosed building:

All uses permitted in the BU-1 and BU-2 classification, except, single-family residence.

b. Permitted uses with conditions are as follows (see division 5, subdivision II, of this article):

Uses "permitted with conditions" will be controlled by section 62-1540 and performance standards.

Assisted living facility.

Commercial entertainment and amusement enterprises (small scale).

Power substations and transmission facilities.

Preexisting use.

Recovered materials processing facility.

Treatment and recovery facility.

(2) *Accessory uses.*

a. Customary accessory buildings and uses are permitted, including operations required to maintain or support any use permitted in this zone on the same lot as the permitted use, such as maintenance shops and machine shops.

b. The following uses are permitted as a convenience to the occupants thereof and their customers and employees:

Convention or exhibition hall.

Dining facilities.

Laundry.

Recreational facilities.

c. Roadside stands used for the sale of agricultural produce as provided in chapter 86, article IV, are permitted as an accessory use.

d. Security trailers are permitted as an accessory use.

(3) *Conditional uses.* Conditional uses are as follows:

Alcoholic beverages for on-premises consumption.

Change of nonconforming agricultural use.

Commercial entertainment and amusement enterprises (large scale).

Commercial/recreational and commercial/industrial marina.

Composting facility.

Flea markets (recreational vehicles).

Land alteration (over five acres).

Motocross.

Mulching facility.

Substantial expansion of a preexisting use.

Towers and antennas.

Truss manufacturing plant.

(4) *Minimum lot size.* Individual building sites shall be of such size that space requirements provided in this chapter are complied with. All lots shall have a minimum size of 20,000 square feet, and have a minimum width of 100 feet and a minimum depth of 200 feet.

(5) *Setbacks.*

a. *Front yard.* Structures shall be set back not less than 40 feet from the front property line.

b. *Side yard.* No building or wall shall be located closer than 15 feet to a side yard lot line. The width of a side yard which abuts a residential district shall be at least 100 feet, 20 feet of which shall be a buffer zone.

c. *Rear yard.* No structures or truck parking and loading shall be located closer than 25 feet to the rear lot line. Where the lot abuts a residential district, no structures shall be permitted closer than 100 feet to the rear lot line. However, no rear yard is required where the lot abuts on an existing or proposed railroad right-of-way or spur. Truck parking and loading facility setbacks is addressed in subsection (8)a. of this section.

(6) *Maximum lot coverage.* Building coverage, including storage areas, shall not exceed 50 percent

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of the area of the lot.

(7) *Structural height standards.*

a. Where the property abuts any other land located in the GU, AGR, AU, ARR, REU, RU-1-7, RU-1-9, RU-1-11, RU-1-13, RR-1, EU, EU-1, EU-2, SEU, SR, RVP, TR-1-A, TR-1, TR-2, TR-3, TRC-1, RRMH-1, RRMH-2.5, RRMH-5, EA, PA or GML zoning classification, the maximum height threshold of any structure or building thereon shall be 35 feet.

b. Where the property abuts any other land located in the RA-2-4, RA-2-6, RA-2-8, RA-2-10, RU-2-4, RU-2-6, RU-2-8, RU-2-10, RU-2-12, RP or BU-1-A zoning classification, the maximum height threshold of any structure or building thereon shall be 45 feet.

c. Where the property abuts any other land located in the RU-2-15, RU-2-30, BU-1, BU-2, PBP, PIP, IU, IU-1, TU-1 or TU-2 zoning classification, the maximum height threshold of any structure or building thereon shall be 60 feet.

d. Where any structure or building exceeds 35 feet in height, all conditions enumerated in section 62-2101.5 as applicable shall be fully satisfied.

e. Structures or buildings may not exceed the maximum height thresholds stated in this subsection unless otherwise permitted by section 62-2101.5.

(8) *Other requirements.*

a. *Loading facilities and truck parking.* No shipping or receiving of goods shall be permitted within 100 feet of residentially zoned property. Where the lot abuts a commercial district, no truck parking and loading shall be permitted closer than 50 feet to the rear lot line. However, no rear yard is required where the lot abuts an existing or proposed railroad right-of-way or spur.

b. *Storage.* All storage areas shall be located to the rear of the primary structures. All open areas for storage shall be enclosed by a visual barrier when viewed from the public road right-of-way or adjacent lots not industrially zoned. Such enclosure shall be a minimum of six feet and a maximum of eight feet in height, and in no case shall materials be stacked or stored so as to exceed the height of the enclosure. The enclosure shall be either a masonry wall, opaque fence, landscaped berm or other materials adequate to create a permanent opaque barrier. The storage area's entrance and exit gates shall also be opaque when materials within it are visible from any public road right-of-way or adjacent lots not industrially zoned. Storage areas must be located at least 25 feet from any side or rear lot line. No motor vehicle which is inoperable or trailer which is unusable shall be stored or used for storage on any lot or parcel of ground in this zone unless it is within a completely enclosed building.

c. *Fencing.* When any property used for the uses permitted in this zoning classification is

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contiguous to or abuts property zoned other than BU-1, BU-2, PBP, PIP, IU or IU-1, a six-foot fence shall be constructed on the contiguous property line and may be constructed within the front setback area, provided that the fence is not opaque, notwithstanding the requirements of section 62-2109.

d. *Lighting and utilities.*

1. Shaded light sources shall be used to illuminate signs, facades, buildings, and parking and loading areas, shall be so arranged as to eliminate glare from roadways and streets, and shall be directed away from properties lying outside the district.

2. Shaded light sources are lighting elements shielded with an opaque shade to direct the light.

3. No neon lights, intermittent lights or flashing lights or such lighted signs shall be allowed.

e. *Performance standards.* All permitted uses within this zone shall be subject to the performance standards outlined in division 6, subdivision III, of this article.

f. *Riverfront property.* On property bordering a river, a minimum of 30 percent of the river frontage shall be left open as breezeway/visual corridor.

(9) *Maximum floor area ratio.* The maximum floor area ratio shall be 2.48.

(Code 1979, § 14-20.14(C); Ord. No. 95-17, § 2, 4-11-95; Ord. No. 95-46, §§ 3, 4, 10-19-95; Ord. No. 95-47, §§ 64, 65, 10-19-95; Ord. No. 95-49, § 18, 95; Ord. No. 96-16, §§ 67, 68, 3-28-96; Ord. No. 96-35, § 1, 7-23-96; Ord. No. 97-48, § 3, 12-9-97; Ord. No. 98-12, § 15, 2-26-98; Ord. No. 98-11, § 6, 2-26-98; Ord. No. 99-07, §§ 12, 21, 1-28-99; Ord. No. 99-45, § 2, 8-12-99; Ord. No. 2000-07, § 5, 1-25-00; Ord. No. 01-07, § 7, 2-20-01; Ord. No. 01-30, § 16, 5-24-01; Ord. No. 2002-42, § 10, 8-27-02; Ord. No. 04-29, § 30, 8-5-04; Ord. No. 2004-52, § 28, 12-4-04)

Sec. 62-1544. Heavy industrial, IU-1.

The IU-1 heavy industrial district is established to provide areas in which the principal use of land is primarily for manufacturing and other heavy uses. However, the application of performance and design standards should minimize many of the adverse effects of these heavy industrial uses. Property in this zoning classification shall have a structure located on the property with a minimum of 300 square feet prior to utilizing the property for any of the uses permitted in this section.

(1) *Permitted uses.*

a. The following uses are permitted, provided that they comply with the performance standards set forth in division 6, subdivision III, of this article:

All uses permitted in the BU-1, BU-2 and IU classifications, except, single-family

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1988 Comprehensive Plan.
BU-1 and BU-2 Zoning, pp. 203-221

(Code 1979, § 14-20.12(A); Ord. No. 93-19, § 1, 6-22-93; Ord. No. 95-47, §§ 50, 51, 10-19-95; Ord. No. 95-49, § 4, 10-19-95; Ord. No. 96-16, §§ 53, 54, 3-28-96; Ord. No. 97-23, § 1, 7-8-97; Ord. No. 97-40, § 1, 10-14-97; Ord. No. 99-07, § 12, 1-28-99; Ord. No. 01-07, § 1, 2-20-01; Ord. No. 01-30, § 9, 5-24-01; Ord. No. 2001-71, § 3, 11-1-01; Ord. No. 2002-42, § 3, 8-27-02; Ord. No. 2002-43, § 1, 8-27-02; Ord. No. 2002-49, § 32, 9-17-02; Ord. No. 2003-03, § 26, 1-14-03; Ord. No. 04-29, § 25, 8-5-04; Ord. No. 2004-52, § 22, 12-4-04; Ord. No. 05-27, § 3, 5-19-05; Ord. No. 05-40, § 6, 8-23-05; Ord. No. 06-54, § 1, 10-5-06; **Ordinance No. 2007-052, enacted October 4, 2007; Ordinance No. 2007-059, enacted December 6, 2007.)**

Sec. 62-1482. General retail commercial, BU-1.

The BU-1 general retail commercial zoning classification encompasses land devoted to general retail shopping, offices and personal services to serve the needs of the community. Where this zoning classification is presently located or is proposed to be located adjacent to the lagoonal water edge or fronts on the ocean, water-dependent uses such as fish, shellfish and wildlife production, recreation, water-dependent industry and utilities, marinas and navigation shall have the highest priority. The next highest priority for uses along the waterfront include water-related uses such as utilities, commerce and industrial uses. Water-enhanced uses such as restaurants and tourist attractions shall have the next highest use priorities. Of lowest priority are those uses which are nonwater-dependent and nonwater-enhanced, and those which result in an irretrievable commitment of coastal resources.

(1) *Permitted uses.*

a. All business uses and all material and products shall be confined within substantial buildings completely enclosed with walls and a roof; however, retail items of substantial size or which of necessity must remain outside of a building may be permitted to be displayed outside the buildings. Such retail items include but are not limited to motor vehicles, utility sheds, nursery items such as plants and trees, and boats.

b. The following uses, or other uses of a similar nature compatible with the character of the uses specifically described in this subsection, are permitted, and shall be limited to retail only:

Administrative, executive and editorial offices.

Antique shops.

Aquariums.

Art goods and bric-a-brac shops.

Artists' studios.

Auditoriums.

Automobile hire.

Automobile parts, if confined within a structure.

Automobile repairs, minor (as defined in Section 62-1102).

Automobile sales and storage, provided sales are from a permanent structure and the storage area meets the requirements of article VIII of this chapter, pertaining to site plans, and article XIII, division 2, of this chapter, pertaining to landscaping.

Automobile tires and mufflers (new), sales and service.

Automobile washing.

Bait and tackle shop.

Bakery sales, with baking permitted on the premises.

Banks and financial institutions.

Barbershops and beauty parlors.

Bed and breakfast inn.

Bicycle sales and service.

Billiard rooms and electronic game arcades (soundproofed).

Bookstores.

Bowling alleys (soundproofed).

Cafeterias.

Ceramics and pottery; finishing and sales; no production or firing except accessory to on site sales only.

Civic, philanthropic or fraternal organizations.

Coin laundromats.

Colleges and universities.

Commercial schools offering instruction in dramatic, musical or other cultural activity, including martial arts.

Confectionery and ice cream stores.

Conservatories.

Contractors' offices, with no outside storage.

Convenience stores, with or without gasoline sales.

Curio shops.

Dancing halls and academies (soundproofed).

Child or adult day care centers.

Display and sales rooms.

Dog and pet hospitals and beauty parlors, with no outside kennels or runs.

Drug and sundry stores.

Dyeing and carpet cleaning.

Electrical appliance and lighting fixtures.

Employment agencies.

Fraternities and sororities.

Florist shops.

Foster homes.

Fruit stores (packing on premises).

Funeral homes and mortuaries.

Furniture stores.

Furriers.

Gift shops.

Grocery stores.

Group homes, levels I and II.

Hardware stores.

Hat cleaning and blocking.

Hobby shops.

Hospitals.

Interior decorating, costuming and draperies.

Jewelry stores.

Laboratories.

Laundries.

Lawn mower sales.

Leather good stores.

Luggage shops.

Mail order offices.

Meat, fish and seafood markets.

Medical buildings and clinics, and dental clinics.

Messenger offices.

Millinery stores.

Motorcycle sales and service.

Music, radio and television shops and repairs.

Newsstands.

Nursing homes.

Optical stores.

Paint and wallpaper stores.

Parking lots (commercial).

Parks and public recreational facilities.

Pawnshops.

Pet shops, with property enclosed to prevent any noxious odors.

Photograph studios and galleries.

Plant nurseries (no outside bulk storage of mulch, topsoil, etc.).

Post offices.

Printing services.

Professional offices and office buildings.

Resort dwellings.

Restaurants.

Sale of alcoholic beverage, package only.

Schools for business training.

Schools, private or parochial.

Shoe repair shops.

Shoe stores.

Single-family residence.

Soft drink stands.

Souvenir stores.

Stationery stores and bookstores.

Tailor shops.

Tearooms.

Telephone and telegraph stations and exchanges.

Television and broadcasting stations, including studios, transmitting stations and towers and other incidental uses usually pertaining to such stations.

Theaters, but no drive-ins.

Ticket offices and waiting rooms for common carriers.

Tobacco stores.

Upholstery shops.

Wearing apparel stores.

Worship, places of.

c. Permitted uses with conditions are as follows (see division 5, subdivision II, of this article):

Assisted living facility.

Automobile and motorcycle repair (major) and paint and body work.

Boat sales and service.

Cabinetmaking and carpentry.

Dry cleaning plants, accessory to pickup stations.

Farm machinery sales and service.

Gasoline service stations.

Manufacturing, compounding, processing, packaging, storage, treatment or assembly of certain products.

Outdoor restaurant seating.

Outside sale of mobile homes.

Preexisting use.

Substations, and transmission facilities.

Security mobile home.

Self storage mini-warehouses.

Tourist efficiencies and hotels and motels.

Treatment and recovery facility.

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(2) *Accessory buildings or uses.* Accessory buildings and uses customary to commercial and residential uses are permitted. (Refer to definition cited in section 62-1102 and standards cited in section 62-2100.5). Additional accessory uses are as follows:

a. Completely enclosed lumber sales are permitted as an accessory use to hardware and supply stores.

b. A roadside stand used as provided in chapter 86, article IV, is permitted as an accessory use.

(3) *Conditional uses.* Conditional uses are as follows:

Alcoholic beverages for on-premises consumption.

Change of nonconforming agricultural use.

Commercial entertainment and amusement enterprises (small scale and large scale).

Commercial/recreational and commercial/industrial marinas.

Land alteration (over five acres and up to ten acres).

Performance Overlay Districts.

Plant nurseries (with outside bulk storage of mulch, topsoil, etc.)

Security mobile home.

Substantial expansion of a preexisting use.

Towers and antennas.

Trailer and truck rental.

(4) *Minimum lot size.* Except for gasoline service stations, an area not less than 7,500 square feet is required, having a width and depth of not less than 75 feet.

(5) *Setbacks.*

a. *Generally.*

1. Gasoline Service Station setbacks in this zoning classification shall be governed by section 62-1835.7.

2. The front setback shall be 25 feet from the front lot line.

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3. The rear setback shall be 15 feet from the rear lot line. However, if the rear lot line abuts a dedicated 20-foot alley or roadway, the setback shall be five feet.

4. Side Setbacks:

a. Where a side lot line abuts a residential zone, such side setback shall be a minimum of 15 feet.

b. Where a side lot line abuts a non-residential zone, such side setback shall be 5 feet.

c. Where a side lot line abuts a combination of commercial, industrial or residential zonings, the respective side setbacks as stated in a. or b. above shall apply to the affected side yard area.

d. Where a 20 foot dedicated alleyway or roadway exists adjacent to or abutting the rear lot line, and the zoning adjacent to the side yard area is non-residential, no side setback is required when a three hour firewall is constructed along the side lot line. However, where the side lot line abuts a residential zone on that side, the minimum side setback shall be 15 feet.

e. Notwithstanding the requirements of section 5(a)(4)(b) above, where a 20-foot dedicated alleyway or roadway does not exist adjacent to or abutting the rear lot line, lots whose sides abut non-residential zonings may utilize a ten-foot paved driveway setback along one side and a zero foot setback on the other provided a three-hour firewall is constructed where the building is proposed within five feet of the side property line. However, where the side lot line abuts a residential zone on that side, the minimum side setback shall be 15 feet.

f. On a corner lot, the side street setback shall be 15 feet. If a corner lot is contiguous to a key lot, then the side street setback shall 25 feet.

5. *Within the Merritt Island Redevelopment Area.* On all lots in the Merritt Park Place Subdivision except corner lots, structures shall be set back not less than 15 feet from the front lot line where parking is located to the side or rear of the principal structure. Otherwise, all other provisions as described above shall apply.

b. *Breezeway/visual corridor.* All riverfront and oceanfront properties are subject to breezeway/visual corridor regulations enumerated in section 62-2105.

(6) *Minimum floor area.* All structures shall contain a minimum of 300 square feet of floor area.

(7) *Structural height standards.*

a. Where the property abuts any other land located in the GU, AGR, AU, ARR, REU, RU-1-7, RU-1-9, RU-1-11, RU-1-13, RR-1, EU, EU-1, EU-2, SEU, SR, RVP, TR-1-A, TR-1, TR-2, TR-3, TRC-1, RRMH-1, RRMH-2.5, RRMH-5, EA, PA or GML zoning classification, the maximum height threshold of any structure or building thereon shall be 35 feet.

b. Where the property abuts any other land located in the RA-2-4, R-2-6, RA-2-8, RA-2-10, RU-2-4, RU-2-6, RU-2-8, RU-2-10, RU-2-12, RP or BU-1-A zoning classification, the maximum height threshold of any structure or building thereon shall be 45 feet.

c. Where the property abuts any other land located in the RU-2-15, RU-2-30, BU-1, BU-2, PIP, PBP, IU, IU-1, TU-1 or TU-2 zoning classification, the maximum height threshold of any structure or building thereon shall be 60 feet.

d. Where any structure or building exceeds 35 feet in height, all conditions enumerated in section 62-2101.5 as applicable shall be fully satisfied.

e. Structures or buildings may not exceed the maximum height thresholds stated in this subsection unless otherwise permitted by section 62-2101.5.

(8) *Fencing and buffering.* See article XIII, division 2, of this article, pertaining to landscaping.

(9) *Metal buildings.* Metal buildings shall be permitted in this zoning classification subjectto the restrictions presented in section 62-2115.

(10) *Maximum floor area ratio.* The floor area ratio shall be governed by section 62-2110.

(Code 1979, § 14-20.12(B); Ord. No. 95-17, § 1, 4-11-95; Ord. No. 95-47, §§ 52, 53, 10-19-95; Ord. No. 95-49, §§ 3, 9, 12, 18, 21, 10-19-95; Ord. No. 95-51, § 4, 10-19-95; Ord. No. 96-16, §§ 55, 56, 3-28-96; Ord. No. 96-46, § 14, 10-22-96; Ord. No. 97-23, § 2, 7-8-97; Ord. No. 97-40, § 2, 10-14-97; Ord. No. 99-07, § 12, 1-28-99; Ord. No. 99-24, § 9, 4-8-99; Ord. No. 2000-50, § 3, 10-31-00; Ord. No. 01-07, § 2, 2-20-01; Ord. No. 01-30, § 10, 5-24-01; Ord. No. 2002-42, § 4, 8-27-02; Ord. No. 2002-43, § 2, 8-27-02; Ord. No. 2002-49, § 33, 9-17-02; Ord. No. 2003-03, § 27, 1-14-03; Ord. No. 03-36, § 1, 8-7-03; Ord. No. 04-29, § 26, 8-5-04; Ord. No. 2004-52, § 23, 12-4-04; Ord. No. 05-27, § 3, 5-19-05; Ord. No. 05-40, § 7, 8-23-05; Ord. No. 06-21, § 3, 4-25-06; Ord. No. 06-36, § 3, 5-24-06; **Ordinance No. 2007-059, enacted December 6, 2007.**)

Sec. 62-1483. Retail, warehousing and wholesale commercial, BU-2.

The BU-2 retail, warehousing and wholesale commercial zoning classification encompasses lands devoted to general retail and wholesale business, contracting and heavy repair services and warehousing activities. Where this zoning classification is presently located or is proposed to be located adjacent to the lagoonal water edge or fronts on the ocean, water-dependent uses such as fish, shellfish and wildlife production, recreation, water-dependent industry and utilities, marinas and navigation shall have the highest priority. The next highest priority for uses along the waterfront include water-related uses such as utilities, commerce and industrial uses. Water-enhanced uses such as restaurants and tourist attractions shall have the next highest use priorities. Of lowest priority are those uses which are nonwater-dependent and nonwater-enhanced, and those which result in an irretrievable commitment of coastal resources.

(1) *Permitted uses.*

a. All business uses and all materials and products shall be confined within substantial buildings completely enclosed with walls and a roof, however, retail items of substantial size or which of necessity must remain outside of a building may be permitted to be displayed outside the building. Such retail items include but are not limited to motor vehicles, utility sheds, nursery items such as plants and trees, boats and mobile homes.

b. All uses listed below, or other uses of a similar nature compatible with the character of uses described herein:

Administrative, executive and editorial offices.

Antique shops.

Aquariums.

Art goods and bric-a-brac shops.

Artists' studios.

Auditoriums.

Automobile hire.

Automobile repairs, minor and major, as defined in Section 62-1102 (also see Section 62-1837.6).

Automobile washing.

Bait and tackle shop.

Bakery sales, with baking permitted on the premises.

Banks and financial institutions.

Barbershops and beauty parlors.

Bicycle sales and service.

Billiard rooms and electronic arcades (soundproofed).

Bookstores.

Bottling beverages.

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Bowling alleys (soundproofed).

Cafeterias.

Ceramics and pottery; finishing and sales, including production and firing.

Child or adult day care centers.

Civic, philanthropic or fraternal organizations.

Colleges and universities.

Commercial schools offering instruction in dramatic, musical or other cultural activity, including martial arts.

Confectionery and ice cream stores.

Conservatories.

Convenience stores, with or without gasoline sales.

Curio shops.

Dancing halls and academies (soundproofed).

Display and sales rooms.

Dog and pet hospitals and beauty parlors.

Drug and sundry stores.

Dry cleaning and laundry pickup stations.

Dry cleaning plants.

Dyeing and carpet cleaning.

Electrical appliance and lighting fixtures.

Employment agencies.

Feed and hay for animals and stock.

Fertilizer stores.

Florist shops.

Foster homes.

Fraternities and sororities.

Fruit stores (packing on premises).

Funeral homes and mortuaries.

Furniture stores.

Furriers.

Gift shops.

Glass installation.

Grocery stores.

Group homes, levels I and II.

Hardware stores.

Hat cleaning and blocking.

Hobby shops.

Hospitals.

Ice plants.

Interior decorating, costuming and draperies.

Jewelry stores.

Kindergartens.

Laboratories.

Laundries.

Lawn mower sales.

Leather good stores.

Luggage shops.

Mail order offices.

Meat markets.

Medical buildings and clinics, and dental clinics.

Messenger offices.

Millinery stores.

Music, radio and television shops and repairs.

Newsstands.

Nursing homes.

Optical stores.

Paint and body shops.

Paint and wallpaper stores.

Parking lots (commercial).

Parks and public recreational facilities.

Pawnshops.

Pet kennels.

Pet shops, with property enclosed to prevent any noxious odors.

Photograph galleries.

Photographic studios.

Plant nurseries.

Plumbing and electrical shops.

Post offices.

Printing services.

Professional offices and office buildings.

Resort dwellings.

Restaurants.

Sale of alcoholic beverages, package only.

Schools for business training.

Schools, private or parochial.

Seafood processing plants not located within 300 feet of any residential zone boundary.

Sharpening and grinding shops.

Ship chandlery.

Shoe repair shops.

Shoe stores.

Single-family residence.

Soft drink stands.

Souvenir stores.

Stationery stores and bookstores.

Tailor shops.

Tearooms.

Telephone and telegraph stations and exchanges.

Television and broadcasting stations, including studios, transmitting stations and towers, power plants and other incidental uses usually pertaining to such stations.

Testing laboratories.

Theaters, but no drive-ins.

Ticket offices and waiting rooms for common carriers.

Tobacco stores.

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Upholstery shops.

Wearing apparel stores.

Welding repairs (except metal fabrication).

Wholesale salesroom and storage rooms.

Worship, places of.

c. Permitted uses with conditions are as follows (see division 5, subdivision II, of this article):

Assisted living facility.

Automobile and motorcycle repair (major) and paint and body work.

Automobile sales and storage.

Automobile tires and mufflers (new) (sales and service).

Boat sales and service.

Building materials and supplies.

Cabinetmaking and carpentry.

Cemeteries and mausoleums.

Commercial entertainment and amusement enterprises (small scale), subject to conditions in section 62-1921.

Contractor's offices, plants and storage yards.

Crematoriums.

Engine sales and service.

Farm machinery sales and services.

Garage or mechanical service.

Gasoline service stations.

Manufacturing, compounding, processing, packaging, storage, treatment or assembly of

HEARING EXHIBIT - 00000551

certain products.

Mini-warehouses.

Minor automobile repairs.

Mobile home and travel trailer sales.

Motorcycle sales and service.

Outdoor restaurant seating.

Outside sale of mobile homes.

Preexisting use.

Railroad, motor truck and water freight and passenger stations.

Recovered materials processing facility.

Security mobile home.

Service station for automotive vehicles and U-haul service.

Substations, and transmission facilities.

Tourist efficiencies and hotels and motels.

Treatment and recovery facility.

Warehouses.

(2) *Accessory buildings or uses.* Accessory buildings and uses customary to commercial and residential uses are permitted. (Refer to definition cited in section 62-1102 and standards cited in section 62-2100.5). Additional accessory uses are as follows:

A roadside stand used as provided in chapter 86, article IV is permitted as an accessory use.

(3) *Conditional uses.* Conditional uses are as follows:

Alcoholic beverages for on-premises consumption.

Automobile sales and storage (under one acre in the Merritt Island Redevelopment Area).

Change of nonconforming agricultural use.

EXHIBIT - 00000552

Commercial entertainment and amusement enterprises (large scale).

Commercial/recreational and commercial/industrial marinas.

Flea markets (recreational vehicles may be an accessory use pursuant to division 5, subdivision II, of this article).

Land alteration (over five acres and up to ten acres).

Security mobile home.

Substantial expansion of a preexisting use.

Towers and antennas.

(4) *Minimum lot size.* Except for gasoline service stations, an area not less than 7,500 square feet is required, having a width and depth of not less than 75 feet.

(5) *Setbacks.*

a. *Generally.*

1. Gasoline Service Station setbacks in this zoning classification shall be governed by section 62-1835.7.

2. The front setback shall be 25 feet from the front lot line.

3. The rear setback shall be 15 feet from the rear lot line. However, if the rear lot line abuts a dedicated 20-foot alley or roadway, the setback shall be five feet.

4. Side Setbacks:

a. Where a side lot line abuts a residential zone, such side setback shall be a minimum of 15 feet.

b. Where a side lot line abuts a non-residential zone, such side setback shall be 5 feet.

c. Where a side lot line abuts a combination of commercial, industrial or residential zonings, the respective side setbacks as stated in a. or b. above shall apply to the affected side yard area.

d. Where a 20 foot dedicated alleyway or roadway exists adjacent to or abutting the rear lot line, and the zoning adjacent to the side yard area is non-residential, no side setback is required when a three hour firewall is constructed along the side lot line. However, where the side lot line abuts

a residential zone on that side, the minimum side setback shall be 15 feet.

e. Notwithstanding the requirements of section 5(a)(4)(b) above, where a 20-foot dedicated alleyway or roadway does not exist adjacent to or abutting the rear lot line, lots whose sides abut non-residential zonings may utilize a ten-foot paved driveway setback along one side and a zero foot setback on the other provided a three-hour firewall is constructed where the building is proposed within five feet of the side property line. However, where the side lot line abuts a residential zone on that side, the minimum side setback shall be 15 feet.

f. On a corner lot, the side street setback shall be 15 feet. If a corner lot is contiguous to a key lot, then the side street setback shall 25 feet.

b. *Breezeway/visual corridor.* All riverfront and oceanfront properties are subject to breezeway/visual corridor regulations enumerated in section 62-2105.

(6) *Minimum floor area.* All structures shall contain a minimum of 300 square feet of floor area.

(7) *Structural height standards.*

a. Where the property abuts any other land located in the GU, AGR, AU, ARR, REU, RU-1-7, RU-1-9, RU-1-11, RU-1-13, RR-1, EU, EU-1, EU-2, SEU, SR, RVP, TR-1-A, TR-1, TR-2, TR-3, TRC-1, RRMH-1, RRMH-2.5, RRMH-5, EA, PA or GML zoning classification, the maximum height threshold of any structure or building thereon shall be 35 feet.

b. Where the property abuts any other land located in the RA-2-4, RA-2-6, RA-2-8, RA-2-10, RU-2-4, RU-2-6, RU-2-8, RU-2-10, RU-2-12, RP or BU-1-A zoning classification, the maximum height threshold of any structure or building thereon shall be 45 feet.

c. Where the property abuts any other land located in the RU-2-15, RU-2-30, BU-1, BU-2, PBP, PIP, IU, IU-1, TU-1 or TU-2 zoning classification, the maximum height threshold of any structure or building thereon shall be 60 feet.

d. Where any structure or building exceeds 35 feet in height, all conditions enumerated in section 62-2101.5 as applicable shall be fully satisfied.

e. Structures or buildings may not exceed the maximum height thresholds stated in this subsection unless otherwise permitted by section 62-2101.5.

(8) *Fencing and buffering.* See article XIII, division 2, of this article, pertaining to landscaping.

(9) *Metal buildings.* Metal buildings shall be permitted in this zoning classification subject to the restrictions presented in section 62-2115.

(10) *Maximum floor area ratio.* The floor area ratio shall be governed by section 62-2110.

(Code 1979, § 14-20.12(C); Ord. No. 93-20, § 1, 6-22-93; Ord. No. 95-47, §§ 54, 55, 10-19-95; Ord. No. 95-49, §§ 9, 12, 18, 10-19-95; Ord. No. 95-51, § 5, 10-19-95; Ord. No. 96-16, §§ 57, 58, 3-28-96; Ord. No. 96-46, § 15, 10-22-96; Ord. No. 97-23, § 3, 7-8-97; Ord. No. 97-40, § 3, 10-14-97; Ord. No. 98-11, § 4, 2-26-98; Ord. No. 99-07, § 12, 1-28-99; Ord. No. 99-24, §§ 3, 7, 4-8-99; Ord. No. 2000-50, § 4, 10-31-00; Ord. No. 01-07, § 3, 2-20-01; Ord. No. 01-30, § 11, 5-24-01; Ord. No. 2002-42, § 5, 8-27-02; Ord. No. 2002-43, § 3, 8-27-02; Ord. No. 2002-49, § 34, 9-17-02; Ord. No. 2003-03, § 28, 1-14-03; Ord. No. 03-36, § 1, 8-7-03; Ord. No. 04-29, § 27, 8-5-04; Ord. No. 2004-52, § 24, 12-4-04; Ord. No. 05-27, § 3, 5-19-05; Ord. No. 05-40, § 8, 8-23-05; **Ordinance No. 2007-059, enacted December 6, 2007.)**

Secs. 62-1484--62-1510. Reserved.

Subdivision VII.

Tourist Commercial and Transient Tourist Use

Sec. 62-1511. General tourist commercial, TU-1.

The TU-1 general tourist commercial zoning classification encompasses lands devoted to general tourist-related activities and recognizes the need for higher densities for motels and hotels. Also, a limitation of kitchen facilities is specified to prevent the conversion of motel and hotel units to permanent residential use. For purposes of this section, permanent residential use shall mean any use of one dwelling unit for more than three months by one family or one individual or any dwelling unit for which a lease is available for a period of time exceeding three months. The uses listed in subsection (1) of this section, or other uses of a similar nature that are compatible with the character of the uses specifically set forth in this section, are permitted.

(1) *Permitted uses.*

a. Permitted uses are as follows:

Art galleries, libraries and museums.

Civic, philanthropic or fraternal organizations.

Hotels and motels.

Parks and public recreational facilities.

Resort dwellings.

Restaurants.

Sale of alcoholic beverages, package only.

Single-family residence.

HEARING EXHIBIT - 00000555

S.F. HOLDEN, INC.

REAL ESTATE APPRAISERS AND CONSULTANTS
Licensed Real Estate Broker

Square Lake Centre, Suite 10 8259 North Military Trail Palm Beach Gardens, Florida 33410-6352
(561) 626-2004 Fax (561) 622-7631

ABRIDGED QUALIFICATIONS

PHILIP M. HOLDEN, MAI

State-Certified General Real Estate Appraiser RZ 1666

Philip M. Holden, who holds the MAI designation in the Appraisal Institute, is the President of S.F. Holden, Inc., a real estate appraisal and consulting firm established in 1964. He is a registered real estate broker in the State of Florida and is past-president of the Society of Real Estate Appraisers, Palm Beach County Chapter and the Florida Chapter of the American Society of Farm Managers and Rural Appraisers. Mr. Holden has been appraising real estate since September 1974, and has successfully completed the following courses or seminars given by real estate appraisal organizations:

Appraisal Courses and Seminars
Valuation of Less Than Fee - May 1995, 1996
Riparian Rights - May 1994
Easement Valuation - May 1994
Cattle Grazing Seminar - May 1993
Permanent Plantings – October 1997
Appraising Rural Properties – May 1997
Realtors Land Institute Citrus Course – May 1999
University of Florida, Citrus Seminar – April 1999
Highest/Best Use/ Valuation Techniques – May 2000
Attacking and Defending Appraisals – June 2000
SFWMD Federal Land Acquisitions – May 2001
SJRWMD Land Acquisitions – December 2001
SFWMD Oil & Gas Mineral Valuation – May 2002
SFWMD Everglades Restoration – May 2002
USPAP and USPAP Core Law – November 2002
Appraising the Appraisal – 2003
Automation in Appraisal Reporting – 2003
SFWMD Appraisal Seminar – May 2003
SFWMD Appraisal Seminar – May 2004
SFWMD Appraisal Seminar – May 2005
SFWMD Appraisal Seminar – May 2006
SFWMD Appraisal Seminar – May 2007
Valuation of Conservation Easements – Jan 2008

Appraisal Institute
USPAP Update - December 1995
Limited Appraisals/Evaluations - May 1995
Income Valuation - March 1995
Powerline Easements - April 1994
Americans Disabilities Act - February 1994
Standards of Professional Practice – September 1997
USPAP Core Law – May 1998
Partial Interest Valuation – August 1999
FL State Law for RE Appraisers – 2003
Uniform Standards for Fed. Land Acquisitions – 2004
400 USPAP Course – October 2004
USPAP – December 2005, August 2006
Core Law – January 2006
Code of Ethics/Professional Bus. Practice – 12/2006
Uniform Standards for Federal Land Acq. – 1/2007

American Institute of Real Estate Appraisers
Course 1-A - August 1976
Course VIII - June 1977
Course 1-B - March 1978 and 1986
Course II - March 1979
Standards of Professional Practice – June 1992

Real Estate Broker
Bert Rogers – June 2004

Society of Real Estate Appraisers
Course 101 - June 1976
Course R-2 - January 1977
Course 201 - January 1978 & 1984
Litigation Valuation - February 1988
Standards of Professional Practice - March 1989

In addition to the above listed courses, Mr. Holden has attended many seminars and two-day courses. He was also an instructor for the Appraisal Institute, Course 101. Recent speaking engagements include the Realtor's Land Institute, the International Association of Assessing Officers, and the University of Florida IFAC course in appraising citrus. Mr. Holden is qualified as an expert in the courts and also served as Special Master for the Palm Beach County Property Appraisal Adjustment Board. Some of the major property types which Mr. Holden has appraised are: agricultural (farms, ranches, citrus groves, dairies) commercial (shopping centers, offices); industrial properties, and residential properties (individual homes and subdivisions). Mr. Holden specializes in unique and special-purpose properties including rights-of-way (proposed and abandoned), one-of-a-kind buildings and partially-completed buildings, marinas, packing houses, damaged properties and churches. Other areas of specialization include the analysis of various interests such as leasehold/leased fee, partial-ownership interests and easements including under- and above-ground, flowage, and conservation, and other uncommon ownerships. Typically, the appraisal work has been for sale and/or purchase, mortgages, litigation (eminent domain, bankruptcy, dissolution of real estate) and taxation issues.

S.F. HOLDEN, INC.

REAL ESTATE APPRAISERS AND CONSULTANTS
Licensed Real Estate Broker

Square Lake Centre, Suite 10 8259 North Military Trail Palm Beach Gardens, Florida 33410-6352
(561) 626-2004 Fax (561) 622-7631

ABRIDGED QUALIFICATIONS

DONALD G. BLAUVELT, MAI, SRA
Florida State-Certified General Real Estate Appraiser RZ 511

Donald G. Blauvelt has been an independent real estate appraiser since 1972 and is a past-president of the Society of Real Estate Appraisers Oklahoma Green Country Chapter. He has been a state certified General Real Estate Appraiser in Florida since the inception of the national state certification requirements, with current licensure through November 30, 2008. Mr. Blauvelt has successfully completed the following courses or seminars by real estate appraisal organizations:

America Institute of Real Estate Appraisers
Course 1A, Real Estate Principles, 1972
Course 1B, Capitalization Techniques, 1974
Course II, Urban Property, 1977
Course IV, Litigation Valuation, 1988
Course VI, Investment Analysis, 1977
Course VIII, Single Family Property, 1974

Society of Real Estate Appraisers
Course 101, Real Estate Principles, 1972
Course 201, Income Property Appraising, 1973
Course 301, Special Applications, 1975

Appraisal Seminars
Business Practices and Ethics (AI), 2006
Standards of Professional Practice, 1992
USPAP Core Law for Appraisers, 1994, 1997
USPAP National Update (bi-annually), 1996-2004, 2006
Florida Appraisal Law Update, 1996-2004, 2006
Litigation Valuation, 1993

In addition to the above, Mr. Blauvelt has attended numerous seminars sponsored by the Appraisal Institute, SFWMD and others regarding continuing education requirements of the Appraisal Institute and State of Florida's appraisal licensure.

Mr. Blauvelt has appraisal assignment experience in the states of Alabama, Arkansas, Arizona, California, Connecticut, Florida, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Louisiana, Massachusetts, Mississippi, Missouri, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas and Virginia. Mr. Blauvelt has qualified as an expert in multiple courts in multiple states.

Major property types that Mr. Blauvelt has appraised in the past or has continuing valuation assignments include agricultural properties (farms, ranches, citrus groves); commercial properties (many types of single and multi-tenant income producing or owner-occupied); industrial properties; special purpose or unique properties; residential properties (planned subdivisions); and vacant land.

Clients include federally-regulated lenders, insurance companies, private individuals and government agencies.

Florida Power & Light Co., P.O. Box 14000, Juno Beach, Florida 33408-0420

May 8, 2008

Re: **Desoto County, 20 acres,**
Parcel ID., 27-36-25-0000-0010-0000

To Whom It May Concern:

The owners of the above-mentioned property presently enjoy access to their property through lands owned by FPL. FPL agrees that access to these lands will continue uninterrupted. Notwithstanding the access roadway may be revised to conform to future development of the lands.

Sincerely,

Buck Martin (for)

J. T. Corson
Corporate Real Estate Area Manager
Juno Beach, FL.

EXHIBIT - 00000558

6

FPL's Response to Staff's Fourth Request for Production of Documents (No. 17)

HEARING EXHIBIT - 00000560

Q.

Please provide all workpapers to support FPL's assertion on Page 17 of its petition (Items 41) that:

a. In 2011, the first year when all three projects are in service for the full year, the system average bill impact is projected to be an increase of 83 cents per 1000 kWh;

b. Over the first 25 years of operations (2009-2033) the system average bill impact is projected to be an increase of 31 cents for the average customer.

A.

Documents responsive to this request are provided as Bates No. ECRC-08-4707.

System Average Rate Impact Calculation- Solar Projects

	LOAD DATA					ANNUAL REVENUE REQUIREMENTS $MILLIONS			1000 KWh BILL IMPACT	SYSTEM AVERAGE RATE
YEAR	FPL NEL ENERGY (GWH)	DSM (GWH)	NEL ENERGY - DSM (GWH)	LINE LOSS (GWH)	TOTAL SALES (GWH)	BASE CASE	CASE WITH SOLAR PROJECTS	DIFFERENCE	$	CENTS/kWh
2008	118,357	132	118,225	7,637	110,588	6,586	6,586	-		
2009	121,852	266	121,586	7,854	113,731	6,372	6,376	4	0.039	0.004
2010	127,004	409	126,595	8,178	118,417	6,840	6,888	48	0.403	0.040
2011	131,862	558	131,305	8,482	122,822	6,263	6,365	102	0.827	0.083
2012	136,554	713	135,841	8,775	127,066	6,702	6,790	88	0.695	0.070
2013	141,374	874	140,500	9,076	131,424	7,204	7,285	81	0.616	0.062
2014	148,752	1,042	147,710	9,542	138,168	8,244	8,319	75	0.546	0.055
2015	152,495	1,210	151,285	9,773	141,512	8,996	9,065	69	0.486	0.049
2016	156,384	1,405	154,979	10,012	144,967	10,096	10,158	63	0.432	0.043
2017	160,246	1,599	158,647	10,249	148,398	10,966	11,029	63	0.421	0.042
2018	164,114	1,599	162,515	10,498	152,017	11,286	11,342	56	0.369	0.037
2019	168,378	1,599	166,779	10,774	156,005	11,803	11,857	54	0.348	0.035
2020	173,202	1,599	171,603	11,086	160,517	11,903	11,952	49	0.304	0.030
2021	177,895	1,599	176,296	11,389	164,908	12,752	12,802	50	0.303	0.030
2022	182,346	1,599	180,747	11,676	169,071	14,078	14,125	47	0.279	0.028
2023	186,940	1,599	185,341	11,973	173,368	15,348	15,392	45	0.257	0.026
2024	191,654	1,599	190,055	12,278	177,777	16,807	16,847	39	0.222	0.022
2025	196,447	1,599	194,848	12,587	182,261	18,361	18,396	35	0.192	0.019
2026	201,221	1,599	199,622	12,896	186,726	20,125	20,160	35	0.187	0.019
2027	206,047	1,599	204,448	13,207	191,241	22,337	22,366	29	0.153	0.015
2028	211,066	1,599	209,467	13,532	195,936	24,252	24,282	29	0.150	0.015
2029	216,258	1,599	214,659	13,867	200,792	26,335	26,360	25	0.125	0.013
2030	221,502	1,599	219,903	14,206	205,697	28,658	28,679	21	0.100	0.010
2031	226,895	1,599	225,296	14,554	210,742	31,212	31,228	17	0.078	0.008
2032	232,995	1,599	231,396	14,948	216,448	34,602	34,615	12	0.057	0.006
2033	238,093	1,599	236,494	15,278	221,217	39,058	39,068	10	0.044	0.004
2034	236,372	1,599	234,773	15,166	219,606	40,962	40,967	5	0.023	0.002
2035	242,100	1,599	240,501	15,536	224,964	43,971	43,972	2	0.007	0.001

fist full year operation 0.827

25 year average (2009-2033) 0.305

FCRC-08-4707

HEARING EXHIBIT - 00000562

7

FPL's Response to Staff's Fifth Request for Production of Documents (No. 23)

HEARING EXHIBIT - 00000563

Q.

Regarding the exclusion devices FPL identified as the additional work of the St. Lucie Cooling Water System Inspection and Maintenance Project, please provide workpapers to support the estimates of the total capital cost $3.75 million specified on page 12 of witness Labauve's testimony dated 08/04/08.

A.

Documents responsive to this request are provided as Bates No. ECRC-08-8195.

PROJECT TITLE: OCEAN INTAKE TURTLE EXCLUDERS

CAR NO. 07-038

CONCEPTUAL COST ESTIMATE

Engineering and Design	$	120,000
Drawings and specs		25,000
Permits		5,000
Materials		
Fabrication of frames, trays, panels	$	1,095,000
Implementation		
Clean sub structure @ openings	$	90,000
Install excluder components		1,750,000
Video inspect/Oversight		75,000
Project Support		
Project Manager	$	145,000
Project controls		35,000
Project Supervision		85,000
Contingency		
Engineering	$	20,000
Materials		100,000
Implementation		150,000
Project Support		25,000
Total	$	3,705,000

ANNUAL MAINTENANCE COST

Quarterly inspect, clean, and R & R panels($37,500)	$	150,000

8

FPL's Response to Staff's Fifth Request for Production of Documents (No. 25)

Q.

Regarding the NASA KSC Center Enhanced Use Lease for FPL's Space Coast Solar Project, please provide:

a. The Property Market Value Analysis FPL performed before entering the lease to justify the Fair Market Value of the Phase 1 property $75,000 per acre specified in article 3.1 of the Lease.

b. The analysis performed before entering the lease to justify the Fair Lease Value of the Leased property $7,500 per acre per year specified in article 3.1 of the Lease.

A.

a. FPL relied on the property appraisal that was conducted for the site to justify the Fair Market Value of the property at $75,000 per acre. This appraisal was previously produced in response to Staff's Fourth Request for Production of Documents No. 12(b) (Bates No. ECRC 08-679 through 08-764). In addition, based on verbal discussions with NASA prior to signing the lease, this appraised value is consistent with (and is lower than) NASA's independent appraisal of the property.

b. The value of the Leased property was negotiated by FPL and NASA-KSC by utilizing an Income Capitalization Approach, a common and acceptable real estate appraisal technique. A "ground lease" must be long enough to make the transaction desirable to the tenant (i.e. FPL) and landlord/landowner (i.e. NASA-KSC). Such leases often have terms of 50 years or longer and a lease for 99 years is not uncommon. The value of a ground lease is usually determined by dividing the ground rent by an appropriate "capitalization rate." The subject property was appraised at $75,000 per acre, utilizing an acceptable "capitalization rate" or "discount rate" of 10%. The parties discussed the Fair Lease Value of $7,500/acre on several occasions and agreed that the method used to arrive at the Fair Lease Value was equitable to both parties.

NASA JOHN F. KENNEDY SPACE CENTER

ENHANCED USE LEASE

This Enhanced Use Lease (the "**Lease**") is made as of the date set forth below by the signatories, by and between the NATIONAL AERONAUTICS AND SPACE ADMINISTRATION, an Agency of the United States, John F. Kennedy Space Center, Kennedy Space Center, Florida, as the lessor (hereinafter "**NASA-KSC**"), and Florida Power & Light Company, a corporation organized and existing under the laws of the state of Florida, as the lessee (hereinafter "**FPL**"). This Lease is made under the authority of section 315 of the National Aeronautics and Space Act of 1958, as amended (42 U.S.C. §2459j) with reference to the following facts:

RECITALS

A. NASA-KSC is committed to using its real property assets to efficiently support the Nation's space exploration activities and enable the greatest public benefit from the application of NASA-KSC technology and resources acquired pursuant to its mission.

B. As the Nation's primary space launch facility for human and robotic space exploration missions, NASA-KSC is a significant Federal consumer of electric power, and pursuant to 42 U.S.C. §8251, *as amended*, and Executive Order 13423, NASA-KSC is committed to expanding the use of renewable energy within its facilities by implementing renewable energy projects and by purchasing electricity from renewable energy sources that will reduce emissions contributing to air pollution and global climate change.

C. FPL, serving as Florida's largest electric utility provider and the sole supplier of electric power to NASA-KSC, is committed to increasing the contribution of renewable energy to Florida's electric power supply by developing new generating capacity utilizing renewable energy sources such as solar, wind, and biomass.

D. In furtherance of their respective missions and energy objectives, NASA-KSC and FPL (hereinafter referred to jointly as "the **Parties**") entered into a Memorandum of Understanding ("**MOU**") on December 13, 2007, to collaborate in determining the technical and financial feasibility of developing renewable energy projects using the land and/or facilities available at NASA-KSC.

E. FPL, pursuant to the MOU, has proposed to develop a major photovoltaic power generation facility ("**FPL PV Facility**") on vacant land owned by NASA-KSC in a phased development plan that will harness solar power to generate up to fifteen (15)

HEARING EXHIBIT - 00000568

megawatts of electricity using the intellectual capacity of NASA-KSC and commercial technology originally developed by NASA-KSC as a power source for the International Space Station, other Earth-orbiting satellites, and spacecraft involved in planetary exploration.

F. Accordingly, the Parties have agreed to enter into this Lease for the leased Property defined in section 1.3 below, in accordance with the terms and conditions set forth herein, for the purpose of developing and operating a PV facility to generate renewable energy for use and distribution by both FPL and NASA-KSC. The Parties acknowledge and agree that the leased Property is not being provided to FPL as Government-furnished property under any contract or subcontract, and FPL agrees that it shall not charge or submit for payment any consideration provided pursuant to this Lease as a direct cost or charge under any such contract or subcontract.

NOW, THEREFORE, NASA-KSC and FPL agree as follows:

ARTICLE 1 PROPERTY

1.1 Lease of Property: FPL PV Facility Phase 1. NASA-KSC hereby leases to FPL, and FPL hereby leases from NASA-KSC, for the term set forth in section 2.1 and subject to the covenants hereinafter set forth, the property located on Kennedy Space Center designated as FPL PV Facility Phase 1, encompassing sixty (60) acres, more or less, as legally described on the survey map attached hereto as Exhibit A ("**Phase 1**").

1.2 Option to Lease Property: FPL PV Facility Phase 2. NASA-KSC hereby grants to FPL an option to lease for the term set forth in section 2.1 and subject to the mutual agreement of the Parties and the covenants hereinafter set forth, the property located on Kennedy Space Center designated as FPL PV Facility Phase 2, encompassing forty-eight (48) acres, more or less, as legally described on the survey map attached hereto as Exhibit A ("**Phase 2**"), provided that the effective date of FPL's leasehold interest therein and obligations hereinafter set forth shall commence on a date determined by mutual agreement of the Parties, but not later than August 1, 2020, and provided further, that FPL will provide to NASA-KSC written notice of its intent to exercise said option at least sixty (60) days prior to the exercise thereof. At FPL's request, and at NASA-KSC's sole discretion, additional acreage may be included in Phase 2 beyond that described in Exhibit A contingent upon the completion of additional environmental analysis as may be required by NASA-KSC. The parties agree that of the forty-eight (48) acres presently encompassing Phase 2, a total of up to eight (8) acres will be unsuitable or unavailable for FPL use and will not be included in determination of consideration due to NASA for Phase 2. Phase 1 and Phase 2 together shall be referred to as the "**Phases**" and, individually, each a "**Phase**". This option is contingent upon FPL providing, and NASA-KSC accepting, the proposed consideration for the Phase 2 acreage. The Parties intend that the consideration for Phase 2 will be a to-be-negotiated expansion of the NASA PV Facility. However, NASA-KSC, at its sole discretion, reserves the right to receive monetary consideration in lieu of nonmonetary consideration for the Phase 2 acreage.

HEARING EXHIBIT - 00000569

1.3 Property Disposition. The property described in Exhibit A (hereinafter the "**leased Property**") consists of vacant, undeveloped land with no existent utility or other municipal services. FPL acknowledges that it has inspected the leased Property, or has had the leased Property inspected by consultants retained by FPL, and has found it acceptable for the Permitted Use (as defined in section 4.1). FPL accepts the leased Property "AS IS", and acknowledges that NASA-KSC has made no covenant, representation, or warranty of any kind, express or implied, with regard to the suitability of leased Property for the Permitted Use, and that NASA-KSC has no duty to make any improvements to the leased Property.

ARTICLE 2 TERM

2.1 Term of Lease. The term of this Lease for Phase 1 shall be for a period of thirty (30) years, commencing on August 1, 2008 (the "**Phase 1 Commencement Date**") and, unless sooner terminated as hereinafter provided, expiring on July 31, 2038. The term of this Lease for Phase 2 shall commence on the date as set forth in the option notice as provided in section 1.2 (the "**Phase 2 Commencement Date**") and, unless sooner terminated as hereinafter provided, expire thirty (30) years thereafter. The Phase 1 Commencement Date and Phase 2 Commencement Date shall generically for each Phase be referred to as the "**Commencement Date**".

2.2 Modification of Term of Lease for Technology Upgrade.

(a) During the basic term of this Lease, the Parties may desire to upgrade the FPL Facility and NASA PV Facility (as defined in Section 3.2) to incorporate new technology that will increase electric power production and/or improve cost effectiveness. Upon mutual agreement of the parties, the term of this Lease may be extended by up to twenty (20) years, with corresponding modification to consideration, to accommodate the installation and amortization of any such upgrade.

(b) In the event that FPL is unable to use the leased Property due to any of the following: (i) FPL is denied any permits necessary to construct and operate the FPL PV Facility and/or NASA PV Facility; (ii) fire, natural disaster, or other casualty; (iii) hostile acts, warfare, or major accidents; (iv) condemnation for a public or quasi-public use under any statute or by right of eminent domain or private purchase in lieu thereof by any competent authority; then FPL shall have the right to terminate the Lease within thirty (30) days after providing NASA-KSC with written notice. FPL shall also have the right to terminate the Lease within thirty (30) days after providing NASA-KSC with written notice in the event that there is a change in law or applicable regulation and action or inaction by any Federal, state, or local legislative, executive, administrative judicial agency or body which invalidates any government incentive that FPL is to receive for operating a photovoltaic power generation facility. Except for any obligations that specifically survive

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the termination of the Lease as set forth herein, both FPL and NASA-KSC shall be released of any and all liability and obligations specified in the Lease as of the termination date.

2.3 Possession. NASA-KSC shall deliver possession of the leased Property to FPL for each of the Phases described upon the Commencement Date for the particular Phase, and FPL shall not use or occupy the leased Property until such delivery.

2.4 Expiration of the Term: Upon expiration of the term, or upon other termination as provided under this Lease, FPL shall immediately cease all power generation operations at the FPL PV Facility located on the leased Property. Within one hundred eighty (180) days after the expiration, FPL shall remove and properly dispose of all improvements made to the leased Property in accordance with Article 11 of this Lease, whereupon FPL shall vacate and surrender the leased Property to NASA-KSC. Surrender of the leased Property shall not be deemed to be a payment in lieu of any consideration that may be due pursuant to this Lease.

ARTICLE 3 CONSIDERATION

3.1 Fair Market Value. NASA-KSC and FPL agree that the Fair Market Value ("**FMV**") of the Phase 1 property is seventy-five thousand dollars ($75,000) per acre as of the Phase 1 Commencement Date. Accordingly, the Parties agree that the Fair Market Lease Value of the Leased property is seven thousand five hundred dollars ($7,500) per acre per year, which value shall be escalated at 2.5 percent per annum commencing in 2010 for the remaining term of the Lease. The Fair Market Lease Value per acre of the leased Property to be conveyed in Phase 2 shall be the same escalated value as that determined for Phase 1.

3.2 Nonmonetary Consideration. FPL shall provide, no later than twelve (12) months from the Commencement Date of each Phase, nonmonetary consideration in the form of one (1) separate photovoltaic electric power generation system (the "**NASA PV Facility**") to be operated and maintained by FPL for the entire term of the Lease but titled to, and generating electrical power for the exclusive use of, NASA-KSC. The installed capital cost for the design and construction of the NASA PV Facility for Phase 1 shall be six million three hundred fifty-nine thousand and twenty-seven dollars ($6,359,027) as set forth in Exhibit E. The cost to operate and maintain the NASA PV Facility, to include capital replacement costs, as well as the costs of operation and maintenance that are typical for a photovoltaic power generation facility, as specified in Article 7 of the Lease and Exhibit D, shall be no less than one million two hundred thousand dollars ($1,200,000) over the thirty (30) year term as described in Exhibit E. By March 1 of each year of the term, FPL shall provide to NASA-KSC an annual accounting of operations and maintenance costs incurred during the preceding calendar year. The NASA PV Facility shall be sited on the NASA-KSC land identified in Exhibit B to this Lease and shall consist of the buildings, other structures, fixtures, and equipment as specified, designed, and constructed in accordance with the requirements of this Lease. As a condition to the commencement of each Phase of this Lease, FPL shall submit for

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NASA-KSC approval the proposed design and estimated cost of the NASA PV Facility, to include all costs associated with the design, acquisition, construction, and installation of the NASA PV Facility, as well as the projected expenses that FPL will incur to effect the connection to the NASA PV Facility to the NASA-KSC electrical power distribution system. Upon completion of the NASA PV Facility, FPL shall document to the satisfaction of NASA-KSC the consideration value of the NASA PV Facility by submitting to NASA-KSC records of the actual costs and expenses incurred, as well as the projected operating and maintenance expenses.

3.3 Modification of Consideration for Technology Upgrades. In the event the parties desire to upgrade the FPL PV Facility and NASA PV Facility to incorporate new technology that will increase electric power production and/or improve cost effectiveness, the parties may, by mutual agreement, modify the consideration due for any extension in the Lease term.

3.4 Cash Consideration. Provided FPL furnishes satisfactory records of actual and projected costs and expenses for the costs associated with the NASA PV Facility, and provided said records verify that NASA-KSC has received the FMV for the leased Property, there shall be no rent or other cash consideration payable to NASA-KSC for the term of the Phase for which the noncash consideration is provided. If the amounts expended by FPL to provide nonmonetary consideration as defined in this section are less than the FMV as specified, then FPL shall pay in cash to NASA-KSC the difference between the value of the noncash consideration and the FMV of the leased Property. Any cash consideration due shall be made by check payable to NASA-Kennedy Space Center and forwarded to:

National Aeronautics and Space Administration
NASA Shared Services Center (NSSC) – FMD Accounts Receivable
Attn : For the Accounts of Kennedy Space Center
Building 1111, C Road
Stennis Space Center, MS 39529

ARTICLE 4 USE OF LEASED PROPERTY

4.1 Permitted Use. FPL shall use and occupy the leased Property solely for the construction, operation, and maintenance of a photovoltaic power generation facility for generation of electrical power to serve the public utility grid and for lawful purposes incidental thereto (the **"Permitted Use"**), the Permitted Use being subject to, and consistent with the following: (i) the NASA-KSC approved Site Development Plan described in Section 5.2 of the Lease which shall be incorporated into this Lease as Exhibit A-1 for the FPL PV Facility; (ii) the NASA-KSC approved Site Development Plan described in Section 5.2 of the Lease which shall be incorporated into this Lease as Exhibit B-1 for the NASA PV Facility; (iii) the final Environmental Assessment incorporated into this Lease as Exhibit C for the leased Property; (iv) an antenna located

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on approximately one (1) acre of the leased Property that NASA-KSC retains the right to access, operate, and maintain; and (v) all other terms and conditions of this Lease.

4.2 Right of Access. NASA-KSC hereby grants FPL a right of access to the leased Property and to other NASA-KSC property as may be required to perform FPL's obligations pursuant to this Lease, subject to applicable security controls requiring access credentials to be issued by NASA-KSC to FPL personnel and contractors. As a secure Federal facility, NASA-KSC specifically reserves the following rights: (a) to control ingress to and egress from the leased Property, (b) to erect and maintain gates and to regulate or prevent traffic, and (c) restrict access in the event of extraordinary and unpredictable circumstances that could arise from hostile acts, warfare, major accidents, or natural disaster, provided that under such circumstances, access by NASA-badged FPL employees and contractors will be no less than NASA-badged KSC administrative employees. If FPL is restricted from accessing the leased Property due to an event of extraordinary and unpredictable circumstances that could arise from hostile acts, warfare, major accidents, or natural disaster, then FPL's failure to operate and maintain the leased Property during the restricted period shall not be deemed an Event of Default as defined in Section 13.1 of the Lease.

4.3 Right of Entry. NASA-KSC reserves the right to enter the leased Property without prior notification of FPL at any time for reasons it deems in its sole discretion to constitute an emergency requiring immediate response, and at other times for reasons it deems in its sole discretion to be necessary to the protection or administration of its property subject to the prior notification of FPL. Any claim for liability for property damage to, or personal injuries on, the leased Property resulting from NASA-KSC's entry on the leased Property shall be determined pursuant to the Federal Tort Claims Act, 28 U.S.C. 1346, *et seq.*

4.4 Impact from Operations on Other NASA-KSC Land. FPL acknowledges and accepts impacts to its operations at the FPL PV Facility that may arise from KSC land management practices on other NASA-KSC land, such as controlled burning and habitat management performed from time to time by the U.S. Fish and Wildlife Service. In the event that NASA-KSC receives notification that there is to be a controlled burn adjacent to the leased Property, then NASA-KSC shall immediately notify FPL so that the controlled burn can be coordinated with FPL. Any claim for liability for property damage to, or personal injuries on, the leased Property resulting from NASA-KSC's land management practices shall be determined pursuant to the Federal Tort Claims Act, 28 U.S.C. 1346, *et seq.*

ARTICLE 5 SITE DEVELOPMENT

5.1 Environmental Condition Report Furnished to FPL. Prior to the Commencement Date of Phase I, NASA-KSC shall, at its own expense, prepare an Environmental Condition Report ("**ECR**") for the leased Property, to be acknowledged and signed by representatives of NASA-KSC and FPL. The ECR shall set forth those

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environmental conditions and matters affecting the leased Property known as of the Commencement Date as determined from records of the leased Property and the analysis reflected therein.

5.2 Site Development Plan. FPL shall submit for NASA-KSC approval a Site Development Plan for each Phase, as well as for the NASA PV Facility. Each such Site Development Plan shall be consistent with the previously completed Environmental Assessment, addressing any mitigation required therein, and shall show perimeter controls, access points, internal roadways, structures, storm water retention or drainage, and any other site improvements. FPL shall be responsible for ensuring that its contractors construct the FPL PV Facility and the NASA PV Facility in accordance with the NASA-approved Site Development Plans. Each approved Site Development Plan for each Phase of the FPL PV Facility shall be incorporated into this Lease as Exhibit A-1. The approved Site Development Plan for the NASA PV Facility shall be incorporated into this Lease as Exhibit B-1. The Environmental Assessment covering all leased Property is incorporated as Exhibit C.

5.3 Site Development Permits. FPL shall obtain from NASA-KSC excavation permits and/or environmental permits as may be required to perform site development and restoration.

5.4 Land Clearing Waste. All waste resulting from land clearing shall be disposed of off NASA-KSC property or disposed of through the use of appropriate NASA-KSC-approved controlled burning techniques.

ARTICLE 6 DESIGN AND CONSTRUCTION OF FACILITIES

6.1 FPL PV Facility. FPL shall design and construct the FPL PV Facility and the utility grade interconnection systems in compliance with all applicable local, state, and Federal laws and regulations, including Chapter 373, Florida Statutes. FPL will provide to NASA-KSC, for information purposes only, copies of all specifications and design drawings, as well as a complete set of as-built drawings for each Phase of the FPL PV Facility completed.

6.2 NASA PV Facility. FPL shall design and construct the NASA PV Facility and the utility grade interconnection systems in compliance with all applicable local, state, and Federal laws and regulations, including Chapter 373, Florida Statutes. All NASA PV Facility specifications, as well as design drawings at the 45 and 90 percent level of completion shall be submitted to NASA-KSC for approval. NASA-KSC shall be furnished a copy of the final 100 percent design drawings. In the event that NASA-KSC does not approve or disapprove such specifications within five (5) business days after receipt, then the specifications shall be deemed to be approved. In the event that NASA-KSC requires additional equipment or design changes that exceed the requirements or capabilities of the equipment and design installed in the FPL PV Facility, and are not otherwise required to correct a material adverse impact to NASA-KSC property or

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distribution facilities, NASA-KSC will be responsible to provide any engineering, supply, delivery, installation, construction, and testing of such equipment or design. Upon completion of the NASA PV Facility, FPL shall provide to NASA-KSC all final specifications, as well as a complete set of as-built drawings.

6.3 Davis-Bacon Act Compliance. If the scope of work to be performed by FPL for the NASA PV Facility is determined to be subject to the requirements of Davis-Bacon, FPL and its contractor(s) shall comply with all wage determinations and other applicable provisions.

6.4 Warranties. FPL and its contractors shall take all steps necessary to ensure that NASA enjoys the benefits of all manufacturers' warranties of PV system equipment and installation, for any system or portion of system that is constructed for the benefit of NASA, however titled.

6.5 Final Completion. After FPL completes the construction of the NASA PV Facility, it shall notify NASA-KSC in writing of such completion. NASA-KSC shall inspect the NASA PV Facility within ten (10) business days of receiving such notice and give FPL written notice specifying any details of construction or mechanical adjustment which remain to be performed by FPL, and except for the details contained in such written notice from NASA-KSC, all obligations of FPL in regard to the construction of the NASA PV Facility shall be deemed to have been satisfied. With prior notice to NASA-KSC, FPL shall have the right to enter the NASA PV Facility to complete any such unfinished details. Final completion of the NASA PV Facility will be documented in writing by the NASA-KSC Director of Center Operations.

ARTICLE 7 OPERATION, MAINTENANCE, AND REPAIR

7.1 General Requirements. FPL, at its own expense, shall maintain and operate the FPL PV Facility and the NASA PV Facility throughout the term of this Lease. FPL shall perform preventive maintenance in accordance with the manufacturer of the FPL PV Facility and NASA PV Facility recommended maintenance schedule, as well as any greater standards of care and maintenance that may be required for public utility systems. FPL shall perform corrective maintenance or repairs, at its own expense, as required to keep the FPL PV Facility and NASA PV Facility operating at reasonable performance capability. In the event that repairs to the NASA PV Facility are necessary due to fire, natural disaster, or other casualty and such repairs do not arise out of the FPL's maintenance and operation of the NASA PV Facility, then such repairs shall be the responsibility of NASA-KSC.

7.2 Records and Notices. FPL shall maintain records of all preventive and corrective maintenance performed at the NASA PV Facility and shall submit copies of all such records to NASA-KSC on a quarterly basis. If power generation or connection at the NASA PV Facility must be interrupted for any length of time in order to perform preventive or corrective maintenance, FPL will provide notice of such requirement to

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NASA-KSC in accordance with the Spaceport Power Switching Memorandum of Understanding dated September 1, 2003, between NASA-KSC and FPL.

ARTICLE 8 ENVIRONMENTAL COMPLIANCE

8.1 Environmental Definitions. As used in this Lease, "**Hazardous Material**" shall mean any substance that is (a) defined under any Environmental Law (as defined below) as a hazardous substance, hazardous waste, hazardous material, pollutant, or contaminant; (b) a petroleum hydrocarbon, including crude oil or any fraction or mixture thereof; (c) hazardous, toxic, corrosive, flammable, explosive, infectious, radioactive, carcinogenic, or a reproductive toxicant; or (d) otherwise regulated pursuant to any Environmental Law. As used in this Lease, "**Environmental Law**" shall mean all Federal, state, and local laws, statutes, ordinances, regulations, rules, judicial and administrative orders and decrees, permits, licenses, approvals, authorizations, and similar requirements of all Federal, state, and local governmental agencies (including NASA-KSC) or other governmental authorities pertaining to the protection of human health and safety or the environment, now existing or later adopted during the Term. As used in this Lease, "**Lease Activities**" shall mean the lawful activities of FPL that are part of the ordinary course of FPL's business in accordance with the Permitted Use. As used in this Lease, "**Materials**" shall mean the materials handled, used, or stored by FPL in the ordinary course of conducting Lease Activities.

8.2 Environmental Requirements. FPL hereby agrees that (a) FPL shall not conduct, or permit to be conducted, on the leased Property any activity which is not a Lease Activity; (b) FPL shall not use, store or otherwise handle, or permit any use, storage, or other handling of, any Hazardous Material on or about or beneath the leased Property unless it is a material handled, used, or stored by FPL in the ordinary course of conducting Lease Activities; (c) all such materials shall be handled, used, or stored by FPL in accordance with applicable Environmental Law; (d) FPL shall obtain and maintain in effect all permits and licenses required pursuant to any Environmental Law for its Lease Activities and shall at all times comply with all applicable Environmental Laws; (e) FPL shall not engage in the storage, treatment, or disposal on or about or beneath the leased Property of any Hazardous Material except for temporary accumulation of Hazardous Material waste generated in the course of Lease Activities, which accumulation is conducted in accordance with applicable Environmental Law; (f) FPL shall not install any aboveground or underground storage tank or any subsurface lines for the storage or transfer of any Hazardous Material, except for the lawful discharge of waste to sanitary sewer; (g) FPL shall not cause or permit to occur any release of any Hazardous Material or any condition of pollution or nuisance on or about or beneath the leased Property, whether affecting surface water or groundwater, air, the land or the subsurface environment; and (h) if any release of a Hazardous Material to the environment, or any condition of pollution or nuisance, occurs on or about or beneath the leased Property as a result of any act or omission of FPL, its agents, employees, contractors, subcontractors, invitees, or licensees, FPL, at its sole cost and expense, shall promptly undertake all remedial measures required to clean up and abate or otherwise

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respond to the release, pollution, or nuisance in accordance with all applicable Environmental Laws. After notification to FPL, NASA-KSC and its duly appointed representatives shall have the right, but not the obligation, to enter the leased Property at any reasonable time for the purpose of inspecting the storage, use, and handling of any Hazardous Material on the leased Property in order to determine FPL's compliance with the requirements of this Lease and applicable Environmental Laws. If NASA-KSC gives written notice to FPL that FPL's use, storage, or handling of any Hazardous Material on the leased Property may not comply with this Lease or applicable Environmental Law, FPL shall correct any such violation within five (5) calendar days, or such other period to which the parties may mutually agree, after FPL's receipt of such notice from NASA-KSC. The liability of FPL under this section of this Lease shall survive the termination of this Lease with respect to acts or omissions that occur before such termination.

ARTICLE 9 UTILITIES AND MUNICIPAL SERVICES

9.1 Fire and Rescue. NASA-KSC shall provide fire and rescue services for the FPL PV Facility located on the leased Property at the Kennedy Space Center. FPL shall be responsible to install and/or obtain, at its own expense, any other utility or municipal service it may require.

ARTICLE 10 INDEMNIFICATION AND INSURANCE

10.1 Damage or Injury. Except as otherwise provided in this Lease, NASA-KSC shall not be liable to FPL, and FPL hereby waives and releases all claims against NASA-KSC, for any damage to, or loss or theft of, any property or for any bodily or personal injury, illness, or death of any person in, on, or about the leased Property arising at any time and from any cause whatsoever, unless the same is caused solely by the willful misconduct or gross negligence of NASA-KSC. FPL shall indemnify and defend NASA-KSC against and hold NASA-KSC harmless from all claims, demands, liabilities, damages, losses, costs, and expenses, including reasonable attorneys' fees and disbursements, arising from or related to any use or occupancy of the leased Property, or any condition of the leased Property, or any default in the performance of FPL's obligations under this Lease, or any damage to any property (including property of employees and invitees of FPL), or any bodily or personal injury, illness, or death of any person (including employees and invitees of FPL) occurring in, on, or about the leased Property or any part thereof arising at any time and from any cause whatsoever (unless the same is caused solely by the willful misconduct or gross negligence of NASA-KSC) , or occurring in, on, or about any part of the leased Property when such damage, bodily or personal injury, illness, or death is caused by any act or omission of FPL or its agents, employees, contractors, invitees, or licensees. This section of this Lease shall survive the termination of this Lease with respect to any damage, bodily or personal injury, illness, or death occurring prior to such termination.

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10.2 Insurance Coverages and Amounts. FPL acknowledges that any contractors working at the FPL PV Facility and NASA PV Facility shall obtain and keep the following insurance: (a) commercial general liability insurance, including contractual liability, broad form property damage liability, fire legal liability, products and completed operations, and medical payments, with limits not less than two million dollars ($2,000,000) per occurrence and aggregate, insuring against claims for bodily injury, personal injury, and property damage arising from the use, occupancy, or maintenance of the leased Property; (b) business auto liability insurance with limits not less than one million dollars ($1,000,000) per accident covering owned, hired, or non-owned vehicles; (c) workers' compensation insurance for all of its employees in statutory limits as required by Florida law; and (d) employers'liability insurance which affords not less than five hundred thousand dollars ($500,000) for each coverage. FPL, at its option, may maintain all risk property insurance for all personal property, trade fixtures, and equipment of FPL installed by FPL in the leased Property and may obtain business income and extra expense coverage. Any assignees or sublessees under this Lease shall also be required to obtain and keep the foregoing insurance with such coverage amounts. Relating to all insurance coverage for the FPL PV Facility, FPL is self-insured and maintains a comprehensive property and liability insurance program with deductibles of two million dollars ($2,000,000) per occurrence. FPL shall provide NASA-KSC with evidence of such self-insurance prior to the Commencement Date. Relating to commercial general liability insurance coverage for the NASA PV Facility, NASA-KSC self-insures its own risk of loss from appropriations covering those liabilities for which NASA-KSC has waived its sovereign immunity pursuant to 28 U.S.C. 1346 *et seq.* or other applicable statute.

10.3 Insurance Requirements.

(a) Except as otherwise provided herein, all insurance and all renewals thereof shall be issued by companies with a rating of at least "A- VIII" (or its equivalent successor) or better in the current edition of Best's Insurance Reports (or its equivalent successor or, if there is no equivalent successor rating, otherwise acceptable to NASA-KSC) and be licensed to do and doing business in Florida.

(b) Except as otherwise provided herein, each policy shall be endorsed to provide that the policy shall not be canceled or materially altered without thirty (30) days prior written notice to NASA-KSC and shall remain in effect notwithstanding any such cancellation or alteration until such notice shall have been given to NASA-KSC and such period of thirty (30) days shall have expired.

(c) Except as otherwise provided herein, the commercial general liability and any automobile liability insurance shall be endorsed to name NASA-KSC (and any other parties designated by NASA-KSC) as an additional insured, shall be primary and noncontributing with any insurance which may be carried by NASA-KSC, and shall afford coverage for all claims based on any act, omission, event, or condition that occurred or arose (or the onset of which occurred or arose) during the policy period.

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(d) In the event that FPL assigns the Lease or sublets the leased Property, then such assignee or sublessee shall deliver certificates of insurance and endorsements to NASA-KSC at least ten (10) days before the transfer date between FPL and the assignee or the sublessee and at least ten (10) days before expiration of each policy. Such documents shall be delivered to the address for certificate holder set forth below. Each certificate of insurance shall list the certificate holder as follows:

National Aeronautics and Space Administration
John F. Kennedy Space Center
Attn: Office of the Chief Counsel
Mail Code: CC
Kennedy Space Center, FL 32899

(e) If NASA-KSC at any time believes that the limits or extent of coverage or deductibles with respect to any of the insurance required in this Lease are insufficient, NASA-KSC may determine the proper and reasonable limits and extent of coverage and deductibles for such insurance, and such insurance shall thereafter be carried with the limits and extent of coverage and deductibles as so determined until further change pursuant to the provisions of this Lease.

10.4 Subrogation. In the event that FPL assigns the Lease or sublets the leased Property, the assignees or sublessees shall waive, under all policies of insurance now or hereafter carried by the assignees or sublessees insuring or covering the leased Property or any operation thereof, all rights of subrogation which any such insurer may have to any claims of the assignees or sublessees against NASA-KSC. Assignees or sublessees shall procure from each of the insurers under all such policies of insurance a waiver of all rights of subrogation which the insurer might otherwise, if at all, have to any claims of assignees or sublessees against NASA-KSC by obtaining from the insurer the following statement: "The insurer waives any right of subrogation against the United States of America which might arise by reason of any payment made under this policy."

ARTICLE 11 RESTORATION OF THE PROPERTY

11.1 General Requirements. On or before the expiration of this Lease, or upon its earlier termination pursuant to this Lease, all buildings, fixtures, equipment, and any other improvements made by FPL to the leased Property, whether temporary or permanent in character, shall be removed and properly disposed of by FPL, and FPL shall restore the leased Property to a cleared, graded condition or to a condition satisfactory to NASA-KSC within a reasonable time. Should FPL fail or neglect to remove said property and restore the leased Property within a reasonable time, then at the option of NASA-KSC, the buildings, fixtures, equipment, and any other improvements made by FPL on the leased Property shall either become the property of the United States without compensation to FPL therefore, or NASA-KSC may cause the buildings, fixtures, equipment, and other improvements made by FPL to be removed at the expense of FPL, and FPL shall have no claim for damages against the United States, its officers, or agents

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on account of such removal and restoration work. FPL shall pay the United States within thirty (30) days after receiving a copy of any written invoices any reasonable sum which may be expended by NASA-KSC in accomplishing the restoration of the leased Property pursuant to this section of this Lease.

11.2 Environmental Condition Report Furnished to NASA-KSC. Upon completion of the restoration of the leased Property pursuant to this section, FPL shall prepare, at its own expense, and submit to NASA-KSC an updated ECR, to be acknowledged and signed by representatives of NASA-KSC and FPL. The ECR shall set forth those environmental conditions and matters affecting the leased Property known as of the restoration date, based on all known activities that have occurred at the leased Property as well as information contained in the records of the leased Property and the analysis reflected therein. FPL shall not be obligated to remedy any environmental conditions and matters affecting the leased Property that are not a result of FPL's Lease Activities on the leased Property.

ARTICLE 12 ASSIGNMENT OR SUBLEASE

12.1 Prohibition. Except as otherwise provided herein, FPL shall not, directly or indirectly, without the prior written consent of NASA-KSC (which consent may be not be arbitrarily withheld), assign this Lease or any interest herein, or sublease the leased Property or any part thereof, or permit the use or occupancy of the leased Property by any person or entity other than FPL. FPL shall not, directly or indirectly, without the prior written consent of NASA-KSC (which consent may not be arbitrarily withheld), pledge, mortgage, or hypothecate this Lease or any interest herein. This Lease shall not, nor shall any interest herein, be assignable as to the interest of FPL involuntarily or by operation of law without the prior written consent of NASA-KSC (which consent may not be arbitrarily withheld or delayed). FPL agrees that the instrument by which any assignment or sublease through which NASA-KSC's consent is accomplished shall expressly provide that the assignee or sublessee will perform all of the covenants to be performed by FPL under this Lease (in the case of a sublease, only insofar as such covenants relate to the portion of the leased Property subject to such sublease) as and when performance is due after the effective date of the assignment or sublease and that NASA-KSC will have the right to enforce such covenants directly against such assignee or sublessee. Any purported assignment or sublease without an instrument containing the foregoing provisions shall be void. FPL shall be permitted to assign the Lease or sublet all or any portion of the leased Property without the prior written consent of NASA-KSC if the assignee or sublessee's interest in the Lease arises out of the transfer of any of the following: (1) all of FPL's assets; (2) the transfer of FPL's assets incident to a merger or corporate consolidation; or (3) a stock purchase by FPL or of FPL by an assignee or sublessee.

12.2 NASA-KSC's Consent or Termination. Except as otherwise provided herein, if FPL wishes to assign this Lease or sublease all or any part of the leased Property, FPL shall give written notice to NASA-KSC identifying the intended assignee

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or sublessee by name and address and specifying all of the terms of the intended assignment or sublease. FPL shall give NASA-KSC such additional information concerning the intended assignee or sublessee (including complete financial statements and a business history) or the intended assignment or sublease (including true copies thereof) as NASA-KSC requests. Except as otherwise provided herein, for a period of thirty (30) days after such written notice is given by FPL, NASA-KSC shall have the right, by giving written notice to FPL, to consent in writing to the intended assignment or sublease, unless NASA-KSC determines not to consent.

12.3 Completion. If NASA-KSC consents in writing, FPL may complete the intended assignment or sublease subject to the following covenants: (a) the assignment or sublease shall be on the same terms as set forth in the written notice given by FPL to NASA-KSC, (b) no assignment or sublease shall be valid and no assignee or sublessee shall take possession of the leased Property or any part thereof until an executed duplicate original of such assignment or sublease has been delivered to NASA-KSC, and (c) all "excess rent" (as defined below) derived from such assignment or sublease shall be paid to NASA-KSC. Such excess rent shall be deemed to be, and shall be paid by FPL to NASA-KSC as, additional rent. FPL shall pay such excess rent to NASA-KSC immediately as and when such excess rent becomes due and payable to FPL. As used in this section of this Lease, "**excess rent**" shall mean the amount by which the total money and other economic consideration to be paid by the assignee or sublessee as a result of an assignment or sublease, whether denominated rent or otherwise, exceeds, in the aggregate, the total amount of rent which FPL is obligated to pay to NASA-KSC under this Lease (prorated to reflect the rent allocable to the portion of the Property subject to such assignment or sublease), less only the reasonable costs paid by FPL for additional improvements installed in the portion of the Property subject to such assignment or sublease by FPL at FPL's sole cost and expense for the specific assignee or sublessee in question, without deduction for carrying costs due to vacancy or otherwise. Such costs of additional improvements shall be amortized without interest over the term of such assignment or sublease.

12.4 FPL Not Released. Except as otherwise provided herein, no assignment or sublease shall release FPL from FPL's obligations and liabilities under this Lease or alter the primary liability of FPL to pay all rent and to perform all obligations to be paid and performed by FPL. In the event that an assignee has a net worth in excess of fifty million dollars ($50,000,000), then FPL shall be released from any obligations and liability under the Lease as of the date of such assignment. No assignment or sublease shall amend or modify this Lease in any respect, and every assignment and sublease shall be subject and subordinate to this Lease. The acceptance of rent by NASA-KSC from any other person or entity shall not be deemed to be a waiver by NASA-KSC of any provision of this Lease. Consent to one assignment or sublease shall not be deemed consent to any subsequent assignment or sublease. FPL shall pay to NASA-KSC all direct costs and shall reimburse NASA-KSC for all expenses incurred by NASA-KSC in connection with any assignment or sublease requested by FPL which shall not exceed five hundred dollars ($500). Except as otherwise provided herein, if any assignee, sublessee, or successor of FPL defaults in the performance of any obligation to be performed by FPL under this

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Lease, NASA-KSC may proceed directly against FPL without the necessity of exhausting remedies against such assignee, sublessee, or successor.

ARTICLE 13 EVENTS OF DEFAULT AND REMEDIES

13.1 Default by FPL. The occurrence of any one or more of the following events ("**Event of Default**") shall constitute a breach of this Lease by FPL:

(a) FPL fails to provide the consideration required under this Lease, or other amount of money or charge payable by FPL, and such failure continues for more than sixty (60) days after written notice from NASA-KSC that such consideration becomes due or payable; or

(b) FPL fails to perform or breaches any other agreement or covenant of this Lease to be performed or observed by FPL as and when performance or observance is due, and such failure or breach continues for more than thirty (30) days after NASA-KSC gives written notice thereof to FPL; provided, however, that if, by the nature of such agreement or covenant, such failure or breach cannot reasonably be cured within such period of thirty (30) days, an Event of Default shall not exist as long as FPL commences with due diligence and dispatch the curing of such failure or breach within such period of thirty (30) days and, having so commenced, thereafter prosecutes with diligence and dispatch and completes the curing of such failure or breach; or

(c) FPL (i) files, or consents by answer or otherwise to the filing against it of, a petition for relief or reorganization or arrangement or any other petition in bankruptcy or for liquidation or to take advantage of any bankruptcy, insolvency, or other debtors' relief law of any jurisdiction, (ii) makes an assignment for the benefit of its creditors, or (iii) consents to the appointment of a custodian, receiver, trustee, or other officer with similar powers of FPL or of any substantial part of FPL's property; or

(d) Without consent by FPL, a court or government authority enters an order, and such order is not vacated within thirty (30) days, (i) appointing a custodian, receiver, trustee, or other officer with similar powers with respect to FPL or with respect to any substantial part of FPL's property, or (ii) constituting an order for relief or approving a petition for relief or reorganization or arrangement or any other petition in bankruptcy or for liquidation or to take advantage of any bankruptcy, insolvency, or other debtors' relief law of any jurisdiction, or (iii) ordering the dissolution, winding-up, or liquidation of FPL; or

(e) This Lease or any estate of FPL hereunder is levied upon under any attachment or execution and such attachment or execution is not vacated within thirty (30) days; or

(f) FPL abandons the Property.

HEARING EXHIBIT - 00000582

13.2 Termination. If an Event of Default occurs, NASA-KSC shall have the right at any time to give a written termination notice to FPL, and on the date specified in such notice, FPL's right to possession shall terminate and this Lease shall terminate. Upon such termination, NASA-KSC shall have the full and immediate right to possession of the leased Property and NASA-KSC shall have the right to recover from FPL all amounts of money or charges otherwise due under this Lease, including but not limited to amounts due for restoration of the leased Property. Termination under this Article shall create no liability on the part of NASA-KSC for FPL's capital costs of construction, maintenance, operation, upgrade, or removal of facilities, and such costs shall not be recoverable from NASA-KSC.

13.3 Continuation. If an Event of Default occurs, this Lease shall continue in effect for so long as NASA-KSC does not terminate FPL's right to possession, and NASA-KSC shall have the right to enforce all its rights and remedies under this Lease, including the right to recover the consideration due under this Lease. Acts of maintenance or preservation or efforts to relet the leased Property or the appointment of a receiver upon initiative of NASA-KSC to protect NASA-KSC's interest under this Lease shall not constitute a termination of FPL's right to possession unless written notice of termination is given by NASA-KSC to FPL.

13.4 Remedies Cumulative. Subject to Section 15.5, upon the occurrence of an Event of Default, NASA-KSC shall have the right to exercise and enforce all rights and remedies granted or permitted by law. The remedies provided for in this Lease are cumulative and in addition to all other remedies available to NASA-KSC at law or in equity by statute or otherwise. Exercise by NASA-KSC of any remedy shall not be deemed to be an acceptance of surrender of the leased Property by FPL, either by agreement or by operation of law.

13.5 FPL's Primary Duty. All agreements and covenants to be performed or observed by FPL under this Lease shall be at FPL's sole cost and expense and without any abatement of rent. If FPL fails to pay any sum of money to be paid by FPL or to perform any other act to be performed by FPL under this Lease, NASA-KSC shall have the right, but shall not be obligated, and without waiving or releasing FPL from any obligations of FPL, to make any such payment or to perform any such other act on behalf of FPL in accordance with this Lease. All sums so paid by NASA-KSC and all costs incurred or paid by NASA-KSC shall be deemed additional rent hereunder and FPL shall pay the same to NASA-KSC within thirty (30) days after receipt of written invoices, together with interest on all such sums and costs from the date of expenditure by NASA-KSC to the date of repayment by FPL at the rate of 10 percent per annum.

13.6 Abandoned Property. If FPL abandons the leased Property, or is dispossessed by process of law or otherwise, all alterations, additions, fixtures, and improvements made by FPL and left in the leased Property, and all buildings, fixtures, equipment, and other improvements belonging to FPL and left at the leased Property, shall be deemed to be abandoned. NASA-KSC may retain the same, or at the option of

HEARING EXHIBIT - 00000583

NASA-KSC, sell or otherwise dispose of the same in any commercially reasonable manner.

13.7 Default by NASA-KSC. If NASA-KSC defaults under this Lease, FPL shall give written notice to NASA-KSC specifying such default with particularity, and NASA-KSC shall have sixty (60) days after receipt of such notice within which to cure such default. In the event of any default by NASA-KSC, FPL's exclusive remedy shall be an action for damages against NASA-KSC as an agency of the United States.

ARTICLE 14 NOTICES

14.1 Method. Except as otherwise specifically provided in this Lease, all requests, approvals, consents, notices, and other communications under this Lease shall be properly given only if made in writing and either deposited in the United States mail, postage prepaid and certified with return receipt requested, or delivered by hand (which may be through a messenger or recognized delivery, courier, or air express service), or sent via facsimile or electronic mail, and addressed to the applicable party as specified in this Lease below (or such other personnel or place as a party may from time to time designate in a written notice to the other party). Such requests, approvals, consents, notices, and other communications shall be effective on the date of receipt (evidenced by the certified mail receipt) if delivered by United States mail; of hand delivery if hand delivered; or of transmission as evidenced by a machine-generated receipt or proof of transmission if sent via facsimile or electronic mail. If any such request, approval, consent, notice, or other communication is not received or cannot be delivered due to a change in the address of the receiving party, of which notice was not previously given to the sending party, or due to a refusal to accept by the receiving party, such request, approval, consent, notice, or other communication shall be effective on the date delivery is attempted. Any request, approval, consent, notice, or other communication under this Lease may be given on behalf of a party by the attorney for such party.

NASA-KSC:
James E. Ball
Center Development Manager
John F. Kennedy Space Center, NASA
Mail Code: TA-E
Kennedy Space Center, FL 32899
321-867-2998 (voice)
321-861-9191 (fax)
E-mail: <James.E.Ball@nasa.gov>

FPL:
Kathryn S. Salvador
Florida Power & Light Company
700 Universe Blvd., EX1/JB
Juno Beach, FL 33408
561-691-7054 (voice)
561-304-5233 (fax)
<E-mail: Kathy_salvador@fpl.com>

HEARING EXHIBIT - 00000584

14.2 Close Calls and Mishaps.

(a) For purposes of this Lease, the following terms shall have the following meanings: (i) "**Close Call**" shall mean an occurrence or a condition of employee concern in which there is no injury, or only minor injury requiring first aid, or damage to property or equipment of less than one thousand dollars ($1000), but which possesses a potential to cause a Mishap (as defined below); and (ii) "**Mishap**" shall mean an unplanned event on or about the leased Property and arising from the acts or omissions of FPL or its employees, agents, contractors, or invitees that results in at least one of the following: (1) injury to any person; (2) damage to public or private property (including foreign property); (3) occupational injury or occupational illness to any person; or (4) failure of a NASA mission. FPL shall report all Close Calls or Mishaps to NASA-KSC by telephoning the NASA-KSC Safety and Mission Assurance Directorate at 321-867-7911 (321-867-SAFE). If emergency response is required due to an injury, fire, release of hazardous materials or serious damage, call 911 (321-867-7911 from a cell phone).

(b) In addition, if a Mishap involves the death of an employee, or the hospitalization for inpatient care of three or more employees, then as soon as possible after the Mishap but in no event more than eight hours after FPL has knowledge of any such Mishap, FPL shall notify both the Occupational Safety and Health Administration ("**OSHA**") by telephoning the area office nearest the site of the Mishap or OSHA's toll-free number, 800–321–6742, and the NASA-KSC Safety and Mission Assurance Directorate at 321-867-7911 (321-867-SAFE).

(c) NASA-KSC reserves the right, to be exercised in its sole discretion, to investigate any Mishap in accordance with NASA-KSC's policies and procedures. FPL shall cooperate in any such investigation. If FPL conducts an independent Mishap investigation, FPL shall provide KSC with a copy of the final Mishap report.

ARTICLE 15 MISCELLANEOUS

15.1 General. The words "NASA-KSC" and "FPL" as used herein shall include the plural as well as the singular. If there is more than one FPL, the obligations hereunder imposed upon FPL shall be joint and several. Time is of the essence of this Lease and each and all of its provisions. This Lease shall benefit and bind NASA-KSC and FPL and the permitted personal representatives, heirs, successors, and assigns of NASA-KSC and FPL. If any provision of this Lease is determined to be illegal or unenforceable, such determination shall not affect any other provision of this Lease, and all such other provisions shall remain in full force and effect. FPL shall not record this Lease or any memorandum or short form of it.

15.2 No Waiver. The waiver by NASA-KSC or FPL of any breach of any covenant in this Lease shall not be deemed to be a waiver of any subsequent breach of the same or any other covenant in this Lease, nor shall any custom or practice which may

HEARING EXHIBIT - 00000585

grow up between NASA-KSC and FPL in the administration of this Lease be construed to waive or to lessen the right of NASA-KSC or FPL to insist upon the performance by NASA-KSC or FPL in strict accordance with this Lease. The subsequent acceptance of rent hereunder by NASA-KSC or the payment of rent by FPL shall not waive any preceding breach by FPL of any covenant in this Lease, nor cure any Event of Default, nor waive any forfeiture of this Lease or unlawful detainer action.

15.3 Exhibits. The exhibits referred to in this Lease are hereby incorporated and made a part of this Lease.

15.4 Broker(s). FPL warrants and represents to NASA-KSC that FPL has negotiated this Lease directly with NASA-KSC and has not authorized or employed, or acted by implication to authorize or to employ, any other real estate broker to act for FPL in connection with this Lease.

15.5 Damages. NASA-KSC and FPL each hereby expressly, irrevocably, fully, and forever releases, waives, and relinquishes any and all right to receive punitive, exemplary, and consequential damages from the other (or any past, present, or future member, trustee, director, officer, employee, agent, representative, or advisor of the other) in any claim, demand, action, suit, proceeding, or cause of action in which NASA-KSC and FPL are parties, which in any way (directly or indirectly) arises out of, results from, or relates to, any of the following, in each case whether now existing or hereafter arising and whether based on contract or tort or any other legal basis: This Lease; any past, present, or future act, omission, conduct, or activity with respect to this Lease; any transaction, event or occurrence contemplated by this Lease; the performance of any obligation or the exercise of any right under this Lease; or the enforcement of this Lease. NASA-KSC and FPL reserve the right to recover actual damages, with interest, attorneys' fees, costs, and expenses as provided in this Lease, for any breach of this Lease.

15.6 Entire Agreement. There are no oral agreements between NASA-KSC and FPL affecting this Lease, and this Lease supersedes and cancels any and all previous negotiations, arrangements, brochures, offers, agreements, and understandings, oral or written, if any, between NASA-KSC and FPL or displayed by NASA-KSC to FPL with respect to the subject matter of this Lease, the leased Property. There are no commitments, representations, or assurances between NASA-KSC and FPL or between any real estate broker and FPL other than those expressly set forth in this Lease, and all reliance with respect to any commitments, representations, or assurances is solely upon commitments, representations, and assurances expressly set forth in this Lease. This Lease may not be amended or modified in any respect whatsoever except by an agreement in writing signed by NASA-KSC and FPL.

15.7 Governing Law. NASA-KSC and FPL agree to first attempt to settle any dispute arising out of or in connection with this Lease by good-faith negotiation. If the parties are unable to resolve amicably any dispute arising out of or in connection with this Lease, each shall have all remedies available at law or in equity. U.S. Federal law

HEARING EXHIBIT - 00000586

governs this Lease for all purposes, including, but not limited to, determining the validity of this Lease, the meaning of its provisions, and the rights, obligations and remedies of the Parties. NASA-KSC and FPL consent and agree that any legal proceeding involving this Lease, or the activities conducted under this Lease, which involves the United States, NASA-KSC, its Administrator, or any of its officials or employees, shall be brought in an Administrative Court or Federal Court of competent jurisdiction. FPL shall, at its sole cost and expense, promptly comply with all applicable Federal, state, and local laws.

15.8 Taxes and Assessments. FPL shall pay, to the applicable taxing authority upon written demand and prior to delinquency, all taxes, assessments, excises, levies, fees, and charges, including all payments related to the cost of providing facilities or services, of every kind and description, general or special, ordinary or extraordinary, foreseen or unforeseen, secured or unsecured, whether or not now customary or within the contemplation of NASA-KSC and FPL (collectively "**Taxes**"), that are levied, assessed, charged, confirmed, or imposed by any public or government authority upon or against, or measured by, or reasonably attributable to, the leased Property or any part thereof or any improvements constructed upon. FPL may contest the legal validity or amount of any Taxes for which it is responsible under this Lease, and may institute such proceedings as it considers necessary to recover or reduce its Taxes, provided that FPL shall bear all expenses in pursuing such contest or proceeding. FPL shall not pay any Taxes that are attributable to the NASA PV Facility.

15.9 Anti-Deficiency Act. NASA-KSC's ability to perform its obligations under this Lease is subject to the availability of appropriated funds. Nothing in this Lease commits the United States Congress to appropriate funds for the purposes stated herein (pursuant to the Anti-Deficiency Act, 31 U.S.C. §1341).

15.10 Authority. NASA-KSC is the sole owner of the leased Property and has the unrestricted right and authority to sign this Lease and to grant FPL the rights granted in this Lease. There are no mortgages encumbering the leased Property

15.11 Successors and Assigns. The terms and provisions of this Lease shall run with the land and be binding on and inure to the benefit of the heirs, successors, assigns and personal representatives of the Parties. NASA-KSC agrees to promptly notify FPL upon the transfer of any interest in the leased Property.

15.12 Quiet Enjoyment. FPL may peaceably and quietly have, hold, and enjoy the leased Property during the Term, and except as otherwise provided in this Lease, NASA-KSC shall take no action regarding the leased Property that will interfere with the Permitted Use.

HEARING EXHIBIT - 00000587

IN WITNESS WHEREOF, NASA-KSC and FPL have executed this Lease as of the latter date set forth below:

FPL:
Florida Power and Light Company,
A Florida Corporation

By: _____
Eric E. Silagy,
Vice President of Development

Date: June 25, 2008

NASA-KSC:
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION,
an Agency of the United States

By _____
W. W. Parsons
Director, John F. Kennedy Space Center

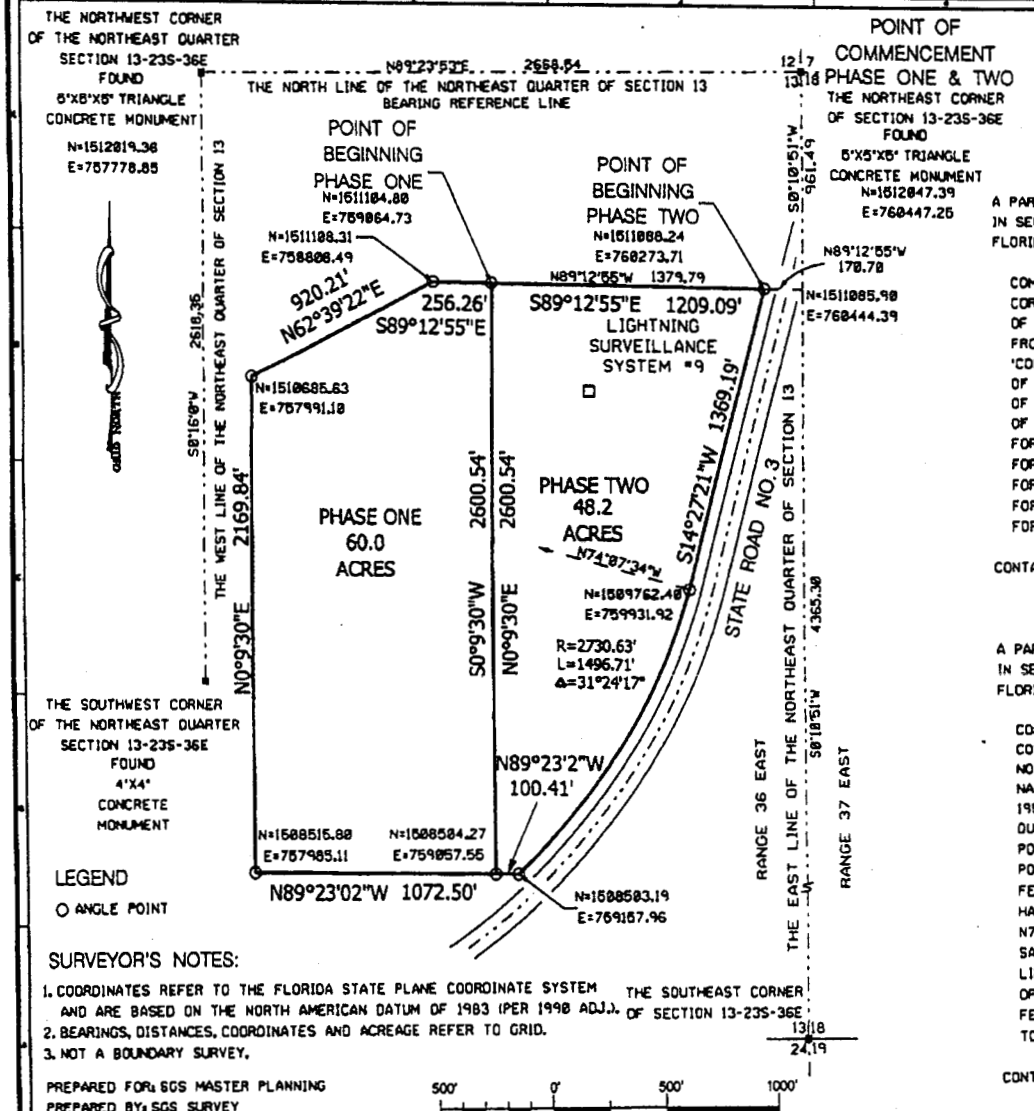
Date: 6/24/08

HEARING EXHIBIT - 00000588

EXHIBIT A

Legal Description of the FPL PV Facilities

HEARING EXHIBIT - 00000589



SKETCH OF DESCRIPTION
F.P.L. SOLAR PHOTOVOLTAIC

PHASE ONE

A PARCEL OF LAND LYING ON THE JOHN F. KENNEDY SPACE CENTER, IN SECTION 13, TOWNSHIP 23 SOUTH, RANGE 36 EAST, BREVARD COUNTY, FLORIDA, AND BEING MORE FULLY DESCRIBED AS FOLLOWS:

COMMENCE AT THE NORTHEAST CORNER OF SECTION 13, SAID CORNER HAVING A FLORIDA STATE PLANE COORDINATE VALUE OF NORTH 1512847.39 AND EAST 760447.25 (NAD83), AS DERIVED FROM A NATIONAL GEODETIC SURVEY TRIANGULATION STATION 'COURTENAY 1953'; THENCE S00°10'51"W ALONG THE EAST LINE OF THE NORTHEAST QUARTER OF SAID SECTION 13 FOR A DISTANCE OF 961.49 FEET TO A POINT; THENCE N89°12'55"W FOR A DISTANCE OF 1379.79 FEET TO THE POINT OF BEGINNING; THENCE S0°9'30"W FOR A DISTANCE OF 2600.54 FEET TO A POINT; THENCE N89°23'02" W FOR A DISTANCE OF 1072.50 FEET TO A POINT; THENCE N0°9'30" E FOR A DISTANCE OF 2169.84 FEET TO A POINT; THENCE N62°39'22" E FOR A DISTANCE OF 920.21 FEET TO A POINT; THENCE S89°12'55" E FOR A DISTANCE OF 256.26 FEET TO THE POINT OF BEGINNING.

CONTAINING 60.8 ACRES MORE OR LESS.

PHASE TWO

A PARCEL OF LAND LYING ON THE JOHN F. KENNEDY SPACE CENTER, IN SECTION 13, TOWNSHIP 23 SOUTH, RANGE 36 EAST, BREVARD COUNTY, FLORIDA, AND BEING MORE FULLY DESCRIBED AS FOLLOWS:

COMMENCE AT THE NORTHEAST CORNER OF SECTION 13, SAID CORNER HAVING A FLORIDA STATE PLANE COORDINATE VALUE OF NORTH 1512847.39 AND EAST 760447.25 (NAD83), AS DERIVED FROM NATIONAL GEODETIC SURVEY TRIANGULATION STATION 'COURTENAY 1953'; THENCE S00°10'51"W ALONG THE EAST LINE OF THE NORTHEAST QUARTER OF SAID SECTION 13 FOR A DISTANCE OF 961.49 FEET TO A POINT; THENCE N89°12'55"W FOR A DISTANCE OF 178.78 FEET TO THE POINT OF BEGINNING; THENCE S14°27'21"W FOR A DISTANCE OF 1369.19 FEET TO THE BEGINNING OF A CURVE CONCAVE TO THE NORTHWEST HAVING A RADIUS OF 2730.63 FEET AND TO WHICH A RADIAL LINE BEARS N74°07'34"W; THENCE SOUTHWESTERLY 1496.71 FEET ALONG THE ARC OF SAID CURVE THROUGH A CENTRAL ANGLE OF 31°24'17" TO A NON-TANGENT LINE; THENCE N89°23'02"W ALONG SAID NON-TANGENT LINE FOR A DISTANCE OF 100.41 FEET TO A POINT; THENCE N0°9'30" E FOR A DISTANCE OF 2600.54 FEET TO A POINT; THENCE S89°12'55"E FOR A DISTANCE OF 1209.09 FEET TO THE POINT OF BEGINNING.

CONTAINING 48.2 ACRES MORE OR LESS.

SGS SPACE GATEWAY SUPPORT

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION JOHN F. KENNEDY SPACE CENTER, NASA KENNEDY SPACE CENTER, FLORIDA

F.P.L SOLAR PHOTOVOLTAIC LAND DESCRIPTION

NAME	SIGNATURE	DATE
DRN		
CHK		8-13-04

LEGAL DESCRIPTION

HEARING EXHIBIT - 00000590

EXHIBIT A-1

Site Development Plan of the FPL PV Facilities

HEARING EXHIBIT - 00000591

(FPL site layout plan here)

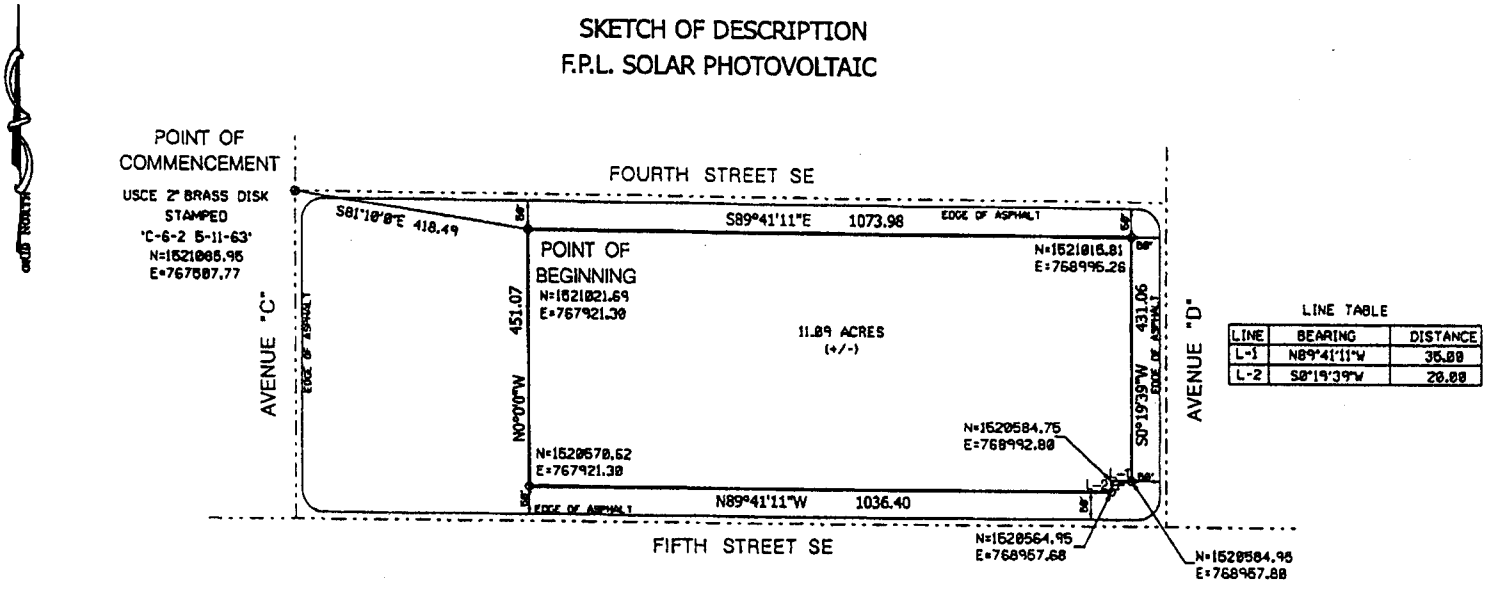
HEARING EXHIBIT - 00000592

EXHIBIT B

Legal Description of the NASA PV Facility

HEARING EXHIBIT - 00000593

SKETCH OF DESCRIPTION
F.P.L. SOLAR PHOTOVOLTAIC



LINE TABLE

LINE	BEARING	DISTANCE
L-1	N89°41'11"W	35.00
L-2	S0°19'39"W	20.00

LEGAL DESCRIPTION

A PARCEL OF LAND LYING ON THE JOHN F. KENNEDY SPACE CENTER, IN SECTION 5, TOWNSHIP 23 SOUTH, RANGE 37 EAST, BREVARD COUNTY, FLORIDA, AND BEING MORE FULLY DESCRIBED AS FOLLOWS:

COMMENCE AT AN ARMY CORP OF ENGINEERS 2" BRASS DISK STAMPED USCE C-6-2 5-11-63 SET IN THE CENTER LINE INTERSECTION OF "C" AVENUE WITH FOURTH STREET SE, SAID DISK HAVING A FLORIDA STATE PLANE COORDINATE VALUE OF NORTH 1521085.95 AND EAST 767587.77 (NAD83), AS DERIVED FROM NATIONAL GEODETIC SURVEY TRIANGULATION STATION 'COURTENAY 1953'; THENCE SOUTH 81°18'08" EAST FOR A DISTANCE OF 418.49 FEET TO THE POINT OF BEGINNING; THENCE SOUTH 89°41'11" EAST FOR A DISTANCE OF 1073.98 FEET; THENCE SOUTH 00°19'39" WEST FOR A DISTANCE OF 431.06 FEET; THENCE NORTH 89°41'11" WEST FOR A DISTANCE OF 35.00 FEET; THENCE SOUTH 00°19'39" WEST FOR A DISTANCE OF 20.00 FEET; THENCE NORTH 89°41'11" WEST FOR A DISTANCE OF 1036.40 FEET; THENCE NORTH 00°00'00" WEST FOR A DISTANCE OF 451.07 FEET TO THE POINT OF BEGINNING.

CONTAINING 11.89 ACRES MORE OR LESS.

SURVEYOR'S NOTES:

1. COORDINATES REFER TO THE FLORIDA STATE PLANE COORDINATE SYSTEM AND ARE BASED ON THE NORTH AMERICAN DATUM OF 1983 (PER 1990 ADJ.).
2. BEARINGS, DISTANCES, COORDINATES AND ACREAGE REFER TO GRID.
3. NOT A BOUNDARY SURVEY.

LEGEND

o ANGLE POINT

PREPARED FOR: SGS MASTER PLANNING
PREPARED BY: SGS SURVEY

200' 0' 200' 400'
1" = 200'

SGS
SPACE GATEWAY SUPPORT
SURVEY SERVICES
KENNEDY SPACE CENTER, FLORIDA

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
JOHN F. KENNEDY SPACE CENTER, NASA
KENNEDY SPACE CENTER, FLORIDA

F.P.L. SOLAR PHOTOVOLTAIC
LAND DESCRIPTION

LEGAL DESCRIPTION

HEARING EXHIBIT - 00000594

HOLDING PAGE FOR EXHIBIT B-1

Site Development Plan of the NASA PV Facility

HEARING EXHIBIT - 00000595

EXHIBIT C

Environmental Assessment of the Leased Property

HEARING EXHIBIT - 00000596

EXHIBIT D

Typical Expenses for Installation, Maintenance, and Operation of a Photovoltaic Power Generation Facility

Typical Expenses for Installation of PV Facilities:

(1) PV modules
(2) Mounting system
(3) Cabling system
(4) Inverters
(5) Combiners
(6) Fuse boxes
(7) Transformers
(8) Security light
(9) Monitoring and communication hardware
(10) Weather station hardware
(11) Perimeter fence and gate
(12) Landscaping

Typical Expenses for Maintenance and Operation of PV Facilities

(1) PV module cleaning
(2) Perimeter fence and gate maintenance on an as needed basis.
(3) Landscape maintenance within the plant perimeter fencing.
(4) Remote monitoring of PV Facilities from FPL's Juno Beach facility.
(5) Account management to address reporting requirements.
(6) Planned routine preventive maintenance of PV Facilities
(7) Management of spare parts
(8) Response and restoration of unplanned events.
(9) Contract coordination to manage any expenses for maintenance and operation.

The work provided by FPL will consist of activities necessary to install, operate and maintain the NASA PV Facility in a safe, reliable, cost effective and environmentally responsible manner.

HEARING EXHIBIT - 00000597

EXHIBIT E

PHASE 1 Assumptions	
Agreed upon appraised value per acre of land	$ 75,000
Total acres	60
Agreed upon lease fee - as % of value	10%
Agreed upon annual escalation factor for lease payment	2.5%
Agreed upon length (years) of lease	30
FPL Weighted Cost of Capital (PSC approved Discount Rate for Capital Projects)	8.35%

Contract Year	Lease Payment	Escalation Rate	Escalated Payment	NPV	Subtotal
1	450,000		$ 450,000	450,000	450,000
2	450,000	2.5%	461,250	425,710	875,710
3	450,000	2.5%	472,781	402,731	1,278,441
4	450,000	2.5%	484,601	380,993	1,659,434
5	450,000	2.5%	496,716	360,428	2,019,862
6	450,000	2.5%	509,134	340,973	2,360,834
7	450,000	2.5%	521,862	322,568	2,683,402
8	450,000	2.5%	534,909	305,156	2,988,558
9	450,000	2.5%	548,281	288,685	3,277,243
10	450,000	2.5%	561,988	273,102	3,550,345
11	450,000	2.5%	576,038	258,361	3,808,706
12	450,000	2.5%	590,439	244,415	4,053,121
13	450,000	2.5%	605,200	231,222	4,284,343
14	450,000	2.5%	620,330	218,741	4,503,084
15	450,000	2.5%	635,838	206,934	4,710,019
16	450,000	2.5%	651,734	195,764	4,905,783
17	450,000	2.5%	668,028	185,197	5,090,980
18	450,000	2.5%	684,728	175,201	5,266,181
19	450,000	2.5%	701,846	165,744	5,431,925
20	450,000	2.5%	719,393	156,798	5,588,723
21	450,000	2.5%	737,377	148,334	5,737,057
22	450,000	2.5%	755,812	140,327	5,877,384
23	450,000	2.5%	774,707	132,753	6,010,137
24	450,000	2.5%	794,075	125,587	6,135,724
25	450,000	2.5%	813,927	118,808	6,254,532
26	450,000	2.5%	834,275	112,395	6,366,927
27	450,000	2.5%	855,132	106,328	6,473,255
28	450,000	2.5%	876,510	100,589	6,573,844
29	450,000	2.5%	898,423	95,159	6,669,004
30	450,000	2.5%	920,883	90,023	6,759,027
31	450,000	2.5%	943,905	85,164	6,844,190
32	450,000	2.5%	967,503	80,567	6,924,757
33	450,000	2.5%	991,691	76,218	7,000,975
34	450,000	2.5%	1,016,483	72,104	7,073,079
35	450,000	2.5%	1,041,895	68,212	7,141,291
36	450,000	2.5%	1,067,942	64,530	7,205,821
37	450,000	2.5%	1,094,641	61,047	7,266,868
38	450,000	2.5%	1,122,007	57,752	7,324,619
39	450,000	2.5%	1,150,057	54,634	7,379,254
40	450,000	2.5%	1,178,809	51,685	7,430,939
41	450,000	2.5%	1,208,279	48,895	7,479,834
42	450,000	2.5%	1,238,486	46,256	7,526,091
43	450,000	2.5%	1,269,448	43,759	7,569,850
44	450,000	2.5%	1,301,184	41,397	7,611,247
45	450,000	2.5%	1,333,714	39,163	7,650,410
46	450,000	2.5%	1,367,056	37,049	7,687,459
47	450,000	2.5%	1,401,233	35,049	7,722,508
48	450,000	2.5%	1,436,264	33,157	7,755,666
49	450,000	2.5%	1,472,170	31,367	7,787,033
50	450,000	2.5%	1,508,975	29,674	7,816,707

Note: This exhibit represents the escalated and present value of rental payments for Phase I land based on the highlighted assumptions above. It assumes that Phase I begins in August of 2008 and price escalation occurs at the beginning of each contract year. The present value of the rental payments for Phase II will be based on this same calculation, with the exception that the assumptions can change based on mutual acceptance by both parties. The Subtotal in Contract Year 30 includes 30 years of operation, maintenance and capital replacement costs with a value of $1,200,000, the net present value of which is $400,000. The remaining $6,359,027 represents installed capital costs of the NASA PV Facility.

9

FPL's response to Staff's First Set of Interrogatories (Nos. 1 – 15)

Q.

Section 4 of FPL's petition indicates that the Utility Water Act Group (UWAG), of which FPL is a member, has petitioned for a writ of certiorari seeking to have the Supreme Court review the Second Circuit's ruling. Section 6 of the petition indicates that FPL is going to take two actions to help limit the compliance cost impact of potential revisions to the Phase II Rule on FPL and its customers. Based upon FPL's knowledge and best understanding, please explain:

a) What would be the chance of success in getting the writ of certiorari;

b) What would be the chance of success in receiving a favorable ruling from the Supreme Court;

c) What would be the chance of success for FPL's actions proposed in Section 6?

A.

a) On April 11, 2008, the Supreme Court has granted *certiorari* to the Utility Water Act Group (UWAG), PSEG and Entergy in the *Riverkeeper II* case regarding the issue of whether the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available (BTA) for minimizing adverse environmental impact at cooling water intake structures. The Supreme Court will only be reviewing the cost-benefit issue. They will not be reviewing the Second Circuit decision on restoration (i.e. that restoration is not allowed to be used for impact reduction).

b) The chance of success is unknown at this time. However the fact that the Supreme Court chose this case out of the 18 pages of cases that were requested to be reviewed is encouraging. In addition, the Solicitor General filed a "Brief for the Federal Respondents in Opposition" (Attachment 1), on behalf of EPA that stated under "Argument" on Page 9,

> "1. Petitioners (i.e. UWAG, PSEG and Entergy) contend that the court of appeals erred in holding that, in determining BTA, EPA may not consider the relationship between a technology's cost and benefits. The government agrees."
>
> Therefore, the Solicitor General will be arguing, along with UWAG, that the cost-benefit test should be allowed to achieve compliance in the 316 (b) Phase II Rule.

c) The chance of success is unknown at this time. However, conversations with EPA rule-writers have indicated that technological and legal arguments that can support the rule-making effort (i.e. don't conflict with the Second Circuit remands or the Supreme Court decision) will be considered, which is a positive indication for the chances of success. Also, if states, such as Florida are willing to submit comments during the rule-making process, those comments will be given a great deal of weight.

Q.

Section 4 of the petition points out that the EPA has reinitiated rulemaking to address the areas of the Phase II Rule that were remanded by the Second Circuit. Please provide FPL's best estimate of the date when the EPA rulemaking process will be completed.

A.

According to the most recent conversations with EPA (April 17, 2008), the EPA is proposing to issue a draft rule by December 2008, with a final rule being published by late 2009. Obviously, this timeframe for publishing the final rule may change based on the outcome of the Supreme Court decision which will likely be published sometime during the summer of 2009.

Q.

Section 5 of the petition states that if the currently remanded provisions were removed from EPA's revised Phase II rule, the initial estimated compliance costs for retrofitting all FPL's affected facilities would exceed $1.5 billion.

a) Please identify or describe how this estimate was derived;

b) Please provide the cost components that contribute to the $1.5 billion.

A.

a) UWAG contracted the Electric Power Research Institute (EPRI), in conjunction with John Maulbetsch, a renowned cooling tower expert, to develop a "calculator" that will estimate the cost of retrofitting cooling towers onto an existing power plants. Factors considered are cooling water flow, difficulty of the retrofit (i.e. spatial, locational, geology, etc. issues), as well as many other factors. This calculator has been reviewed by EPA and the results from this effort will be submitted to EPA as part of the rule-making process. While final values will not be available until this fall, it is believed that the costs submitted will be in the same range as those provided herein with the exception of the retrofit cost at St. Lucie. EPRI is finding as they move through the process that retrofitting nuclear plants is substantially more expensive than first believed and certainly more expensive that retrofitting similarly sized fossil units.

b) See the following table for cost components. The $1.5 billion is only the capital cost. As shown in the documents that are provided in response to Request No. 2 in Staff's First Request for Production of Documents, there are substantial O&M costs, parasitic power requirements and heat rate penalties as well.

Plant	Capital
Cape Canaveral	$228
Cutler	$61
Ft. Myers	$210
Lauderdale	$106
Port Everglades	$361
Riviera	$163
Sanford Unit 3	$48
St. Lucie	$404
Total	$1,581

* Costs based on EPRI Model - November 2007

Q.

On April 13, 2007, FPL notified the Commission of EPA's decision to suspend the rule, and FPL's decision to continue its Comprehensive Demonstration Studies (CDS), irrespective of the ultimate outcome of EPA's further rulemaking (Section 5 of the LaBauve Affidavit).

a) Please identify the deadline (that EPA set up before the suspension of Phase II rule) for FPL submitting to the EPA a CDS;

b) Please identify the time line that FPL currently has for finishing its CWS in light of the changed circumstances regarding the Phase II rule;

c) Please provide up-to-date information regarding the data collection, analysis, and high level technology evaluation activities carried out and/or planned to be carried out in all FPL's facilities in support of submitting a CDS to the EPA.

A.

a) and b) See the following table for responses.

"Phase II" Plant	CDS deadline for Submittal Pre - Rule Suspension	Post-Rule Suspension
Cutler	1/7/2008	7/21/2010
St. Lucie	1/7/2008	7/23/2010
Port Everglades	3/18/2008	3/18/2008
Lauderdale	6/17/2008	6/17/2008
Riviera	8/12/2008	8/12/2008
Ft. Myers	11/14/2008	11/14/2008
Cape Canaveral	8/9/2010	8/9/2010
Sanford Unit 3	8/15/2006	8/15/2006

c) FPL is carrying out data collection, analysis and high level technology evaluation, as required to meet the FDEP's CDS expectations that apply while the 316(b) Phase II rule is remanded and the FDEP is therefore addressing the 316 (b) requirements in the NPDES permitting process by using the Best Professional Judgment (BPJ) approach that the FDEP had relied upon prior to the Phase II rule.

Q.

In Section 6 of the petition FPL states that it believes it is prudent for the company to take two actions to help limit the compliance cost impact of potential revisions to the Phase II Rule on FPL and its customers.

a) Section 366.8255 defines "environmental compliance cost" as "cost or expenses incurred by an electric utility in complying with environmental laws or regulations." Please explain how the above mentioned two actions could be defined as activities for complying with environmental laws or regulations rather than activities for changing/ making environmental laws or regulations.

b) FPL cited the "test" the Commission has adopted for determining whether costs qualify for ECRC recovery (PSC-94-0044-FOF-EI) "2. the activity is legally required to comply with a governmentally imposed environmental regulation ...." (Section 3 of the petition) Please explain how the above mentioned two actions could be defined as activities that are legally required to comply with the environmental regulation rather than activities for changing/making the regulation.

A.

A very similar issue was addressed in Docket No. 050007-EI, concerning FPL's request to recover the legal expenses associated with challenging the Clean Air Interstate Rule. In authorizing FPL to recover legal expenses prudently incurred for this challenge, the Commission made the following observations:

"We find that the definition of environmental compliance costs in Section 366.8255, Florida Statutes, includes prudently incurred litigation costs associated with FPL's complying with the Clean Air Interstate Rule. The costs of compliance with a rule and the cost of litigating the legitimacy of a rule are closely linked. To comply with a rule, the utility must understand the rule, and whether the rule is consistent with the statute under which it was adopted. If there is a legitimate argument that the rule is not consistent with the statute being implemented then the utility may recover the costs of challenging the rule through the ECRC."

Order No. PSC-05-1251-FOF-EI, dated December 22, 2005, at page 13.

FPL believes that the Commission expects utilities to take steps to control the level of costs that must be incurred for environmental compliance. Sometimes, an effective way to control the costs of complying with a particular environmental law or regulation is to participate in the regulatory and legal processes involved in defining compliance. That is the case here, and FPL believes that the rationale expressed in Order No. PSC-05-1251-FOF-EI with respect to the Clean Air Interstate Rule applies with equal force to FPL's attempts to control the costs of complying with Section 316 (b).

Q.

Please clarify whether FPL would violate any federal, state, or local environmental statute, administrative regulation, order, ordinance, regulation or other requirement, should FPL chose not to implement the two actions described in Section 6 of the petition.

A.

See response to Interrogatory No. 5 regarding the Commission's observations on the costs of compliance with a rule and the cost of litigating the legitimacy of a rule.

Q.

Section 6 of the petition specifies "the first action is encouraging various government agencies to participate in support of UWAG's position before the Supreme Court, in the event that the (Supreme) Court grants certiorari with respect to the Second Circuit ruling."

a) Please explain when FPL will commence this action, given that the Supreme Court is expected to rule on UWAG's petition for certiorari in the Spring of 2008 (Section 14 of the LaBauve Affidavit);

b) Please clarify whether FPL would need to take this action should the certiorari not be granted.

A.

a) FPL plans to commence this action in May 2008. However, at this time, we are planning to use in-house resources to meet with the Governor, Attorney General and FDEP to encourage them to become active in this process. FPL does not expect the ECRC recovery for the costs of these actions to be substantial.

b) N/A

Q.

Section 6 of the petition indicates that "the second action is targeted at the EPA's rulemaking effort to address the Second Circuit's remand. FPL would need to educate various state and federal agencies in an attempt to have them support the rulemaking (and possibly legislative) process so that a balanced and equitable rule is achieved ..."

a) Please explain whether FPL has engaged in similar actions before to influence the outcome of an EPA rule remand and rule revision, the actions FPL took, the results of that action, and how FPL recovered its legal and consultant's costs;

b) Please provide a table of contents of the materials or a summary of the messages that FPL plans to educate/ convey to the various government agencies in the current case.

A.

a) Yes. FPL did engage in similar action associated with the Clean Air Interstate Rule (CAIR). FPL had actively participated in the EPA rulemaking process for CAIR through EPA and FDEP sponsored workshops and by filing comments on proposed rules. FPL decided to challenge the CAIR when the final rule included provisions which were not in the best interest of FPL's customers. FPL's challenge of CAIR was implemented through use of available legal approaches, the first of which was a request for reconsideration during the rulemaking process at EPA to reconsider four provisions of the rule. The second approach was a petition for judicial review that was filed in the DC Circuit Court of Appeals of the final CAIR for a review of EPA's authority to implement those provisions in the rule that FPL and other petitioners were challenging. The challenge of CAIR required that technical deficiencies in the EPA rulemaking process be identified. FPL met with other interested utilities within Florida under the guidance of outside counsel and created the Florida Association of Electric Utilities (FAEU) to challenge specific provisions of CAIR that were of interest to the FAEU membership. FPL also retained counsel to challenge remaining provisions of CAIR which were not included within the scope of the FAEU challenge. The FPL and FAEU challenge of EPA's Final CAIR included studies that were conducted through the use of expert consultants to review the technical merits of EPA's analyses, perform similar analyses, and determine where errors had been made by EPA in the rulemaking process. In the CAIR challenge FPL and FAEU were unable to obtain necessary changes during the rulemaking process and have continued the rule challenge through court appeal of the rule. Recovery of FPL's costs associated with the technical analyses and legal challenges to CAIR have been approved by the Commission and are currently being recovered through the Environmental Cost Recovery Clause.

b) FPL intends to convey the following messages to various government agencies:

a. Cost to customers

i. The $1.5 billion dollar cost of constructing cooling towers (the worst case outcome for a rule without cost-benefit considerations) would be borne by customers of FPL through the ECRC

1. For most or all of FPL facilities the impact to the environment does not warrant that cost.

2. Operating expenses for the cooling towers would also be extremely high.

b. Loss of efficiency/parasitic load from retrofitting plants with cooling towers

i. FPL's Phase II facilities were designed to use once-through cooling water for cooling purposes. Retrofitting with cooling towers, without replacing the condensers of those facilities would result in less cooling, greater turbine backpressure and therefore, reduced efficiency. Thus, each of these facilities would require more fuel and produce more air emissions to generate the same amount of energy as they currently produce.

ii. The parasitic load to operate the pumps and fans associated with the cooling towers would significantly exceed the current parasitic load so more of the produced electricity would be utilized by the facility rather than sold on the grid. One estimate has shown that the combination of lost efficiency and parasitic load would be approximately 57 MW for these 8 facilities.

c. Impact on manatees

i. Five of the FPL Phase II facilities have "manatee protection plans" included in their State Industrial Wastewater permits. These plans require those facilities to provide warm water refuges (currently designated as critical manatee habitat) for manatees during the winter. Cooling towers would not be able to provide adequate volumes of water at a high enough temperature to keep the manatees warm. Thus, installation of cooling towers would put FPL in a conflict between the Clean Water Act and the Endangered Species Act.

d. Use of Freshwater

i. Currently all but one of the Phase II facilities use salt or brackish water for condenser cooling purposes. In most cases, due to the locations of these facilities, having saltwater cooling towers would potentially negatively impact the surrounding residents, businesses, highways, etc.

ii. Freshwater cooling towers would require millions of gallons per day/per facility that would be evaporated for cooling purposes. With Florida starved for freshwater already, this does not seem to be a prudent choice. Not only that, but the water is just not available (from Water Management Districts - WMD's).

e. Spatial/Locational Issues

i. Construction of cooling towers at all 8 facilities would be challenging from a spatial/locational standpoint. While many of the plants were in rural areas when they were built, cities and commercial areas have grown up around them. Most facilities would have difficulty siting a cooling tower within their current property boundaries, or would have to site them fairly remotely from the plant which increases cost significantly.

ii. Most of the facilities are close to highways or airports that would be impacted by fogging associated with cooling towers. Plume abatement technology is very expensive and requires in most cases for the cooling towers to be in a single line, rather than "back-to-back". This adds to the spatial problems.

iii. The aesthetic and noise issues associated with cooling towers, locating them in residential areas, would also make siting difficult.

f. Nuclear (St. Lucie) issues

i. Retrofitting nuclear plants with cooling towers is even more expensive than fossil plants of similar size. This is due to additional costs for licensing, security issues, size of cooling towers required, etc.

ii. Nuclear plants have virtually no air emissions associated with their operation. As mentioned above, the decreased efficiency and parasitic load would require replacement energy which results in increased air emissions. This situation is more pronounced when a fossil plant will have to supply replacement power for a nuclear plant.

g. Desalination

i. FDEP and various WMD's have been having conversations with FPL in an attempt to collocate desalination plants in associate with power plants that use once-through cooling. This option would no longer exist with cooling towers as the purpose of this collocation is to have the desalination plants dilute their relatively small amount of "brine" effluent by mixing it with the power plant's large quantity of once-through cooling water.

Q.

The Phase II Rule established performance standards to reduce the mortality of aquatic organisms by cooling water intake structures at certain large electric generating plants (Section 4 of the LaBauve Affidavit). Such provisions (e.g. restoration and cost-benefit test eligibility) have been remanded now and FPL is seeking to keep these provisions in the EPA's revised Phase II Rule (Section 7 and Section 10 of the LaBauve Affidavit).

a) Please provide the rationale, in the perspective of environmental protection, of keeping the remanded provisions in the revised Phase II Rule.

b) Please explain how restoration (mitigation) can guarantee the same results of reductions in impingement mortality and entrainment of fish and shellfish in power plant intakes as a full retrofit. Please provide relevant scientific data to support the explanation.

A.

a) Section 316(b) of the Clean Water Act requires that, "...the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for **minimizing adverse environmental impact**". In the suspended Phase II Rule, EPA, as the federal agency responsible for protecting our environment, promulgated a rule that did not define "adverse environmental impact" (AEI) but, rather required Phase II facilities to achieve certain performance standards for reduction of impingement mortality and entrainment which EPA believed would be protective of the environment (particularly fish and shellfish). Since retrofitting facilities with dry cooling towers was prohibitively expensive and not efficient in many areas of the country, they based those performance standards on the reduction of impingement mortality and entrainment that would be achieved by using cooling towers and would not result in AEI. FPL is asking EPA to keep as much of the Phase II rule in place as possible. The cost-benefit portion was crucial because in many instances, certain technologies do not work or cause even bigger problems than they solve. In most cases, impingement numbers are very small and while most facilities might entrain billions of organisms, when these numbers of egg and larval organisms are converted to "adult equivalents" that number too, is relatively small. Thus, for the cost-benefit provision, EPA (supported by previous Circuit Court rulings) had decided in the Phase II Rule that the cost for a technology should not be significantly greater than the benefit derived. This prevents companies from having to spend hundreds of millions of dollars to install technologies such as cooling towers in situations where there is little or no adverse environmental impact.

b) FPL did not plan to rely on the restoration provision and therefore is not planning to expend any significant resources to "revive" it.

Q.

In Section 7 of the petition, FPL states that it believes it is prudent for the company to contract with various law firms and consultants.

a) Please specify the specialties those various law firms will utilize and the activities in which they will be involved;

b) Please also specify the specialties those consultants will utilize and the activities in which they will be involved.

A.

a) Attorneys

- Bracewell Giuliani – Assist FPL in taking regulatory compliance options/concepts and converting them to rules that would be defensible in future court proceedings. Assist in organizing contacts/meetings with various regulatory/legislative officials to discuss related issues. Agencies that Brace-Giuliani might contact would include the Environmental Protection Agency (at various levels), Department of Energy, Council on Environmental Quality, the Office of Management and Budgets, as well as others.

- Bill Horn (Attorney), Birch, Horton, Bittner and Cherot Law Firm-- Mostly contacts related to the manatee and other wildlife related issues. Agencies he might contact would include the US Fish and Wildlife Service, Florida Department of Environmental Protection, Florida Fish and Wildlife Conservation Service, and others.

b) Consultant –ENSR – Assist with generating cooling tower impact information, evaluation biological information and then providing this information to enhance/support EPA's rule making effort.

Q.

Section 8 of the petition indicates that the initial O&M estimate is $700,000;

a) Please provide the details (cost components) that contribute to the $700,000.

b)Please provide the estimate of the total O&M costs (FPL's share) that would be required for achieving the goals described in Section 4 and Section 6 of the petition:

(1)Having the Supreme Court review the Second Circuit's ruling;

(2)Achieving a balanced and equitable rule.

A.

a) FPL's initial O&M estimates assumed the following:

1. Bracewell – Giuliani: retainer - $45,000/month
2. Bill Horn - Birch, Horton, Bittner and Cherot: retainer - $10,000/month
3. ENSR - $33,000 total cost
4. Total Cost for 12 months - $693,000

However, the final proposal from the attorneys contained slightly lower costs so the new estimates are:

1. Bracewell – Giuliani: retainer - $35,000/month
2. Bill Horn: retainer - $6,000/month
3. ENSR - $33,000 total cost
4. Total Cost for 12 months - $525,000

Please note, that, due to the granting of certiorari review by the Supreme Court and the uncertainty in the Rulemaking process., it is now likely that most of the expenditures will take place somewhat later than originally anticipated -- in late 2008 and 2009, following the release of the proposed Phase II Rule.

b) 1) FPL does not presently anticipate making substantial expenditures in support of the Supreme Court review, because EPA, UWAG and other groups are already planning to support that effort. It is possible, however, that FPL will be required to incur costs to provide backup support to EPA and/or UWAG.

2) Almost the entire $525,000 would be focused on achieving a balanced and equitable rule, with possibly a push for new legislation, if required.

Q.

Section 8 of the petition indicates that FPL is attempting to arrange for other utilities to share the cost of the proposed activities. Please provide the details of the status of these arrangements for each such utility.

A.

To date, no other utilities have agreed to split costs. Please see the response to Interrogatory No. 11 concerning support of the Supreme Court review of the Second Circuit's remand decision. FPL has found that other utilities with large stakes in the outcome of this rulemaking are putting their resources into supporting the Supreme Court review, which means that FPL therefore does not have incur the substantial costs to do so. In turn, other utilities are looking to FPL to bear the cost of proceeding on the rulemaking front.

Q.
Please specify how much has been set in FPL's base rates for the environmental litigation and consulting costs.

A.
FPL's MFRs in Docket No. 050045-EI, which were based on FPL's 2006 budget, do not include any environmental legal or legal-related consulting costs.

Q.
Please identify what would be the litigation and consulting costs (towards achieving the goals described in Section 6 of the petition) that FPL will spend in 2008.

A.
FPL's current projection for 2008 litigation and consulting costs related to this petition is $50,000.

Q.

Please quantify FPL's 2008 environmental litigation and consulting expenses (adjusted for escalation) that will not be covered in FPL's base rates for 2008.

A.

FPL's MFRs in Docket No. 050045-EI, which were based on FPL's 2006 budget, do not include any environmental legal or legal-related consulting costs, therefore, FPL's current projection for 2008 litigation and consulting costs related to this petition of $50,000 will not be covered in FPL's base rates for 2008.

10

FPL's response to Staff's Second Set of Interrogatories (Nos. 16 – 17)

HEARING EXHIBIT - 00000619

Q.

Refer to Form 42-8A on page 29-30 of 43 of the Final True-up Filing Schedule regarding the Port Everglades ESP (Project No. 25). Please explain or describe how the figures in line 4 were derived.

A.

The figures on line 4 from January through May 2007 represent the balance in work order 1662-924 (Port Everglades Unit 3 Electrostatic Precipitator Installation) while the work order was in Construction Work in Progress. This work order was placed in-service in June 2007. Please refer to FPL's response to Staff Third Request for POD, Question No. 4.

Q.

Refer to Form 42-8A on page 39-40 of 43 of the Final True-up Filing Schedules regarding the Deferred Gain on Sales of Emission Allowance:

a. Please explain or describe how the figures in line 1d were derived.

b. Please explain or describe why FPL used the Energy Jurisdictional Factor and Demand Jurisdictional Factor that were provided in 2005 ECRC Order of this Commission (PSC-05-1251-FOF-EI, II. F) rather than using the Factors that were provided in 2006 ECRC Order (PSC-06-0972-FOF-EI, II. F) in calculating line 11 and 13.

A.

a. The figures in line 1d represents the balance in Account 254.900. Please see FPL's response to Staff's Third Request for POD, Question No. 5.

b. FPL inadvertently used the previous years factors in Form 42-8A pages 39-40 of 43. The factors on lines 9 and 10 and the results on lines 11 through 13 are shown for information purposes only. The actual jurisdictionalization, based on Order PSC-06-0972-FOF-EI, II. F, are shown on Forms 42-5A and 42-7A.

The O&M costs, (Amortization of Gains), are allocated to energy and jurisdictionalized on Form 42-5A. The capital costs, (Negative Return on Investment) are allocated to energy and jurisdictionalized on Form 42-7A.

Attached please find the revised Form 42-8A using the factors approved in the ECRC Order PSC-06-0972-FOF-EI.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	End of Period Amount	
1	Working Capital Dr (Cr)									
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b 158.200 Allowances Withheld	0	0	0	0	0	0	0		
	c 182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
	d 254.900 Other Regulatory Liabilities-Gains	(2,105,917)	(2,094,333)	(2,082,750)	(2,071,166)	(3,150,774)	(2,864,494)	(2,924,623)		
2	Total Working Capital	($2,105,917)	($2,094,333)	($2,082,750)	($2,071,166)	($3,150,774)	($2,864,494)	($2,924,623)		
3	Average Net Working Capital Balance		(2,100,125)	(2,088,542)	(2,076,958)	(2,610,970)	(3,007,634)	(2,894,558)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(16,138)	(16,049)	(15,960)	(20,063)	(23,111)	(22,242)	(113,563)	
	b Debt Component (Line 6 x 1.87670% x 1/12)		(3,284)	(3,266)	(3,248)	(4,083)	(4,704)	(4,527)	(23,113)	
5	Total Return Component		($19,422)	($19,315)	($19,208)	($24,146)	($27,815)	($26,769)	($136,675)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(11,584)	(11,584)	(11,584)	(11,584)	(328,710)	(89,804)	(464,848)	
	b 411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	-	
	c 509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($11,584)	($11,584)	($11,584)	($11,584)	($328,710)	($89,804)	($464,848)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(31,006)	(30,899)	(30,791)	(35,730)	(356,525)	(116,573)		
	a Recoverable Costs Allocated to Energy		(31,006)	(30,899)	(30,791)	(35,730)	(356,525)	(116,573)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%		
10	Demand Jurisdictional Factor		98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%		
11	Retail Energy-Related Recoverable Costs (B)		(30,569)	(30,463)	(30,357)	(35,226)	(351,499)	(114,930)	(593,044)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($30,569)	($30,463)	($30,357)	($35,226)	($351,499)	($114,930)	($593,044)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding

HEARING EXHIBIT - 00000622

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	End of Period Amount	
1	Working Capital Dr (Cr)									
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b 158.200 Allowances Withheld	0	0	0	0	0	0	0		
	c 182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
	d 254.900 Other Regulatory Liabilities-Gains	(2,924,623)	(2,786,174)	(2,647,725)	(2,613,803)	(2,527,618)	(2,441,433)	(2,355,248)		
2	Total Working Capital	($2,924,623)	($2,786,174)	($2,647,725)	($2,613,803)	($2,527,618)	($2,441,433)	($2,355,248)		
3	Average Net Working Capital Balance		(2,855,399)	(2,716,950)	(2,630,764)	(2,570,711)	(2,484,526)	(2,398,340)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(21,941)	(20,877)	(20,215)	(19,754)	(19,092)	(18,429)	(233,871)	
	b Debt Component (Line 6 x 1.6698% x 1/12)		(4,466)	(4,249)	(4,114)	(4,020)	(3,886)	(3,751)	(47,599)	
5	Total Return Component		($26,407)	($25,126)	($24,329)	($23,774)	($22,978)	($22,180)	($281,470)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(138,449)	(138,449)	(33,922)	(86,185)	(86,185)	(86,185)	(1,034,223)	
	b 411.900 Losses from Dispositions of Allowances			0	0	0	0	0	-	
	c 509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($138,449)	($138,449)	($33,922)	($86,185)	($86,185)	($86,185)	($1,034,223)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($164,856)	($163,575)	($58,250)	($109,959)	($109,163)	($108,365)		
	a Recoverable Costs Allocated to Energy		(164,856)	(163,575)	(58,250)	(109,959)	(109,163)	(108,365)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%		
10	Demand Jurisdictional Factor		98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%		
11	Reserve Retail Energy-Related Recoverable Costs (B)		(162,532)	(161,269)	(57,429)	(108,409)	(107,625)	(106,838)	(1,297,145)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($162,532)	($161,269)	($57,429)	($108,409)	($107,625)	($106,838)	($1,297,145)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding

HEARING EXHIBIT - 00000623

11

FPL's response to Staff's Third Set of Interrogatories (Nos. 18 – 33)

HEARING EXHIBIT - 00000624

Q.

Regarding Item 22, 31 and 32, respectively, on pages 12, 14 and 15 of FPL's Petition for Approval of Three Solar Energy Projects, please describe or explain what is the expected in-service date for the first portion of solar generation for each project; and what are the expected MWs for the first portion of solar generation for each project.

A.

Martin Solar: The Martin Solar project is currently in the process of design and optimization of the layout and configuration of the solar field and the steam plant. Once this process is completed, then an estimate of the amount of generation expected and a description of the intial configuration can be provided. If as part of the optimization process it is determined that it would not be cost effective to phase-in the solar generation, then the entire 75 MW is expected to be placed into service by the end of 2010.

DeSoto Solar: The current construction of Desoto PV solar field is scheduled to begin in January 2009 for completion in December 2009. The PV solar field will most likely be commissioned in stages beginning in July 2009 and continuing until December. The final startup schedule for the PV solar fields is currently being developed. It is anticipated that each phase will be 5 MW.

Space Coast Solar: The current construction of Space Coast PV solar field is scheduled to begin in September 2009 for completion in July 2010. Commissioning of the PV solar field will most likely be in stages of 2 MW increments beginning in April 2010. The final startup schedule for this work will not be developed until mid year 2009. As part of the compensation for the land lease with Kennedy Space Center, FPL will also commence construction of the Kennedy Space Center PV solar field during the first quarter of 2009.

Q.

Please describe or explain FPL's plan to add incremental additional solar capacity for each project after the in-service dates for the first portion of solar generation for each of the three solar projects.

A.

Please see FPL's response to Staff's Third Set of Interrogatories No. 18.

Q.

Regarding FPL Energy Company's 310 MW SEGS described on page 12 of FPL's petition (Item 24), please describe or explain what is the:
a. Technology used in that solar facility;

b. Life-time (in-service years) of that facility before and after the upgrade.

A.

a. Similar to what is being proposed at Martin Solar, the SEGS facility is concentrating solar power utilizing solar thermal trough technology. The parabolic trough solar collectors track the sun in order to collect and concentrate the sun's energy onto heat collection elements located in the focal line of the parabolic reflectors. The heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation. The heated transfer fluid is then circulated to heat exchangers that produce steam which is routed to a steam turbine generator. The SEGS facility consists of seven separate solar fields and steam turbine generators.

b. The original estimated service life of the SEGS facilities was 30 years. The newly installed heat collection elements have a manufacturer's predicted service life of 30 years which when added to each of the SEGS facilities could result in a remaining service life of from 39 years to 43 years.

Q.

Regarding FPL Energy Company's 250 MW solar thermal facility described on page 12 of FPL's petition (Item 24), please describe or explain what are the :

a. Technology used in that solar facility;

b. Life-time (in-service years) of that facility;

c. Projected construction costs, in-service costs, and O&M costs associated with the completed project.

A.

On March 14, 2008, FPL Energy filed with the California Energy Commission (CEC) an Application for Certification of the Beacon Solar Energy Project (Beacon Solar). The application has been deemed incomplete by the CEC at this time. The project is still in the development stage with a planned in-service date of 2012 or later, and is subject to final technology selection.

a. Similar to the SEGS facilities and what is being proposed at Martin Solar, the proposed Beacon facility, as currently being planned, will be concentrating solar power utilizing solar thermal trough technology. The parabolic trough solar collectors will track the sun in order to collect and concentrate the sun's energy on to heat collection elements located in the focal line of the parabolic reflectors. The heat collection elements will contain a heat transfer fluid which is heated by the concentrated solar radiation. The heated transfer fluid will then circulated to heat exchanger(s) that produce steam which will be routed to a steam turbine generator.

b. The estimated service life of the Beacon Solar project is 30 years.

c. The only available cost for the plant at this time is the total capital cost, which is estimated at approximately $1 billion.

Q.

Please explain what are the specific reasonable and customary industry practices FPL used in the design, procurement, and construction of each project in a cost effective manner appropriate to the location of the facility.

A.

For both DeSoto and Space Coast PV solar fields, FPL has entered into a turnkey EPC contract with a highly qualified supplier and contractor experienced in utility-scale projects. As part of the process, FPL followed a well-defined request for information ("RFI") process which was initially conducted in 2007 with responses from 26 international and domestic companies involved in the development, manufacturing, and construction of utility-scale PV systems and projects. In February of 2008 a request for proposals ("RFP") was issued which resulted in responses from 8 companies of which 4 provided conforming proposals after obtaining bid clarifications and conducting an initial screening evaluation. A detailed bid evaluation on the conforming proposals identified two low bidders. Initial negotiations with the two companies was conducted which resulted in a final selection.

FPL is using trained and qualified employees with extensive experience in designing, procuring, and constructing utility facilities to oversee the project management aspects of the PV projects.

FPL's approach to designing, procuring, and constructing the Martin Solar project will be more complicated due to several unique attributes of the project.

DESIGN & ENGINEERING: Several different experienced engineering companies have and/or will be utilized for different phases of the project. Worley Parsons developed the conceptual design in order to prepare initial estimates, schedules, performance predictions, and permit support. Because this first of a kind project will send solar field steam into an existing operating combined cycle unit, FPL has retained Black & Veatch, the original design engineer for Martin Unit 8, to design all interfaces between the existing plant and the new solar field. This approach will minimize costs associated with understanding the design limitations of the existing facility. FPL had discussions with the key solar industry engineering suppliers and is now negotiating with a joint venture company (Kiewit-MAN Solar Millennium; or "K-MSM") to potentially supply solar field engineering, procurement, and construction support services to the project. FPL has issued a limited notice to proceed to K-MSM for early solar engineering work while the negotiation process continues.

EQUIPMENT PROCUREMENT: FPL is currently working with the leading global suppliers of solar components to develop the most cost effective solutions to support the Martin project requirements. These contracts are expected to be awarded by the 4th quarter of 2008.

CONSTRUCTION: FPL is in discussion with several potential construction contractors for the Martin Solar Energy Center.

Q.

Regarding the FPL's lease of property at KSC (NASA John F. Kennedy Space Center Enhanced Use Lease), please describe or explain what is FPL's economic analysis that supports the nonmonetary and monetary considerations appearing in Article 3 of the lease relative to other comparable alternative sites that may have been available to FPL.

A.

In December 2007, FPL commissioned an appraisal of the NASA land to ascertain the fair market value (FMV) of the property. The FMV amount referenced in the lease represents the low end of the range identified in the appraisal. The appraised value was determined using a sales comparison approach, which identified three comparable properties within close proximity to the site that were most indicative of past market activity. The values of those three comparable properties ranged from 33%-65% higher than the final value of the NASA property, which was discounted due to the slower market conditions at the time of the appraisal. The lease payment negotiated with NASA provides for an annual payment of 10% of the FMV, which is consistent with generally accepted market values for property rental rates. While the lease payment consists of non-monetary consideration, the total of the non-monetary consideration to NASA does not exceed the amount FPL would have paid to lease the property solely for monetary consideration. A copy of the Property Appraisal is provided in item 12b of Staff's Fourth Request for Production of Documents.

Q.

Please list the dates that FPL expects to enter into each of the various contracts for the design, procurement, and construction of each of the three projects.

A.

For the Martin Solar project, FPL awarded the balance-of-plant engineering contract in July, 2008. FPL expects to complete negotiation of a solar field engineering, procurement, and construction support services contract by the 4th quarter of 2008. (A limited notice to proceed with the early solar field engineering activities associated with this contract was issued in August 2008.) FPL expects to begin awarding the construction contracts as early as the 4th quarter of 2008.

The EPC contract for DeSoto Solar was awarded July 3, 2008 and the EPC contract for Space Coast Solar was awarded July 9, 2008.

Q. For each of the three solar projects, please describe what are the costs of services, costs of products, and associated costs provided by each vendor under contract to FPL Energy, FPL Group, and internally by FPL.

A.It is anticipated that all contracts to vendors for services and products associated with the three solar field projects will be issued by FPL. Additionally, FPL will incur internal expenses for each project. The following table summarizes FPL's approximate internal costs through July 2008:

INTERNAL FPL COSTS FOR THREE SOLAR PROJECTS (APPROX - THROUGH JULY 2008)

Martin Solar Project	$400,000
DeSoto Solar Project	$120,000
Space Coast Solar Project	$190,000

The tables below describe the approximate costs of services, products, and associated costs provided by vendors to date:

MARTIN SOLAR PROJECT:

Company	**Service**	**Contract Value, $**
WorleyParsons Engineering	Conceptual Design	[redacted]
Boyle Engineering	Conceptual Design	
Black & Veatch Engineering	Detailed Design	
Augustyne & Company	Solar Meter Supply	
Golder Associates	Permit Support	
Lucido & Associates	Land Planning	
Richard L. Shepard & Associates	Permit Support	
Scrivner Energy Consultants	Conceptual Design	
LBFH	Permit Support	
Kiewit-Man Solar Millennium	Limited Notice to Proceed-Early Solar engineering	
FPL Energy	Engineering and Project management support	[redacted]

DeSoto Solar and Space Coast Solar Projects:

Supplier	**Service**	**Applicability**	**Contract Value $**
Archaeological & Historical Conservancy	Site Assessment	DeSoto	[redacted]
Boyle Engineering	Conceptual Design	DeSoto	
Ecology & Environment	Environmental Assessment	Space Coast	
Golder Associates	Permit Support	Both	[redacted]
Pandion Systems	Site Analysis	Space Coast	
SF Holden	Property Appraisal	Space Coast	
Wilson Miller	Permit Support	DeSoto	
Sun Power	EPC	DeSoto	
Sun Power	EPC	Space Coast	
Budnick	Proj Mgmt Services	DeSoto	
Budnick	Proj Mgmt Services	Space Coast	[redacted]
FPL Energy	Engineering & Proj Mgmt Services	DeSoto	[redacted]
FPL Energy	Engineering & Proj Mgmt Services	Space Coast	[redacted]

Q.

Please describe what are the estimated replacement power costs resulting from any planned or forced outages associated with the installation of Martin Solar throughout the construction period.

A.

There are no estimated replacement power costs currently associated with the installation of the Martin Solar Project. FPL presently expects that the work associated with the installation of Martin Solar will be completed during maintenance outages scheduled for Martin 8 that are unrelated to the Martin Solar Project.

Q.

Please state whether the replacement power costs discussed in interrogatory No. 26 above are included in the estimated costs of the Martin Solar Project.

A.

For the reasons expressed in FPL's response to Staff's Third Set of Interrogatories No. 26, FPL has not, at this time, included replacement power costs in the estimated costs.

Q.
Please state what will be the life-time (in-service years) for each of the three solar generation facilities.

A.
The Martin Solar generating facility is expected to be in service as long as Martin Unit 8 remains in service. There will be 20 years of book life
remaining on Martin Unit 8 when the solar project is placed in service at the end of 2010.

The DeSoto and Space Coast solar fields and associated equipment are being designed for a plant life of 25 years.

Q.

For each of the three solar generation facilities, please describe the potential for upgrading and the additional in-service years resulting from the upgrades.

A.

The three solar facilities will use state of the art technology. FPL, at this time, has not identified the opportunity for upgrading the three solar generation facilities beyond what is being proposed to be installed. However, there may be opportunities at both the DeSoto and Space Coast sites to expand and/or upgrade the facilities in the future. These facilities have additional land available and design characteristics that permit streamlined expansions or upgrades to occur.

Q. Regarding FPL's statement on page 10 of its petition (Item 17) that the Martin Solar project will consist of up to approximately 180,000 mirrors over 500 acres, please respond to the following questions:

a. Will these mirrors be manufactured overseas?
b. If "yes", what is the estimated variance of the capital costs due to fluctuations in the value of the U.S. dollar, as FPL mentioned on page 18 of its petition (Item 43)?
c. Concerning the significance of the numbers, what is the estimated frequency of maintenance and replacement of these mirrors, and what will be the associated O&M costs?

a. The manufacturing location of the mirrors has not been determined at this time. FPL is currently in discussions with both domestic and international mirror suppliers. Some of the international suppliers are working to establish manufacturing facilities in the U.S., including possibly Florida, to service the growing domestic solar market.

b. FPL is unable to estimate this variance (if any) at this time as the supplier has not been determined.

c. The total O&M is estimated to be $[redacted]/kw, a portion of which will relate to maintenance and replacement of the mirrors. This estimate assumes an annual mirror replacement of 0.3%. The cost for the replacement mirrors is estimated at approximately $100,000 per year.

Q.

Regarding FPL's statement on page 18 of its petition (Item 43) "many key components are currently manufactured overseas," please respond to the following questions:

a. Does this statement apply to the PV solar panels that will be used in DeSoto Solar and Space Coast Solar projects?

b. If "yes", what is the estimated variance of the capital costs due to the fluctuations in the value of the U.S. dollar, as FPL mentioned on page 18 of its petition (Item 43)?

A.

a. The PV panels for DeSoto and Space Coast projects are being manufactured overseas.

b. Since the contract with the EPC contractor for both sites is a Fixed Cost Lump Sum U.S. dollar-denominated, it will not be subject to currency fluctuations.

Q.
Please describe or explain, in detail if possible, the scope of FPL's Greenhouse Gas (GHG) Reduction Program.

A.
The purpose of FPL's proposed Greenhouse Gas Reduction Program is to implement both the reporting and emission reduction requirements established under Chapter 403 of the Florida Statutes, as amended by HB 7135. HB 7135 provides for a regulatory and legislative process to implement the Governor's Executive Order 07-127 that set a maximum allowable emission level of greenhouse gasses in the state of Florida. The Environmental Protection Agency (EPA) has also received appropriations to begin rulemaking for the mandatory reporting of GHG emissions from sources. A proposed rule is anticipated from EPA by September of 2008 with a final rule promulgated by June of 2009.

HB 7135 requires major emitters, including electric utilities, to report GHG emissions to the nonprofit partnership "The Climate Registry" providing historical and current greenhouse gas emission data to establish the baseline emissions and targets for the required compliance reductions to meet the 2017, 2025 and 2050 goals established in the Governor's executive order 07-127. FPL plans to comply with State reporting requirements for its GHG emissions through participation in The Climate Registry reporting program. Reporting GHG emissions to the registry requires an annual membership fee, use of specific reporting protocols for the calculation and reporting of GHG emissions in an electronic reporting system, and third party verification of reported emissions to provide accreditation for the reporting entity's emissions. FPL plans to begin GHG reporting activities in 2009 as it implements FPL's Greenhouse Gas Reduction Program. FPL has proposed to recover the costs associated with joining the registry and the preparation of the initial GHG report.

HB 7135 required that DEP initiate rulemaking activities to establish a Florida GHG cap-and-trade program no earlier than January 1, 2010. Details of that program have not yet been established and it is unknown at this time whether allowances will be allocated to sources in whole or in part or available only at auction. Regardless of whether the allowances are allocated or auctioned the CO2 allowances become part of the fossil generation costs. FPL has included CO2 emission allowance market price projections in its evaluation of proposed generation expansion projects including its proposed Nuclear Uprate projects, Turkey Point Nuclear Unit 6 & 7 expansion, West County Energy Center 3 and the proposed Conversion Projects at Riviera and Cape Canaveral Plants. Future CO2 allowance and program management costs would be included in FPL's Greenhouse Gas Reduction Program.

FPL's nuclear, renewable and conversion generation projects along with our energy efficiency program will reduce greenhouse gas emissions which will help to achieve compliance with the Cap and Trade rule being developed by DEP. To achieve the future reduction goals established by the Executive Order, which will be included in DEP's Cap and

Trade rule, FPL anticipates that additional reductions in its GHG emissions will be required beyond the currently planned projects. The additional reductions will likely require a combination of the implementation of carbon sequestration and storage technology and the use of verified carbon offset projects. Costs associated with the implementation of controls and storage technologies for GHG emission reductions, and prudently incurred costs for required offsets for mitigation of GHG emissions to comply with regulations would also be included in FPL's Greenhouse Gas Reduction Program.

Q.
Please provide workpapers (break down in line items) to support FPL's estimate of $50,000 O&M costs for the 2009 initial implementation of the projected GHG registration and consultant fees.

A.
FPL tentatively plans to begin implementation of its Greenhouse Gas Reduction Program in 2009 and has projected costs for this project in 2009 associated with participation in The Climate Registry. FPL expects to begin incurring such costs following publication of registry guidance and rulemaking by the DEP, which is anticipated to occur prior to June 2009 date for the final federal mandatory GHG emissions reporting rule. FPL's preliminary estimate of $50,000 in 2009 O&M expenses for the project includes the projected registration and consultant fees for the first year of Climate Registry participation. Specifically, FPL anticipates the following required activities in 2009 for The Climate Registry:

1. Annual Membership Fee for joining The Climate Registry: $15,000
(annual fee is $10,000 and includes additional one time fee of $5,000 for reporting prior year baseline emissions)

2. Preparation of GHG Baseline Emission Inventory for FPL: $20,000
(includes contractor labor costs for identification of emission source data, selection and application of registry approved methods, and quantification of baseline GHG emission data)

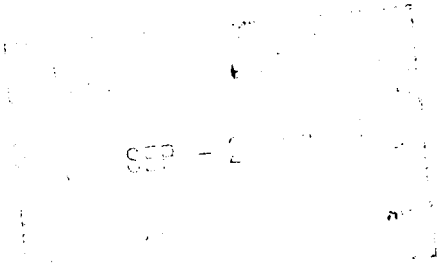
3. Preparing, formatting, and data entry of FPL emissions data for submittal to the Climate Registry Information System (CRIS): $15,000 (includes contractor labor costs associated with data entry for: a) Creation of corporate/entity profile inputs; b) Creation of facility accounts with location specific information; c) Populating entities with baseline GHG emission inventory data into on-line reporting system)

12

FPL's response to Staff's Fourth Set of Interrogatories (Nos. 34 - 45)

Q.
For each of the three solar projects, please provide the information requested in the attached tables 1-1 through 1-2. Monthly data should be provided for a full calendar year.

A.
Attached are the completed tables 1-1 through 1-2 which contain the most current information.



Solar Project Name : Space Coast (NASA)
Estimated Data

Cost data		
	Fixed Array	**Tracking**
Incremental Gross Capacity (MW)	10	Not Applicable
Incremental Net Capacity (MW)	10	Not Applicable
Construction start date [1]	1st Quarter 2009	Not Applicable
In-service date	3rd Quarter 2010	Not Applicable
Useful life (years)	30	Not Applicable
Total Site area	60 acres	Not Applicable
Overnight construction costs ($/kw) [2]	7,790	Not Applicable
CWIP ($)	4,277,000	Not Applicable
Total installed costs ($/kw) [2]	7,890	Not Applicable
Fixed O&M ($/kw-yr) 2009 $	[redacted]	Not Applicable
Capital replacement ($/kw-yr) 2009 $	[redacted]	Not Applicable
Variable O&M ($/MWH)	0	Not Applicable

Annual Performance Data		
	Fixed Array	**Tracking**
Incremental Gross Capacity (MW)	10	Not Applicable
Incremental Net Capacity (MW)	10	Not Applicable
Planned outage factor	Not Applicable	Not Applicable
Forced outage factor	Not Applicable	Not Applicable
Equivalent availability factor	98%	Not Applicable
Net annual generation (MWH) 1st year in -service	18,662	Not Applicable
Resulting capacity factor (% on-peak) [3]	21.30%	Not Applicable
Resulting capacity factor (% off-peak) [3]	0	Not Applicable
Average capacity factor (%) 1st year in-service	21.3%	Not Applicable
Water consumption (gallons)	0	Not Applicable

(1) includes site preparation and related work required by long term land lease.
(2) $/kW for over night and year in-service excludes CWIP and includes net present value of the long term land lease
(3) It was assumed that all generation will occur during on-peak hours.

Solar Project Name : De Soto
Estimated Data

Cost data		
	Fixed Array	**Tracking**
Incremental Gross Capacity (MW)	Not Applicable	25
Incremental Net Capacity (MW)	Not Applicable	25
Construction start date	Not Applicable	1st Quarter 2009
In-service date	Not Applicable	4th Quarter 2009
Useful life (years)	Not Applicable	30
Total Site area	Not Applicable	180 acres
Overnight construction costs ($/kw) [1]	Not Applicable	6,831
CWIP ($)	Not Applicable	9,228,000
Total installed costs ($/kw) [1]	Not Applicable	6,937
Fixed O&M ($/kw-yr) 2009 $	Not Applicable	[redacted]
Capital replacement ($/kw-yr) 2009 $	Not Applicable	
Variable O&M ($/MWH)	Not Applicable	0

Annual Performance Data		
	Fixed Array	**Tracking**
Incremental Gross Capacity (MW)	Not Applicable	25
Incremental Net Capacity (MW)	Not Applicable	25
Planned outage factor	Not Applicable	Not Applicable
Forced outage factor	Not Applicable	Not Applicable
Equivalent availability factor	Not Applicable	98%
Net annual generation (MWH) 1st year in -service	Not Applicable	54,738
Resulting capacity factor (% on-peak) [2]	Not Applicable	25.0%
Resulting capacity factor (% off-peak) [2]	Not Applicable	0
Average capacity factor (%) 1st year in-service	Not Applicable	25.0%
Water consumption (gallons)	Not Applicable	0

(1) $/kW for over night and year in-service excludes CWIP

(2) It was assumed that all generation will occur during on-peak hours.

Solar Project Name : Martin solar thermal
Estimated Data

Cost data		
	Fixed Array	**Tracking**
Incremental Gross Capacity (MW) [1]	Not Applicable	79
Incremental Net Capacity (MW)	Not Applicable	75
Construction start date	Not Applicable	Dec-08
In-service date	Not Applicable	Dec-10
Useful life (years)	Not Applicable	20
Total Site area (acres)	Not Applicable	600
Overnight construction costs ($/kw) [2]	Not Applicable	6,175
CWIP ($)	Not Applicable	51,686,000
Total installed costs ($/kw) [2]	Not Applicable	6,350
Fixed O&M ($/kw-yr) 2009 $	Not Applicable	[redacted]
Capital replacement ($/kw-yr) 2009 $	Not Applicable	
Variable O&M ($/MWH)	Not Applicable	0

Annual Performance Data		
	Fixed Array	**Tracking**
Incremental Gross Capacity (MW) [1]	Not Applicable	79
Incremental Net Capacity (MW)	Not Applicable	75
Planned outage factor	Not Applicable	0
Forced outage factor	Not Applicable	0
Equivalent availability factor	Not Applicable	100%
Net annual generation (MWH) 1st year in -service	Not Applicable	155,000
Resulting capacity factor (% on-peak) [3]	Not Applicable	23.6%
Resulting capacity factor (% off-peak) [3]	Not Applicable	0
Average capacity factor (%) 1st year in-service	Not Applicable	23.6%
Water consumption (gallons) [4]	Not Applicable	0

(1) Parasitic load estimated at 4MW.
(2) $/kW for overnight and year in-service excludes CWIP
(3) It was assumed that all generation will occur during on-peak hours.
(4) No incremental water use, gallons/MWH for production of electricity.

Solar Project Name : Martin Solar Thermal
Estimated Data

Florida Power & Light Company
Docket No. 080007-EI
Staff's Fourth Set of Interrogatories
Question No. 34
Table 1-2
Page 1 of 1

	Monthly Performance Data											
	1	2	3	4	5	6	7	8	9	10	11	12
Incremental Gross Capacity (MW)	79	79	79	79	79	79	79	79	79	79	79	79
Incremental Net Capacity (MW)	75	75	75	75	75	75	75	75	75	75	75	75
Planned outage factor	0%											
Forced outage factor	0%											
Equivalent availability factor	100%											
Net monthly generation (MWH) 1st year in -service	12,645	12,362	15,725	15,142	13,762	11,567	12,592	12,567	11,563	12,512	11,542	12,878
Resulting capacity factor (% on-peak) (1)	See average capacity factor below											
Resulting capacity factor (% off-peak) (1)	0											
Average capacity factor (%)	23%	25%	28%	28%	25%	21%	23%	23%	21%	22%	21%	23%
Water consumption (gallons) (2)	0	0	0	0	0	0	0	0	0	0	0	0

(1) It was assumed that all generation will occur during on-peak hours.
(2) No incremental water use for production of electricity

HEARING EXHIBIT - 00000649

Q.

Please provide the information requested in the attached tables 1-3 through 1-4. Monthly data should be provided for a full calendar year.

A.

Attached are tables 1-3 through 1-4. The information provided is based on a greenfield simple cycle combustion turbine to be in-service in 2010.

Utility-Owned Combustion Turbine Data
Estimate

Cost data	
Incremental Gross Capacity (MW) winter/summer	183 / 164
Incremental Net Capacity (MW) winter/summer	181 / 162
Construction start date	Mar-09
In-service date	Jun-10
Useful life (years)	25
Total Site area (acres)	30
Overnight construction costs ($/kw)	1,000
AFUDC ($)	11,106,708
Total installed costs ($/kw)	1,114
Fixed O&M ($/kw-yr)	[redacted]
Capital replacement ($/kw-yr)	
Variable O&M ($/MWH)	

Annual Performance data	
Incremental Gross Capacity (MW) winter/summer	183 / 164
Incremental Net Capacity (MW) winter/summer	181 / 162
Planned outage factor	1.6%
Forced outage factor	1.0%
Equivalent availability factor	97.4%
Net generation (MWH)	169,160
Resulting capacity factor (% on-peak)*	NA
Resulting capacity factor (% off-peak)*	NA
Average capacity factor (%)	11.4%
Water consumption (gallons)	4.4 Million
CO2 emissions (tons)	110,333
NOx emissions (tons)	31
SO2 emissions (tons)	6
Hg emissions (tons)	0
Natural gas burned (mmBTUs)	1,886,039
Oil burned (mmBTUs)	0

* All generation is assumed to take place during off-peak hours.

Utility-Owned Combustion Turbine Data
Estimate

Florida Power & Light Company
Docket No. 080007-EI
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Table 1-4
Page 1 of 1

Monthly Performance data												
	1	2	3	4	5	6	7	8	9	10	11	12
Incremental Gross Capacity (MW)	183	183	183	164	164	164	164	164	164	164	183	183
Incremental Net Capacity (MW)	181	181	181	162	162	162	162	162	162	162	181	181
Planned outage factor	2%											
Forced outage factor	1%											
Equivalent availability factor	97%											
Net generation (MWH)	8,215	4,135	3,367	6,532	8,196	14,347	17,718	25,070	13,997	25,552	7,559	34,474
Resulting capacity factor (% on-peak)*	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Resulting capacity factor (% off-peak)*	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Average capacity factor (%)	6%	3%	3%	6%	7%	12%	15%	21%	12%	21%	6%	26%
Water consumption (gallons)	367,000	367000	367000	367000	367000	367000	367000	367000	367000	367000	367000	367000
CO2 emissions (tons)	5,190	2,613	2,127	4,127	5,178	9,064	11,194	15,839	8,843	16,144	8,234	21,781
NOx emissions (tons)	1	1	1	1	1	3	3	4	2	5	2	6
SO2 emissions (tons)	0	0	0	0	0	0	1	1	0	1	0	1
Hg emissions (tons)	-	-	-	-	-	-	-	-	-	-	-	-
Natural gas burned (mmBTUs)	88,717	44,663	36,359	70,544	88,516	154,945	191,350	270,754	151,165	275,961	140,746	372,319
Oil burned (mmBTUs)	-	-	-	-	-	-	0	0	-	-	-	-

* All generation is assumed to take place during off-peak hours.
** Energy generated and emission data based on historical performance of similar units.

HEARING EXHIBIT - 00000652

Q.

For the Martin Solar Project, please provide the information requested in the attached table 1-5. Monthly data should be provided for a full calendar year.

A.

Attached is table 1-5 (2 tabs) providing estimated monthly performance for Martin Unit 8 with and without the solar steam contribution.

Solar Project Name : Martin Solar Thermal
Estimated Data

Florida Power & Light Com
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Question No. 36
Table 1-5
Page 1 of 2

Monthly Performance Data

Martin With Solar Steam Generator

	1	2	3	4	5	6	7	8	9	10	11	12
Gross Capacity (MW)	1192	1192	1192	1126	1126	1126	1126	1126	1126	1126	1192	1192
Net Capacity (MW)	1170	1170	1170	1104	1104	1104	1104	1104	1104	1104	1170	1170
Planned outage factor	0.0%	0.0%	0.0%	0.0%	1.3%	66.9%	0.0%	0.0%	16.7%	0.0%	0.0%	0.0%
Forced outage factor	4.7%											
Equivalent availability factor	95.3%	95.3%	95.3%	95.3%	94.1%	28.4%	95.3%	95.3%	78.6%	95.3%	95.3%	95.3%
Net generation (MWH) (1)	475,275	481,034	610,785	669,813	606,820	212,639	695,155	704,549	561,917	737,413	621,713	554,272
Resulting capacity factor	55%	61%	70%	84%	74%	27%	85%	86%	71%	90%	74%	64%
(% on-peak) (2)	NA											
(% off-peak) (2)	NA											
Average capacity factor (%)	69.9%											
Water consumption (gallons) (3)	1.380 Million Gallons Per Year											
CO2 emissions (tons)	184,034	186,438	236,715	260,428	235,918	79,986	271,524	275,270	218,931	288,366	242,726	215,367
NOx emissions (tons)	27,595	27,955	35,494	39,050	35,374	11,993	40,713	41,275	32,827	43,239	36,395	32,293
SO2 emissions (tons)	9	10	12	13	12	4	14	14	11	15	12	11
Hg emissions (tons)	0	0	0	0	0	0	0	0	0	0	0	0
Natural gas burned (mmBTUs)	3,145,884	3,186,970	4,046,408	4,451,763	4,032,794	1,367,290	4,641,428	4,705,478	3,742,407	4,929,328	4,149,163	3,681,479
Oil burned (mmBTUs)	0	0	0	0	0	0	0	0	0	0	0	0

(1) Data based om projected 2011 operation

(2) Data not available

(3) Water consumption estimated for entire power plant

HEARING EXHIBIT - 00000654

Solar Project Name : Martin Solar Thermal
Estimated Data

Florida Power & Light Compa
Docket No. 080007-EI
Staff's Fourth Set of Interroga
Question No. 36
Table 1-5
Page 2 of 2

Monthly Performance Data

Martin W/O Solar Steam Generator

	1	2	3	4	5	6	7	8	9	10	11	12
Gross Capacity (MW)	1192	1192	1192	1126	1126	1126	1126	1126	1126	1126	1192	1192
Net Capacity (MW)	1170	1170	1170	1104	1104	1104	1104	1104	1104	1104	1170	1170
Planned outage factor	0.0%	0.0%	0.0%	0.0%	1.3%	66.9%	0.0%	0.0%	16.7%	0.0%	0.0%	0.0%
Forced outage factor	4.7%											
Equivalent availability factor	95.3%	95.3%	95.3%	95.3%	94.1%	28.4%	95.3%	95.3%	78.6%	95.3%	95.3%	95.3%
Net generation (MWH) (1)	462,630	468,672	595,060	654,671	593,058	201,072	682,563	691,982	550,354	731,157	610,171	541,394
Resulting capacity factor	53%	60%	68%	82%	72%	25%	83%	84%	69%	89%	72%	62%
(% on-peak) (2)	NA											
(% off-peak) (2)	NA											
Average capacity factor (%)	68.4%											
Water consumption (gallons) (3)	1,350 Million Gallons Per Year											
CO2 emissions (tons)	184,034	186,438	236,715	260,428	235,918	79,986	271,524	275,270	218,931	290,854	242,726	215,367
NOx emissions (tons)	27.595	27.955	35.494	39.050	35.374	11.993	40.713	41.275	32.827	43.612	36.395	32.293
SO2 emissions (tons)	9	10	12	13	12	4	14	14	11	15	12	11
Hg emissions (tons)	0	0	0	0	0	0	0	0	0	0	0	0
Natural gas burned (mmBTUs)	3,145,884	3,186,970	4,046,408	4,451,763	4,032,794	1,367,290	4,641,428	4,705,478	3,742,407	4,971,868	4,149,163	3,681,479
Oil burned (mmBTUs)	0	0	0	0	0	0	0	0	0	0	0	0

(1) Data based om projected 2011 operation

(2) Data not available

(3) Water consumption estimated for entire power plant

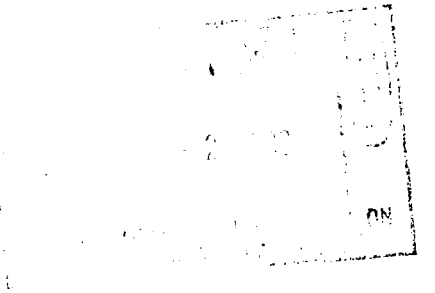
HEARING EXHIBIT - 00000655

Q.

Please provide a side-by-side comparison of the revenue requirements for each solar project compared to payments that could be made for an equivalent amount of capacity and/or energy pursuant to FPL's standard offer contract filed in Docket No. 080193-EQ. Please provide a detailed explanation of all assumptions.

A.

FPL's Standard Offer Contract, filed in Docket No. 080193-EQ, requires that a project provide both firm capacity and energy to FPL. FPL's Martin Solar project provides steam to be used in the Martin 8 unit and does not add any capacity to the system. FPL is currently assuming that solar PV projects do not provide any firm capacity pending actual operating data of the projects during peak hours. Therefore all three projects are considered to provide energy on as-available basis. Since these projects do not provide firm capacity, a comparison of their revenue requirements versus payments to be received under FPL's Standard Offer Contract would not be a meaningful comparison.

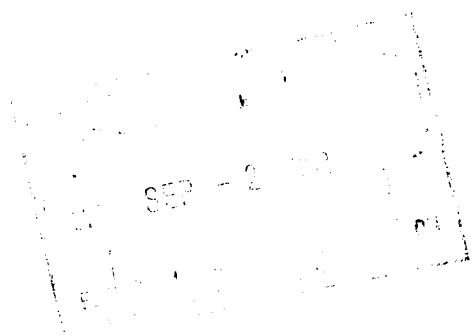


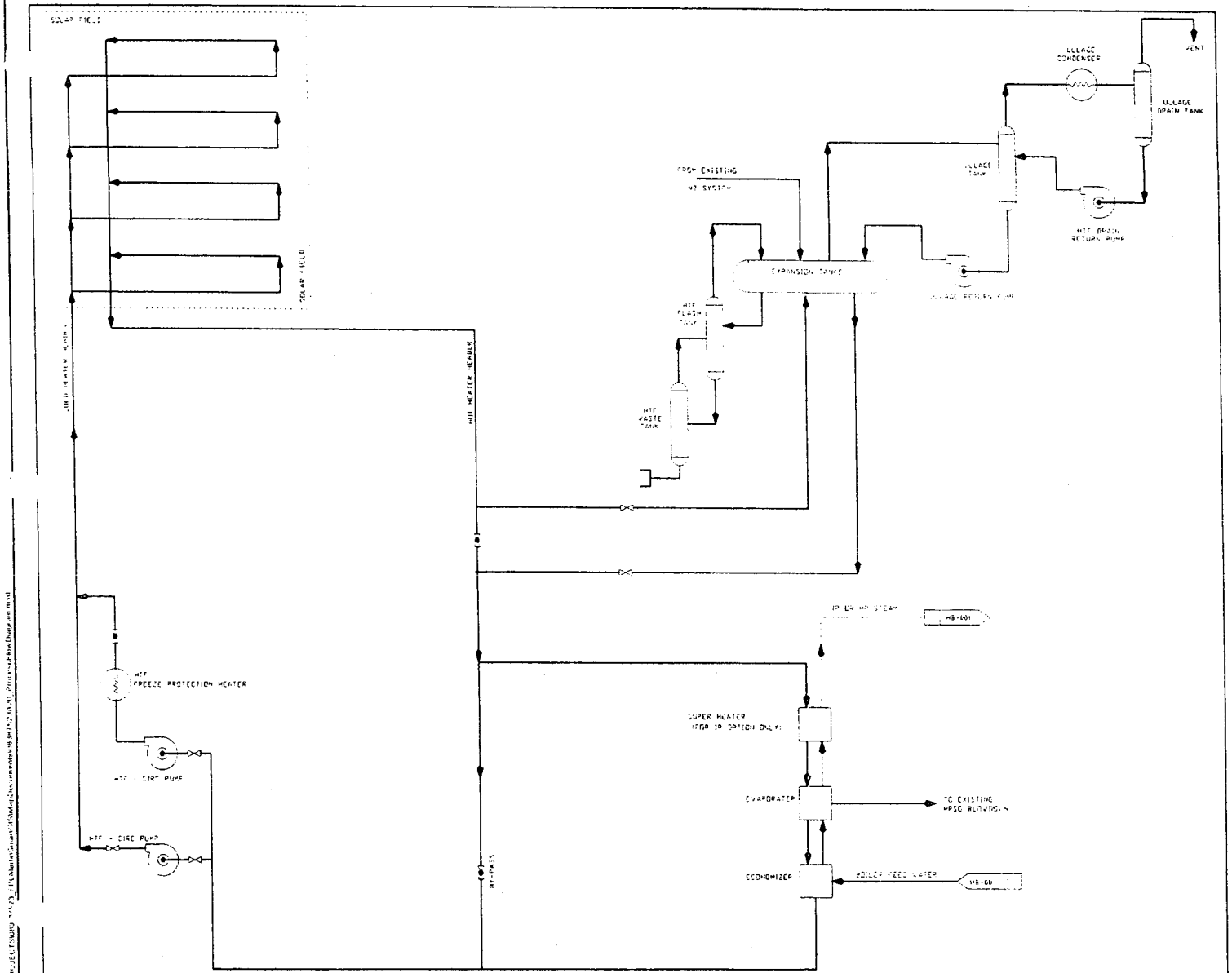
Q.

Please provide a one line diagram of the Martin Solar project which clearly shows where the steam generated by Martin Solar facility will be introduced into the existing steam cycle for Martin Power Plant Unit 8.

A.

The attached process flow diagram shows the two locations considered for introducing the Martin Solar facility steam into the existing steam cycle for Martin 8. FPL has selected the high pressure (HP) steam injection option. [redacted]





REFERENCE

1 Diagram, Worley Parsons, 2008

PROJECT	MARTIN SOLAR ENERGY CENTER
TITLE	PROCESS FLOW DIAGRAM
PROJECT No. 073-87665	SCALE AS SHOWN · REV 0
DESIGN KR 04/21/08	
DRS RL 04/23/08	
CHECK KR 04/23/08	FIGURE 3.1-2
REVIEW KR 04/23/08	

FPL

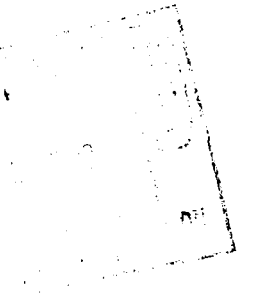
HEARING EXHIBIT - 00000658

Q.

When the Martin Solar facility is producing steam, will one or more of the existing combustion turbines that comprise the combined-cycle facility be shut down completely or continue to run at a reduced output?

A.

No, none of the combustion turbines will be shut down or run at a reduced output. All of the combustion turbines can continue to produce full output when the Martin Solar facility is producing steam. Steam produced by the Martin Solar facility will displace the Unit 8 duct burners, when running, or other less-efficient generation from FPL's system.



Q.
Please provide a sample calculation which demonstrates how FPL will calculate the fuel savings at the Martin facility as a result of the operation of the solar steam generator.

A.
The solar steam generation at Martin will displace more expensive energy from the system's marginal generating units. Fuel savings result from the reduction in fuel use at those marginal units. For any given period of time the fuel saving calculations must be performed with the use of a production cost model. FPL is using the PMAREA model for this purpose. However, as requested, FPL is providing a sample calculation of how these savings would be determined for a given hour.

Example (using representative data):

Solar steam generated energy at Martin for a peak hour = 75 MWH
Fuel cost of Martin solar steam generation = 0 $/MWH

Heat rate of marginal unit at this hour = 9,000 btu/kWh
Fuel price of energy at this marginal unit = 11.0 $/MMBtu (gas)
Price of energy at marginal unit = 9,000 * 11 / 1,000 = 99 $/MWH
Fuel cost savings for the peak hour = 99 * 75 = $ 7,425

Avoided fuel = 9,000 * 75 / 1,000 = 675 MMBtu of avoided gas

Q.
Please provide a side-by-side comparison of the revenue requirements for the Martin Plant Site with Martin Solar and without Martin Solar. Please provide a detailed explanation of all assumptions used in developing this comparison.

A.
Table 41-1, attached, shows the incremental revenue requirements of the Martin Solar Project. These incremental revenue requirements consist of increased capital and O&M costs partly offset by fuel and emission cost savings. Table 41-2 shows the assumptions used in the analysis.

In analyzing the economics of the Martin Solar Project, FPL compared the revenue requirements of two cases: one with the solar project, and one without it. For capital and O&M costs at the Martin Plant, FPL developed incremental capital and O&M cost impacts of the solar project. The capital and O&M revenue requirements associated with the existing plant were not quantified, as they were considered equal to both cases and would not impact the results of the comparison.

Fuel and emission savings were developed by running both cases with the PMAREA production costing model.

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Table 41-1
Page 1 of 1

Martin Solar Project

Annual Revenue Requirements, in thousand dollars

	Project Costs		System Costs (negative indicates savings)		Net Revenue Requirements
	Capital Revenue Requirements - Solar	FOM and Capital Replacement Costs	Fuel and VOM	Emissions	
2008	82	-	-	-	82
2009	11,789	-	-	-	11,789
2010	47,013	991	(2,000)	(8)	45,996
2011	79,150	2,437	(17,000)	(379)	64,209
2012	71,174	2,498	(18,000)	(481)	55,192
2013	65,755	2,561	(16,000)	(1,552)	50,763
2014	61,294	2,625	(14,000)	(1,597)	48,322
2015	57,554	2,690	(16,000)	(1,531)	42,713
2016	55,251	2,758	(16,000)	(1,899)	40,109
2017	53,668	2,827	(16,000)	(2,039)	38,455
2018	52,085	2,897	(18,000)	(2,600)	34,382
2019	50,502	2,970	(18,000)	(2,933)	32,539
2020	48,920	3,044	(19,000)	(2,660)	30,304
2021	47,338	3,120	(19,000)	(2,708)	28,750
2022	45,756	3,198	(19,000)	(3,004)	26,950
2023	44,174	3,278	(21,000)	(3,120)	23,332
2024	42,593	3,360	(20,000)	(3,387)	22,566
2025	41,012	3,444	(21,000)	(3,538)	19,918
2026	39,431	3,530	(21,000)	(3,244)	18,717
2027	37,851	3,618	(21,000)	(3,605)	16,864
2028	36,271	3,709	(22,000)	(3,922)	14,057
2029	34,691	3,802	(24,000)	(4,515)	9,978
2030	33,111	3,897	(25,000)	(4,845)	7,162
2031	31,532	3,994	(24,000)	(5,378)	6,148
2032	29,953	4,094	(26,000)	(5,135)	2,911
2033	28,374	4,196	(25,000)	(5,491)	2,079
2034	26,795	4,301	(29,000)	(6,546)	(4,450)
2035	25,217	4,409	(27,000)	(7,244)	(4,619)
2036	23,639	4,519	(30,000)	(6,479)	(8,321)
2037	22,063	4,632	(33,000)	(7,346)	(13,651)
2038	20,486	4,748	(31,000)	(9,733)	(15,500)
2039	18,909	4,866	(32,000)	(8,599)	(16,823)
2040	15,939	4,988	(35,000)	(10,025)	(24,098)
CPVRR	$530,628	$29,629	($180,649)	($25,421)	$354,187

HEARING EXHIBIT - 00000662

In-Service Year	2010
	Martin 75 MW Solar Trough
I. CONSTRUCTION ($1,000)	
Permit/Eng/Fab (months)	5
Construction Phase (months)	24
Project Total (months)	
Total Direct Cost	[redacted]
Total Indirect Cost	[redacted]
CWIP	
Plant Demolition	
Land, Plant Site	
Total Other Cost	[redacted]
Grand Total Cost (In Service Year)	**$527,966**
DOLLARS/KW	**$7,040**
II. PLANT CHARACTERISTICS (Unit Average)	
Net Sum 95FCapability (mw) - Base	75
III. OPERATION COSTS	2009
FOM ($M/yr)	[redacted]
VOM ($M/yr)	
Capital Replacement ($M/yr)	
TOTAL O&M	[redacted]
IV. EMISSION RATES	
NOx Emission Rates (lb/mmbtu)	0.000
CO Emission Rates (lb/mmbtu)	0.000
SO2 Emission Rates (lb/mmbtu)	0.000
PM10 (lb/mmbtu)	0.000
CO2 (lb/mmbtu)	0
Mecury, Hg (lb/Tbtu) (T=trillion)	0.000
VI. SPENDING CURVES (1,000) $ (not including CWIP)	In Service
Year 2012	
Year 2011	$4,717
Year 2010	$243,849
Year 2009	$210,006
Year 2008	$17,641
Year 2007	$68
VII. NOTES:	
Start of Spending Curve	December-07
Start of Constuction Date	January-09
End of Construction Date	December-10
In-Service Date	December-10

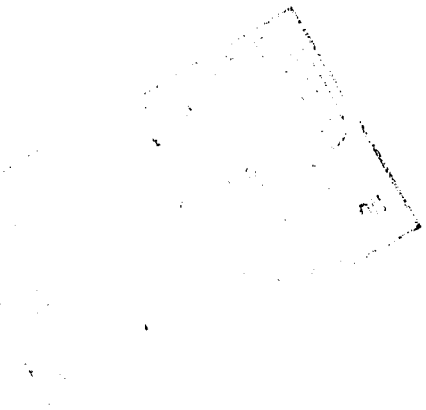
Table 41-2

Q.

Please describe or explain what will be the efficiency of the PV solar panels which will be used respectively in DeSoto and Space Coast PV solar facilities.

A.

The conversion efficiency of the PV solar panels used at both the DeSoto and the Space Coast PV facilities is expected to be 18.7%.



Q.

For each of FPL's PV Solar Projects, please describe or explain:

a. Whether some form of Tracker system will be used;
b. What are the benefits and/or drawbacks of including/not including such a system?

A.
a. At the DeSoto facility a single-axis tracking system will be employed. At the Space Coast facility a fixed tilt support system will be used.

b. The benefit of including a single-axis tracking system is that it will automatically track the movement of the sun throughout the day to optimize the capture of the sun's energy. In order to deploy and demonstrate the two different technologies, FPL determined that the DeSoto location was better suited for the Tracker and the Space Coast for the Fixed system. The drawback of the Tracker system is its higher initial cost compared to a fixed system.

Q.
Please explain the difference in capacity factors for Desoto Solar and Space Coast Solar (i.e. location, tracking, etc).

A.
The capacity factor for DeSoto is expected to be approximately 23% and for Space Coast 20%. The improved capacity at DeSoto is a result of (1) the installation of a PV tracker control system for positioning of the panels to optimize solar collection compared with a fixed tilt PV system at Space Coast, and (2) the greater solar irradiation (kwh/m2/day) at the DeSoto location than at the Space Coast location.

Q.

Please provide the estimation of the hourly energy production, as stated in Section 366.92(4), Florida Statutes, for each of the three solar projects using the table below:

Time of the day	Martin Solar (kW)	DeSoto Solar (kW)	Space Coast Solar (kW)
1:00 am			
2:00 am			
3:00 am			
4:00 am			
5:00 am			
6:00 am			
7:00am			
8:00 am			
9:00 am			
10:00 am			
11:00 am			
12:00 am			
1:00 pm			
2:00 pm			
3:00 pm			
4:00 pm			
5:00 pm			
6:00 pm			
7:00 pm			
8:00 pm			
9:00 pm			
10:00 pm			
11:00 pm			
12:00 pm			

A.

See table 45-1 which shows estimated daily energy production for each of the three solar projects. These energy production patterns are based on an annual average, for the first in-service year.

Table 45-1

Time of the day	Martin Solar (kW)	DeSoto Solar (kW)	Space Coast Solar (kW)
1:00 AM	0	0	0
2:00 AM	0	0	0
3:00 AM	0	0	0
4:00 AM	0	0	0
5:00 AM	0	0	0
6:00 AM	178	0	0
7:00 AM	6464	1189	340
8:00 AM	23834	6704	1898
9:00 AM	36184	12708	3953
10:00 AM	42710	15508	5490
11:00 AM	44272	16473	6643
12:00 AM	47007	16170	6949
1:00 PM	46010	16046	6949
2:00 PM	45720	16073	6453
3:00 PM	44520	15938	5405
4:00 PM	38867	14683	3763
5:00 PM	30475	11772	2219
6:00 PM	15515	5799	921
7:00 PM	2496	903	146
8:00 PM	11	0	0
9:00 PM	0	0	0
10:00 PM	0	0	0
11:00 PM	0	0	0
12:00 PM	0	0	0

13

FPL's response to Staff's Fifth Set of Interrogatories (Nos. 46 - 48)

HEARING EXHIBIT - 00000669

Q.

Regarding the variance of the O&M cost of Project No. 19a described on page 7, line 13-17, of witness Dubin's testimony dated 08/04/08, please explain why three vendors rather than one as originally projected are being used to conduct repairs.

A.

FPL determined that the leaks needed to be repaired sooner than the original schedule contemplated and thus required additional vendor resources. This will allow FPL to implement a more proactive approach to avoid future leaks that should decrease future repair costs.

Q.

Regarding the O&M costs of Project No. 31 addressed on page 10, line 4-15, of witness Dubin's testimony and Form 42-5E filed on 08/04/08, please explain or describe the following:

a. Whether FPL has included the costs of the two actions FPL intends to undertake to help limit the compliance cost impact of potential revisions to the Phase II Rule which were described in FPL's Petition for Approval to Modify the Scope of its CWA 316(b) Phase II Rule Project filed on 03/31/08?

b. If the answer to the above question is "yes", how much has been included?

A.

Project number is 28. The answer is yes. We are forecasting to spend $50,000.

Q.

Regarding the leasing of NASC_KSC property related to the Space Coast Solar Project, please explain or describe:

a) How many MW (or KW) will the NASA PV Facility produce when it is completed and before the potential Phase II expansion?

b) What does FPL intend to use the optional 40 acres of FPL PV Facility Phase II leasing property specified in article 1.2 of the Enhanced Use Lease?

c) The "capital replacement costs" specified in article 3.2 of the Enhanced Use Lease.

d) What are the estimates of the capital replacement costs?

A.

a) FPL is currently in negotiations with the EPC contractor for the NASA PV facility, and therefore the exact size of the NASA PV system has not been determined. Our current estimate is that the capacity of the NASA PV facility will fall somewhere in the range of 600-800 kW before the potential Phase II expansion.

b) FPL has no current development plans for the additional 40 acres, but has retained the option for potential future expansion of renewable at the site.

c) Some pieces of equipment used in the solar PV facility have a life expectancy that is less than the life of the solar array, such as the inverters. As a result, this equipment will need to be replaced during the life of the project. The "capital replacement costs" are the costs associated with the purchase of this replacement equipment.

d) FPL's estimated 30 year O&M cost for the NASA PV Facility includes the capital replacement cost of approximately $160,000 each for the three inverters in the 12 to 15 year time frame.

14

FPL's response to Staff's Sixth Set of Interrogatories (Nos. 49 - 50)

HEARING EXHIBIT - 00000673

Q.

For each of the following items, please refer to FPL's August 29, 2008, filing and to the depreciation rates that were approved in Docket No. 050188-EI, Order No. PSC-05-0902-S-EI, issued September 14, 2005.

a. Form 42-4PE, p. 51 of 54, Project 03 – Continuous Emissions Monitoring, Cutler Common Account 31100, explain why the depreciation rate being used is 0.00%, instead of the approved rate of -0.2%.

b. Form 42-4PE, p. 51 of 54, Project 03 – Continuous Emissions Monitoring, Cutler Unit 5 Account 31200, explain why the depreciation rate being used is 0.20%, instead of the approved rate of -0.4%

c. Form 42-4PE, p. 51 of 54, Project 03 – Continuous Emissions Monitoring, Martin Unit 8 Account 34300, explain why the depreciation rate being used is 5.50%, instead of the approved rate of 5.8%

d. Form 42-8E, p. 53 of 54, Project 23 – Spill Prevention Clean-up and Countermeasures, Cutler Common Account 31400, explain why the depreciation rate being used is 0.00%, instead of the approved rate of -3.1%.

e. Form 42-8E, p. 53 of 54, Project 23 – Spill Prevention Clean-up and Countermeasures, Cutler Unit 5 Account 31200, explain why the depreciation rate being used is 0.20%, instead of the approved rate of -1.2%.

f. Form 42-8E, p. 53 of 54, Project 23 – Spill Prevention Clean-up and Countermeasures, Martin Unit 8 Account 34300, explain why the depreciation rate being used is 5.50%, instead of the approved rate of 5.8%.

g. For each item a. through f., if the correct depreciation rate is not being used, provide the correct depreciation calculation.

A.

a. Cutler Common Account 31100 has been fully recovered in base rates. Rather than reverse depreciation on the assets at this plant acct/location which have been fully recovered, or overrecovered, and since Cutler Common, as a whole, has been fully recovered, FPL has ceased depreciation entirely until such time as the asset again has a positive net book value (i.e., plant in service exceeds the reserve balance).

b. Rather than reverse depreciation on the assets at this plant acct/location which have not been fully recovered, and since Cutler Unit 5, as a whole has not yet been fully recovered, the depreciation rate that is currently being used is the composite remaining life rate for Cutler Unit 5.

c. The rate used for Martin Unit 8 account 34300 is what was approved in Order PSC-05-0821-PAA-EI, Docket No. 050300-EI, issued 8/11/05.

d. Cutler Common Account 31400 has been fully recovered in base rates. See the company response to Part a above for explanation of rate.

e. Cutler Unit 5 account 31400 (the question erroneously mentions account 31200) has not been fully recovered. See the company response to Part b above for explanation of rate.

f. See the response to Part c above.

g. Not applicable

Q.

Please refer to FPL's August 29, 2008, filing, Form 42-8E, p. 52 of 54, Project 12 – Scherer Discharge Pipeline. What is the approved depreciation rate for Scherer Common Account 31000? Provide the number of the Order in which it was approved.

A.

There is no approved depreciation rate for Scherer Common . This account is Land & Land Rights and is not depreciable.

15

FPL's response to Staff's Seventh Set of Interrogatories (No. 51)

HEARING EXHIBIT - 00000677

Q.
Please complete the following three tables.

A.
Please see attachment I.

Martin Solar Project

Annual Revenue Requirements, in thousand dollars

	Revenue Requirements - Fixed Costs					Revenue Requirements- Variable Costs (negative indicates savings)					Total Revenue Requirements -
	Capital Revenue Requirements - Solar	FOM and Capital Replacement Costs	Total Fixed Revenue Requirements	Present Value	Cumulative Present Value	System Fuel and VOM	System Emissions	Total Variable Revenue Requirements	Present Value	Cumulative Present Value	Cumulative Present Value
2008	82	-	82	82	82	-	-	-	-	-	82
2009	11,789	-	11,789	10,881	10,963	-	-	-	-	-	10,963
2010	47,013	991	48,004	40,892	51,854	(2,000)	(8)	(2,008)	(1,710)	(1,710)	50,144
2011	79,150	2,437	81,588	64,145	115,999	(17,000)	(379)	(17,379)	(13,663)	(15,374)	100,626
2012	71,174	2,498	73,673	53,459	169,458	(18,000)	(481)	(18,481)	(13,410)	(28,784)	140,674
2013	65,755	2,561	68,316	45,752	215,211	(16,000)	(1,552)	(17,552)	(11,755)	(40,539)	174,672
2014	61,294	2,625	63,919	39,510	254,721	(14,000)	(1,597)	(15,597)	(9,641)	(50,180)	204,541
2015	57,554	2,690	60,244	34,369	289,090	(16,000)	(1,531)	(17,531)	(10,002)	(60,182)	228,908
2016	55,251	2,758	58,009	30,544	319,634	(16,000)	(1,899)	(17,899)	(9,425)	(69,606)	250,028
2017	53,668	2,827	56,494	27,455	347,089	(16,000)	(2,039)	(18,039)	(8,767)	(78,373)	268,716
2018	52,085	2,897	54,982	24,661	371,750	(18,000)	(2,600)	(20,600)	(9,240)	(87,613)	284,137
2019	50,502	2,970	53,472	22,136	393,886	(18,000)	(2,933)	(20,933)	(8,666)	(96,278)	297,608
2020	48,920	3,044	51,964	19,854	413,740	(19,000)	(2,660)	(21,660)	(8,276)	(104,554)	309,186
2021	47,338	3,120	50,458	17,793	431,533	(19,000)	(2,708)	(21,708)	(7,655)	(112,209)	319,324
2022	45,756	3,198	48,954	15,933	447,466	(19,000)	(3,004)	(22,004)	(7,161)	(119,371)	328,096
2023	44,174	3,278	47,452	14,254	461,721	(21,000)	(3,120)	(24,120)	(7,245)	(126,616)	335,104
2024	42,593	3,360	45,953	12,740	474,461	(20,000)	(3,387)	(23,387)	(6,484)	(133,100)	341,361
2025	41,012	3,444	44,456	11,376	485,836	(21,000)	(3,538)	(24,538)	(6,279)	(139,379)	346,457
2026	39,431	3,530	42,961	10,146	495,982	(21,000)	(3,244)	(24,244)	(5,726)	(145,105)	350,878
2027	37,851	3,618	41,469	9,039	505,022	(21,000)	(3,605)	(24,605)	(5,363)	(150,468)	354,554
2028	36,271	3,709	39,979	8,043	513,065	(22,000)	(3,922)	(25,922)	(5,215)	(155,683)	357,382
2029	34,691	3,802	38,492	7,147	520,212	(24,000)	(4,515)	(28,515)	(5,295)	(160,978)	359,234
2030	33,111	3,897	37,008	6,342	526,554	(25,000)	(4,845)	(29,845)	(5,115)	(166,092)	360,462
2031	31,532	3,994	35,526	5,619	532,173	(24,000)	(5,378)	(29,378)	(4,647)	(170,739)	361,434
2032	29,953	4,094	34,047	4,970	537,143	(26,000)	(5,135)	(31,135)	(4,545)	(175,284)	361,859
2033	28,374	4,196	32,570	4,388	541,531	(25,000)	(5,491)	(30,491)	(4,108)	(179,392)	362,139
2034	26,795	4,301	31,096	3,867	545,398	(29,000)	(6,546)	(35,546)	(4,420)	(183,813)	361,586
2035	25,217	4,409	29,626	3,400	548,798	(27,000)	(7,244)	(34,244)	(3,930)	(187,743)	361,056
2036	23,639	4,519	28,158	2,983	551,781	(30,000)	(6,479)	(36,479)	(3,864)	(191,607)	360,174
2037	22,063	4,632	26,695	2,610	554,391	(33,000)	(7,346)	(40,346)	(3,944)	(195,552)	358,839
2038	20,486	4,748	25,233	2,277	556,668	(31,000)	(9,733)	(40,733)	(3,676)	(199,227)	357,441
2039	18,909	4,866	23,775	1,980	558,648	(32,000)	(8,599)	(40,599)	(3,381)	(202,608)	356,040
2040	15,939	4,988	20,927	1,609	560,257	(35,000)	(10,025)	(45,025)	(3,461)	(206,069)	354,187

CPVRR	530,628	29,629
	total fixed	560,257

CPVRR	(180,649)	(25,421)
	total variable	($206,069)

total CPVRR 354,187

HEARING EXHIBIT - 00000679

De Soto Solar Project

Annual Revenue Requirements, in thousand dollars

	Revenue Requirements - Fixed Costs					Revenue Requirements- Variable Costs (negative indicates savings)					Total Revenue Requirements -
	Capital Revenue Requirements - Solar	FOM and Capital Replacement Costs	Total Fixed Revenue Requirements	Present Value	Cumulative Present Value	System Fuel and VOM	System Emissions	Total Variable Revenue Requirements	Present Value	Cumulative Present Value	Cumulative Present Value
2008	29	-	29	29	29	-	-	-	-	-	29
2009	11,962	113	12,075	11,144	11,174	(8,000)	(2)	(8,002)	(7,386)	(7,386)	3,788
2010	28,892	1,387	30,279	25,793	36,966	(6,000)	(143)	(6,143)	(5,233)	(12,619)	24,348
2011	26,065	1,421	27,486	21,610	58,576	(6,000)	(210)	(6,210)	(4,882)	(17,501)	41,076
2012	24,128	1,457	25,585	18,565	77,142	(6,000)	(188)	(6,188)	(4,491)	(21,991)	55,150
2013	22,527	1,493	24,020	16,087	93,229	(5,000)	(516)	(5,516)	(3,694)	(25,686)	67,543
2014	21,178	1,531	22,709	14,037	107,266	(5,000)	(513)	(5,513)	(3,408)	(29,093)	78,172
2015	20,331	1,569	21,900	12,494	119,760	(5,000)	(614)	(5,614)	(3,203)	(32,296)	87,464
2016	19,733	1,608	21,341	11,237	130,997	(5,000)	(682)	(5,682)	(2,992)	(35,288)	95,709
2017	19,135	1,648	20,784	10,100	141,097	(6,000)	(722)	(6,722)	(3,267)	(38,555)	102,543
2018	18,538	1,690	20,228	9,073	150,170	(5,000)	(917)	(5,917)	(2,654)	(41,208)	108,962
2019	17,941	1,732	19,673	8,144	158,314	(6,000)	(957)	(6,957)	(2,880)	(44,088)	114,226
2020	17,343	1,775	19,118	7,305	165,619	(7,000)	(848)	(7,848)	(2,999)	(47,087)	118,532
2021	16,746	1,820	18,566	6,547	172,166	(6,000)	(961)	(6,961)	(2,455)	(49,542)	122,624
2022	16,149	1,865	18,014	5,863	178,028	(6,000)	(1,022)	(7,022)	(2,286)	(51,827)	126,201
2023	15,552	1,912	17,464	5,246	183,274	(6,000)	(1,051)	(7,051)	(2,118)	(53,945)	129,329
2024	14,961	1,960	16,921	4,691	187,966	(6,000)	(1,228)	(7,228)	(2,004)	(55,949)	132,016
2025	14,384	2,009	16,392	4,195	192,160	(6,000)	(1,181)	(7,181)	(1,837)	(57,787)	134,374
2026	13,813	2,059	15,872	3,748	195,909	(7,000)	(1,169)	(8,169)	(1,929)	(59,716)	136,193
2027	13,242	2,110	15,353	3,346	199,255	(7,000)	(1,175)	(8,175)	(1,782)	(61,498)	137,757
2028	12,672	2,163	14,835	2,984	202,240	(7,000)	(1,203)	(8,203)	(1,650)	(63,148)	139,091
2029	12,101	2,217	14,318	2,659	204,898	(7,000)	(1,462)	(8,462)	(1,571)	(64,719)	140,179
2030	11,531	2,272	13,803	2,366	207,264	(7,000)	(1,981)	(8,981)	(1,539)	(66,258)	141,005
2031	10,961	2,329	13,290	2,102	209,366	(8,000)	(1,894)	(9,894)	(1,565)	(67,823)	141,542
2032	10,391	2,388	12,778	1,865	211,231	(8,000)	(1,863)	(9,863)	(1,440)	(69,263)	141,968
2033	9,820	2,447	12,268	1,653	212,884	(7,000)	(1,850)	(8,850)	(1,192)	(70,456)	142,428
2034	9,250	2,508	11,759	1,462	214,346	(7,000)	(1,905)	(8,905)	(1,107)	(71,563)	142,783
2035	8,680	2,571	11,252	1,291	215,638	(7,000)	(2,415)	(9,415)	(1,081)	(72,644)	142,994
2036	8,111	2,635	10,746	1,138	216,776	(7,000)	(2,160)	(9,160)	(970)	(73,614)	143,162
2037	7,542	2,701	10,243	1,001	217,777	(7,000)	(2,449)	(9,449)	(924)	(74,538)	143,240
2038	6,972	2,769	9,741	879	218,656	(7,000)	(3,244)	(10,244)	(924)	(75,462)	143,194
2039	5,920	2,838	8,758	729	219,386	(7,000)	(2,580)	(9,580)	(798)	(76,260)	143,126
2040	372	2,909	3,281	252	219,638	-		-	-	(76,260)	143,378
CPVRR	201,566	18,072			CPVRR	(67,654)	(8,606)		total CPVRR		143,378
	total fixed	219,638				total variable	($76,260)				

HEARING EXHIBIT - 00000680

Space Coast Solar Project

Annual Revenue Requirements, in thousand dollars

	Revenue Requirements - Fixed Costs					Revenue Requirements- Variable Costs (negative indicates savings)					Total Revenue Requirements -
	Capital Revenue Requirements - Solar	FOM and Capital Replacement Costs	Total Fixed Revenue Requirements	Present Value	Cumulative Present Value	System Fuel and VOM	System Emissions	Total Variable Revenue Requirements	Present Value	Cumulative Present Value	Cumulative Present Value
2008	37	-	37	37	37	-	-	-	-	-	37
2009	1,625	-	1,625	1,500	1,537	-	-	-	-	-	1,537
2010	9,903	275	10,178	8,670	10,207	(1,000)	(17)	(1,017)	(866)	(866)	9,341
2011	13,217	563	13,780	10,834	21,041	(2,000)	(63)	(2,063)	(1,622)	(2,488)	18,553
2012	11,912	577	12,489	9,063	30,104	(2,000)	(38)	(2,038)	(1,479)	(3,967)	26,137
2013	11,018	592	11,609	7,775	37,879	(1,000)	(181)	(1,181)	(791)	(4,758)	33,121
2014	10,279	606	10,885	6,728	44,607	(2,000)	(155)	(2,155)	(1,332)	(6,090)	38,517
2015	9,657	622	10,278	5,864	50,471	(1,000)	(186)	(1,186)	(676)	(6,767)	43,704
2016	9,266	637	9,903	5,214	55,685	(2,000)	(208)	(2,208)	(1,163)	(7,929)	47,756
2017	8,990	653	9,643	4,686	60,372	(1,000)	(253)	(1,253)	(609)	(8,538)	51,833
2018	8,715	669	9,384	4,209	64,581	(2,000)	(368)	(2,368)	(1,062)	(9,600)	54,980
2019	8,439	686	9,126	3,778	68,358	(2,000)	(329)	(2,329)	(964)	(10,565)	57,794
2020	8,164	703	8,867	3,388	71,746	(2,000)	(286)	(2,286)	(873)	(11,438)	60,309
2021	7,889	721	8,610	3,036	74,783	(2,000)	(302)	(2,302)	(812)	(12,250)	62,533
2022	7,614	739	8,352	2,718	77,501	(2,000)	(399)	(2,399)	(781)	(13,031)	64,470
2023	7,338	757	8,096	2,432	79,933	(2,000)	(348)	(2,348)	(705)	(13,736)	66,197
2024	7,063	776	7,840	2,173	82,106	(2,000)	(440)	(2,440)	(676)	(14,412)	67,694
2025	6,791	796	7,587	1,941	84,048	(2,000)	(425)	(2,425)	(621)	(15,033)	69,015
2026	6,525	816	7,340	1,734	85,781	(2,000)	(588)	(2,588)	(611)	(15,644)	70,137
2027	6,261	836	7,097	1,547	87,328	(2,000)	(422)	(2,422)	(528)	(16,172)	71,156
2028	5,998	857	6,855	1,379	88,707	(2,000)	(376)	(2,376)	(478)	(16,650)	72,057
2029	5,735	878	6,613	1,228	89,935	(2,000)	(410)	(2,410)	(447)	(17,098)	72,838
2030	5,471	900	6,372	1,092	91,027	(2,000)	(549)	(2,549)	(437)	(17,534)	73,493
2031	5,208	923	6,131	970	91,997	(2,000)	(870)	(2,870)	(454)	(17,988)	74,009
2032	4,945	946	5,891	860	92,857	(3,000)	(830)	(3,830)	(559)	(18,547)	74,309
2033	4,682	969	5,651	761	93,618	(3,000)	(716)	(3,716)	(501)	(19,048)	74,570
2034	4,419	994	5,413	673	94,291	(2,000)	(669)	(2,669)	(332)	(19,380)	74,911
2035	4,156	1,019	5,174	594	94,885	(2,000)	(520)	(2,520)	(289)	(19,669)	75,216
2036	3,893	1,044	4,937	523	95,408	(2,000)	(864)	(2,864)	(303)	(19,973)	75,436
2037	3,630	1,070	4,700	460	95,868	(2,000)	(979)	(2,979)	(291)	(20,264)	75,604
2038	3,367	1,097	4,464	403	96,270	(2,000)	(1,298)	(3,298)	(298)	(20,561)	75,709
2039	3,104	1,124	4,229	352	96,623	(2,000)	(1,146)	(3,146)	(262)	(20,823)	75,799
2040	1,534	1,152	2,686	206	96,829	(1,000)	(668)	(1,668)	(128)	(20,952)	75,877
CPVRR	89,945	6,884			CPVRR	(17,896)	(3,055)		total CPVRR		75,877
	total fixed	96,829				total variable	($20,952)				

HEARING EXHIBIT - 00000681

16

FPL's response to Staff's Eighth Set of Interrogatories (Nos. 52 - 56)

HEARING EXHIBIT - 00000682

Q.

In the response to staff's third set of interrogatories, question No. 23, regarding FPL's lease of property at NASA-KSC, FPL stated that "while the lease payment consists of non-monetary consideration, the total of the non-monetary consideration to NASA does not exceed the amount FPL would have paid to lease the property solely for monetary consideration." Please describe or explain the benefits that FPL and its rate payers would obtain for electing the non-monetary consideration as the leasing payment versus only monetary consideration.

A.

From a narrow economic perspective, there is no economic benefit or detriment to FPL or its customers in the use of non-monetary consideration versus monetary consideration for the land lease because the value of the non-monetary consideration to NASA is equivalent to the amount that would have been paid to NASA using only monetary consideration.

However, there are a number of indirect benefits associated with this approach. By providing NASA with an in-kind payment in the form of a separate state-of-the latest photovoltaic (PV) system, FPL is enabling the construction of additional renewable generation in Florida that otherwise likely would not be constructed with these funds by NASA. This additional PV facility will be a zero-greenhouse gas emitting facility, and the energy it creates will displace such energy otherwise coming from fossil fuel-sourced generation. Since NASA is an agency supported by taxpayer dollars, there is also a public benefit from enhancing renewable energy usage at the facility.

In addition, having this facility as part of NASA's power generation has the potential to further enhance public awareness of renewables and could provide research and educational opportunities for NASA as well as the public. This facility will also help to encourage other federal facilities to develop similar renewable projects nationwide. NASA's ability to collect data and conduct PV research could also potentially advance the application of solar PV in outer space.

Q.

Please use the following table to provide detailed comparisons of the NASA-KSC Lease between non-monetary consideration and the monetary consideration if it were provided in lieu of the non monetary consideration:

A.

FPL's NASA KSC Lease	Length of the Lease (years)	*Non-Monetary Consideration*			Monetary Consideration
		NASA PV Facility (details of the projects/ items to be included)	Capital Costs ($ Amount)	O&M Cost plus the Replacement Costs ($ Amount)	($ Amount)
Phase I	30	Approx. 750 kW still under development with final capacity TBD	Net Present Value (NPV) $6,359,027	NPV $400,000	NPV $6,759,027
Potential Extension	20	TBD	TBD	TBD	TBD
Sub-total					
Phase II	30 if exercised	TBD	TBD	TBD	TBD
Potential Extension	20 if exercised				
Sub-total					
Grand Total	TBD	TBD	TBD	TBD	TBD

Q.

Please refer to FPL's responses to staff's fourth set of interrogatories, question No. 34, Table 1-1 on page 1 & 2 of 3. Please describe or explain why the Installed Costs ($/kw) and the Overnight Construction Costs ($/kw) for the Space Coast Solar Energy Center are both higher than that of the DeSoto Solar Energy Center, given the fact that (a) both the Incremental Gross Capacity and the Incremental Net Capacity of the Space Coast Solar Center (10 MW) are less than that of the Desoto Solar Center (25 MW); (b) a solar center with tracking systems (such as the DeSoto center) is generally more expensive than a solar center with fixed array systems (such as the Space Coast Solar); and (c) the costs of the Space Coast Solar Center includes net present value of the long term land lease (refer to footnote 2 in the table).

A.

The Installed and Overnight costs for the Space Coast Solar Energy Center (SCSEC) are higher than those for the DeSoto Solar Energy Center (DSEC) for two primary reasons.

First, as noted in (a) above, the SCSEC is a smaller facility, and therefore can not achieve the same economies of scale as the DSEC project. In other words, all else being equal, it is typical for unit price to decrease (e.g. $/kw) as project size increases due to the ability to negotiate better pricing when purchasing more equipment and also the ability to spread the development, engineering, interconnection, and construction costs over a larger number of kilowatts. In addition, as noted in (c) above, the unit cost for SCSEC is higher because it includes the value of the land lease, which is not required for the DSEC.

With respect to item (b) above, it is true that tracking systems are generally more expensive than fixed systems. In the case of SCSEC, the relative equipment savings are reflected in the overall cost. If the SCSEC were to have a tracking system, the overall cost for that facility would be higher than the current price.

Q.

For purposes of determining the reasonableness and prudence of the costs associated with the Space Coast Solar project, please explain in detail how FPL has "used reasonable and customary industry practices in the design, procurement, and construction of the project in a cost-effective manner appropriate to the location of the facility," as section 366,92(4) requires. In particular, please explain how the non-monetary compensation for the NASA-KSC Lease is a "reasonable and customary practice."

A.

FPL has used reasonable and customary industry practices in the design, procurement and construction of the project, and has negotiated to secure favorable pricing and terms for its customers. For example, FPL has entered into a turnkey EPC contract for the Space Coast PV solar project with a highly qualified supplier and contractor experienced in utility-scale PV projects. As part of the process, FPL followed a well-defined request for information ("RFI") process which was initially conducted in 2007 with responses from 26 international and domestic companies involved in the development, manufacturing, and construction of utility-scale PV systems and projects. In February of 2008 a request for proposals ("RFP") was issued which resulted in responses from 8 companies of which 4 provided conforming proposals after obtaining bid clarifications and conducting an initial screening evaluation. A detailed bid evaluation on the conforming proposals identified two low bidders. Initial negotiations with the two companies was conducted which resulted in a final selection.

FPL is using trained and qualified employees with extensive experience in designing, procuring, and constructing utility facilities to oversee the project management aspects of the PV project.

With regard to the non-monetary consideration aspect of this project, FPL has documented a favorable in-kind exchange with the overall cost being equivalent to that for monetary consideration. In this regard, the actual means of payment is not relevant in that the overall amount to be paid is the same. Please see FPL's response to Interrogatory No. 52 for a discussion of benefits to customers from FPL's form of compensation for the project.

Q.

Please provide a levelized cost (in $/kWh) for various capacity factors for each solar project. Please provide the raw data and a chart depicting this information.

A.

The levelized costs for each of the three solar projects are shown in the attached table and chart. Costs were levelized over a 30-year life. Capacity factors ranging from 5% to 30% are provided in $/MWH. The information that was used in this analysis has been shown in more detail in the response to Question 51, Staff's Seventh Set of Interrogatories.

Please note that the costs shown here do not include the system benefits of fuel and emission cost savings.

Martin Solar Project

	Annual Revenue Requirements- Capital and O&M $000	Annual Revenue Requirements- Capital and O&M $000 levelized	Net Cost - Levelized at 5% Capacity factor $/MWH	at 10% Capacity factor $/MWH	at 15% Capacity factor $/MWH	at 20% Capacity factor $/MWH	at 25% Capacity factor $/MWH	at 30% Capacity factor $/MWH
2008	82	-	-	-	-	-	-	-
2009	11,789	-	-	-	-	-	-	-
2010	48,004	55,278	1,683	841	561	421	337	280
2011	81,588	55,278	1,683	841	561	421	337	280
2012	73,673	55,278	1,683	841	561	421	337	280
2013	68,316	55,278	1,683	841	561	421	337	280
2014	63,919	55,278	1,683	841	561	421	337	280
2015	60,244	55,278	1,683	841	561	421	337	280
2016	58,009	55,278	1,683	841	561	421	337	280
2017	56,494	55,278	1,683	841	561	421	337	280
2018	54,982	55,278	1,683	841	561	421	337	280
2019	53,472	55,278	1,683	841	561	421	337	280
2020	51,964	55,278	1,683	841	561	421	337	280
2021	50,458	55,278	1,683	841	561	421	337	280
2022	48,954	55,278	1,683	841	561	421	337	280
2023	47,452	55,278	1,683	841	561	421	337	280
2024	45,953	55,278	1,683	841	561	421	337	280
2025	44,456	55,278	1,683	841	561	421	337	280
2026	42,961	55,278	1,683	841	561	421	337	280
2027	41,469	55,278	1,683	841	561	421	337	280
2028	39,979	55,278	1,683	841	561	421	337	280
2029	38,492	55,278	1,683	841	561	421	337	280
2030	37,008	55,278	1,683	841	561	421	337	280
2031	35,526	55,278	1,683	841	561	421	337	280
2032	34,047	55,278	1,683	841	561	421	337	280
2033	32,570	55,278	1,683	841	561	421	337	280
2034	31,096	55,278	1,683	841	561	421	337	280
2035	29,626	55,278	1,683	841	561	421	337	280
2036	28,158	55,278	1,683	841	561	421	337	280
2037	26,695	55,278	1,683	841	561	421	337	280
2038	25,233	55,278	1,683	841	561	421	337	280
2039	23,775	55,278	1,683	841	561	421	337	280
2040	20,927	55,278						

HEARING EXHIBIT - 00000688

De Soto Solar Project

	Annual Revenue Requirements- Capital and O&M $000	Annual Revenue Requirements- Capital and O&M $000 levelized	Net Cost - Levelized at 5% Capacity factor $/MWH	at 10% Capacity factor $/MWH	at 15% Capacity factor $/MWH	at 20% Capacity factor $/MWH	at 25% Capacity factor $/MWH	at 30% Capacity factor $/MWH
2008	29	-	-	-	-	-	-	-
2009	12,075	-	-	-	-	-	-	-
2010	30,279	21,671	1,979	990	660	495	396	236
2011	27,486	21,671	1,979	990	660	495	396	236
2012	25,585	21,671	1,979	990	660	495	396	236
2013	24,020	21,671	1,979	990	660	495	396	236
2014	22,709	21,671	1,979	990	660	495	396	236
2015	21,900	21,671	1,979	990	660	495	396	236
2016	21,341	21,671	1,979	990	660	495	396	236
2017	20,784	21,671	1,979	990	660	495	396	236
2018	20,228	21,671	1,979	990	660	495	396	236
2019	19,673	21,671	1,979	990	660	495	396	236
2020	19,118	21,671	1,979	990	660	495	396	236
2021	18,566	21,671	1,979	990	660	495	396	236
2022	18,014	21,671	1,979	990	660	495	396	236
2023	17,464	21,671	1,979	990	660	495	396	236
2024	16,921	21,671	1,979	990	660	495	396	236
2025	16,392	21,671	1,979	990	660	495	396	236
2026	15,872	21,671	1,979	990	660	495	396	236
2027	15,353	21,671	1,979	990	660	495	396	236
2028	14,835	21,671	1,979	990	660	495	396	236
2029	14,318	21,671	1,979	990	660	495	396	236
2030	13,803	21,671	1,979	990	660	495	396	236
2031	13,290	21,671	1,979	990	660	495	396	236
2032	12,778	21,671	1,979	990	660	495	396	236
2033	12,268	21,671	1,979	990	660	495	396	236
2034	11,759	21,671	1,979	990	660	495	396	236
2035	11,252	21,671	1,979	990	660	495	396	236
2036	10,746	21,671	1,979	990	660	495	396	236
2037	10,243	21,671	1,979	990	660	495	396	236
2038	9,741	21,671	1,979	990	660	495	396	236
2039	8,758	21,671	1,979	990	660	495	396	236
2040	3,281	21,671						

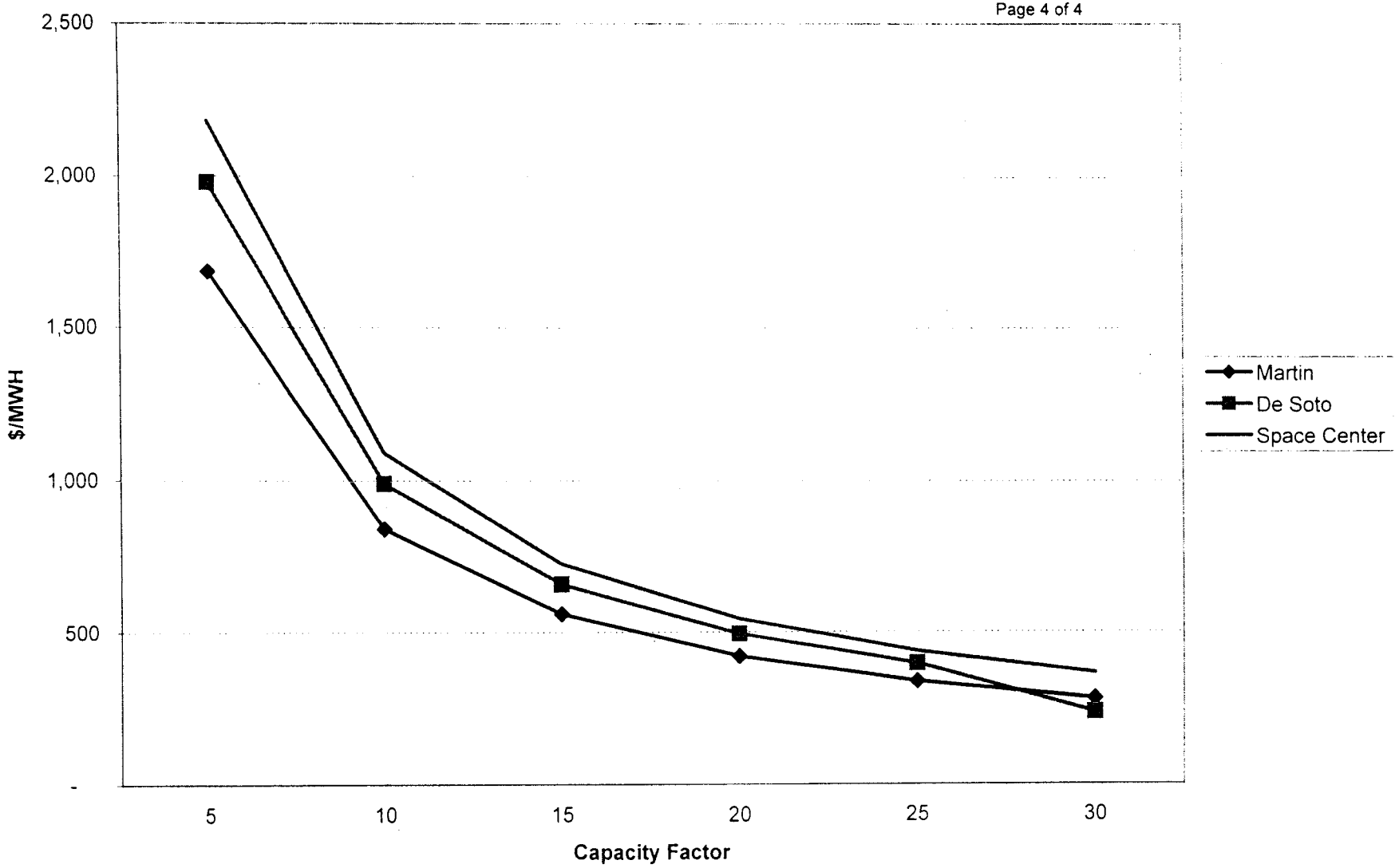
HEARING EXHIBIT - 00000689

Space Center Solar Project

	Annual Revenue Requirements- Capital and O&M $000	Annual Revenue Requirements- Capital and O&M $000 levelized	Net Cost - Levelized at 5% Capacity factor $/MWH	at 10% Capacity factor $/MWH	at 15% Capacity factor $/MWH	at 20% Capacity factor $/MWH	at 25% Capacity factor $/MWH	at 30% Capacity factor $/MWH
2008	37	-	-	-	-	-	-	-
2009	1,625	-	-	-	-	-	-	-
2010	10,178	9,554	2,181	1,091	727	545	436	364
2011	13,780	9,554	2,181	1,091	727	545	436	364
2012	12,489	9,554	2,181	1,091	727	545	436	364
2013	11,609	9,554	2,181	1,091	727	545	436	364
2014	10,885	9,554	2,181	1,091	727	545	436	364
2015	10,278	9,554	2,181	1,091	727	545	436	364
2016	9,903	9,554	2,181	1,091	727	545	436	364
2017	9,643	9,554	2,181	1,091	727	545	436	364
2018	9,384	9,554	2,181	1,091	727	545	436	364
2019	9,126	9,554	2,181	1,091	727	545	436	364
2020	8,867	9,554	2,181	1,091	727	545	436	364
2021	8,610	9,554	2,181	1,091	727	545	436	364
2022	8,352	9,554	2,181	1,091	727	545	436	364
2023	8,096	9,554	2,181	1,091	727	545	436	364
2024	7,840	9,554	2,181	1,091	727	545	436	364
2025	7,587	9,554	2,181	1,091	727	545	436	364
2026	7,340	9,554	2,181	1,091	727	545	436	364
2027	7,097	9,554	2,181	1,091	727	545	436	364
2028	6,855	9,554	2,181	1,091	727	545	436	364
2029	6,613	9,554	2,181	1,091	727	545	436	364
2030	6,372	9,554	2,181	1,091	727	545	436	364
2031	6,131	9,554	2,181	1,091	727	545	436	364
2032	5,891	9,554	2,181	1,091	727	545	436	364
2033	5,651	9,554	2,181	1,091	727	545	436	364
2034	5,413	9,554	2,181	1,091	727	545	436	364
2035	5,174	9,554	2,181	1,091	727	545	436	364
2036	4,937	9,554	2,181	1,091	727	545	436	364
2037	4,700	9,554	2,181	1,091	727	545	436	364
2038	4,464	9,554	2,181	1,091	727	545	436	364
2039	4,229	9,554	2,181	1,091	727	545	436	364
2040	2,686	9,554						

HEARING EXHIBIT - 00000690

Levelized Costs of FPL Solar Projects



HEARING EXHIBIT - 00000691

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PEF's Response to Staff's Second Request for Production of Documents (No. 2)

HEARING EXHIBIT - 00000692

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No. 080007-EI
	Dated: July 31, 2008

PROGRESS ENERGY FLORIDA'S RESPONSE TO STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 2)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.350, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Second Request for Production of Documents (No. 2):

RESPONSE

2. **Please refer to the testimony and exhibits of Will Garrett dated April 2, 2008. Please provide a reconciliation and corrected pages 2, 10, 12, and 13 of forms 42-8E. Please cite all sources and include the rationale for using the particular capital structure and cost rates.**

Response:

Progress Energy believes that this request should refer to Form 42-8A instead of form 42-8E and that this request concerns the calculation of the return on equity and debt on pages 2, 10, 12, and 13 of Form 42-8A. The capital structure and cost rates in these calculations were provided in response to Staff's First Request for Production of Documents in Docket No. 080007-EI. The return on equity and debt can only be calculated for individual months because changes in the net investment during the year render a full year calculation of the return impossible. Also, there are true-ups to the return amounts in certain months for prior period corrections and retroactive in-service dates. The true-up amounts were calculated as the amount necessary to adjust the return to agree to the corrected schedules through the end of the month when the true-up was included. Progress Energy emphasizes that the corrected schedules were not used as the basis for any part of the schedule after that month.

Form 42-8A Page 2 sums the return on equity and debt for all Above Ground Storage Tank Secondary Containment projects for peaking load facilities. The calculation of the return for each facility appears on Exhibit WG-2, pages 2 - 6 and includes projects 4.1a - 4.1h. The return for Project 4.1c includes a true-up in January 2007 because the CWIP – Non-Interest Bearing and Net Investment amounts (Lines 4 & 5) were omitted for

HEARING EXHIBIT - 00000693

December 2006 in error and therefore the return was improperly calculated for that month in the 2006 True-Up Filing (Exhibit WG-2, Docket 070007). The return on equity true-up is an increase of $7,506 and the return on debt true-up is an increase of $1,372. Please see Attachment A for the corrected 2006 schedule. Project 4.1c also includes a return true-up in March 2007 because during the month the project was placed in service retroactively as of November 2006. The return on equity true-up is a decrease of $211 and the return on debt true-up is a decrease of $38. Please see Attachments B and C for the corrected 2006 and 2007 schedules as a result of this issue. Project 4.1d and Project 4.1h also include immaterial return on equity true-ups totaling a decrease of $90 and return on debt true-ups totaling a decrease of $17 due to other minor calculation errors.

Form 42-8A Page 10 is correct as filed.

Form 42-8A Page 12 includes a true-up to the return in June 2007 because the asset was placed in service that month retroactively as of January 2007. The return on equity true-up is a decrease of $827 and the return on debt true-up is a decrease of $151. Please see Attachment D for the corrected 2007 schedule.

Form 42-8A Page 13 includes a true-up to the return in July 2007 because the final part of that project was placed in service that month retroactively as of March 2007. The return on equity true-up is a decrease of $978 and the return on debt true-up is a decrease of $179. Please see Attachment E for the corrected 2007 schedule.

SERVED this 31st day of July, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko, Esquire
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

HEARING EXHIBIT - 00000694

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4c)
(In Dollars)

Base
20035307

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	
	c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other		-	-	-	-	-	-	-	-	-	-	-	-	
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	(3,216)	(3,327)	(3,438)	(3,549)	(3,660)	(3,772)	(3,883)	(3,994)	(4,105)	(4,216)	(4,327)	(4,438)	(4,549)	
4	CWIP - Non-Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Net Investment (Lines 2 + 3 + 4)	29,876	29,765	29,654	29,543	29,432	29,320	29,209	29,098	28,987	28,876	28,765	28,654	28,543	
6	Average Net Investment		29,821	29,709	29,598	29,487	29,376	29,265	29,154	29,043	28,931	28,820	28,709	28,598	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	277	276	275	274	273	272	271	270	269	268	267	266	3,260
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%	51	51	50	50	50	50	50	49	49	49	49	49	596
8	Investment Expenses														
	a. Depreciation	4.03%	111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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	0.018008	45	45	44	44	44	44	44	43	43	43	43	43	528
	e. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)		484	482	481	480	478	477	475	474	473	471	470	469	5,714
	a. Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand		484	482	481	480	478	477	475	474	473	471	470	469	5,714

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4d)
(In Dollars)

Peaking Est. in service date November 2006
20048125

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		-	-	83,493	172,936	55,368	104,180	27,054	18,527	-	28,984	-	220,000	708,521
	b. Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	
	c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other		-	-	-	-	-	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Less: Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	CWIP - Non-Interest Bearing	905,709	905,709	905,709	988,202	1,161,138	1,216,506	1,320,686	1,347,740	1,366,247	1,366,247	1,394,230	1,394,230	1,614,230	
5	Net Investment (Lines 2 + 3 + 4)	905,709	905,709	905,709	988,202	1,161,138	1,216,506	1,320,686	1,347,740	1,366,247	1,366,247	1,394,230	1,394,230	1,614,230	
6	Average Net Investment		905,709	905,709	947,455	1,075,670	1,189,822	1,268,596	1,334,193	1,357,993	1,366,247	1,380,238	1,394,230	1,504,230	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	8,423	8,423	8,811	10,004	11,065	11,807	12,417	12,629	12,715	12,841	12,966	13,968	136,092
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%	1,540	1,540	1,611	1,829	2,023	2,158	2,270	2,308	2,324	2,347	2,370	2,557	24,877
8	Investment Expenses														
	a. Depreciation	3.38%	-	-	-	-	-	-	-	-	-	-	-	-	-
	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	0.015717	-	-	-	-	-	-	-	-	-	-	-	-	-
	e. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)		9,963	9,963	10,422	11,832	13,088	13,965	14,687	14,938	15,040	15,188	15,337	16,547	160,969
	a. Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand		9,963	9,963	10,422	11,832	13,088	13,965	14,687	14,938	15,040	15,188	15,337	16,547	160,969

was 0 in Dec T/U
was 697,115 in Dec 138,556 +7,506
23,505 +1,372

Attachment A

HEARING EXHIBIT - 00000695

PEF-POD2-00001

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4c)
(In Dollars)

Base
20035307

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
	b Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	
	c Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d Other		-	-	-	-	-	-	-	-	-	-	-	-	
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	(3,216)	(3,327)	(3,438)	(3,549)	(3,660)	(3,772)	(3,883)	(3,994)	(4,105)	(4,216)	(4,327)	(4,438)	(4,549)	
4	CWIP - Non-Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Net Investment (Lines 2 + 3 + 4)	29,876	29,765	29,654	29,543	29,432	29,320	29,209	29,098	28,987	28,876	28,765	28,654	28,543	
6	Average Net Investment		29,821	29,709	29,598	29,487	29,376	29,265	29,154	29,043	28,931	28,820	28,709	28,598	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes 11.16%		277	276	275	274	273	272	271	270	269	268	267	266	3,260
	b Debt Component (Line 6 x 2.57% x 1/12) 2.64%		51	51	50	50	50	50	50	49	49	49	49	49	596
8	Investment Expenses														
	a Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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 0.016238		45	45	45	45	45	45	45	45	45	45	45	45	541
	e Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)		484	483	482	481	479	478	477	476	474	473	472	471	5,730
	a Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b Recoverable Costs Allocated to Demand		484	483	482	481	479	478	477	476	474	473	472	471	5,730

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4d)
(In Dollars)

Peaking Retain service date November 2006
20048123

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a Expenditures/Additions		-	-	83,493	172,836	55,368	104,160	27,064	18,527	-	26,884	220,000	-	708,521
	b Clearings to Plant		-	-	-	-	-	-	-	-	-	-	1,814,230	-	
	c Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d Other		-	-	-	-	-	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base	-	-	-	-	-	-	-	-	-	-	-	1,814,230	1,814,230	
3	Less: Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	(2,280)	(6,840)	
4	CWIP - Non-Interest Bearing	905,709	905,709	905,709	989,202	1,162,138	1,217,506	1,321,666	1,348,720	1,367,247	1,367,247	1,394,230	0	0	
5	Net Investment (Lines 2 + 3 + 4)	905,709	905,709	905,709	989,202	1,162,138	1,217,506	1,321,666	1,348,720	1,367,247	1,367,247	1,394,230	1,811,950	1,807,390	
6	Average Net Investment		905,709	905,709	947,455	1,075,670	1,189,822	1,269,586	1,335,193	1,357,983	1,367,247	1,380,738	1,603,090	1,809,670	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes 11.16%		8,423	8,423	8,811	10,004	11,065	11,807	12,417	12,628	12,715	12,841	13,979	14,870	136,985
	b Debt Component (Line 6 x 2.57% x 1/12) 2.64%		1,540	1,540	1,611	1,829	2,023	2,158	2,270	2,308	2,324	2,347	2,555	2,736	25,241
8	Investment Expenses														
	a Depreciation 3.39%		-	-	-	-	-	-	-	-	-	-	2,280	4,560	6,840
	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 0.008159		-	-	-	-	-	-	-	-	-	-	1,096	1,096	2,193
	e Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)		9,963	9,963	10,422	11,832	13,088	13,965	14,687	14,936	15,040	15,188	19,912	23,364	172,362
	a Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b Recoverable Costs Allocated to Demand		9,963	9,963	10,422	11,832	13,088	13,965	14,687	14,936	15,040	15,188	19,912	23,364	172,362

HEARING EXHIBIT - 00000696

Attachment B

PEF-POD2-00002

FPL ...s ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
Above Ground Tank Secondary Containment (Projects 4.1 and 4.2 Recap)

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

Base
20035307

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	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	(4,649)	(4,861)	(4,772)	(4,683)	(4,594)	(5,105)	(5,216)	(5,327)	(5,438)	(5,550)	(5,661)	(5,772)	(5,883)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$28,443	28,431	28,320	28,209	28,098	27,987	27,876	27,765	27,653	27,542	27,431	27,320	27,209	
6	Average Net Investment		28,437	28,376	28,265	28,154	28,042	27,931	27,820	27,709	27,598	27,487	27,376	27,264	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		265	264	263	262	261	260	259	258	257	256	255	254	$3,111
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		48	48	48	48	48	47	47	47	47	47	47	46	569
8	Investment Expenses														
	a. Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,334
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.016338		61	45	45	45	45	45	45	45	45	45	45	45	557
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		486	468	467	466	465	463	462	461	460	459	457	456	5,570
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		486	468	467	466	465	463	462	461	460	459	457	456	5,570

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

Peaking Est. in service date November 2005
20048123

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	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	$1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	
3	Less: Accumulated Depreciation	(8,840)	(11,400)	(15,960)	(20,521)	(25,081)	(29,641)	(34,201)	(38,761)	(43,322)	(47,882)	(52,442)	(57,002)	(61,562)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$1,607,390	1,602,830	1,598,270	1,593,710	1,589,149	1,584,589	1,580,029	1,575,469	1,570,909	1,566,348	1,561,788	1,557,228	1,552,668	
6	Average Net Investment		1,605,110	1,600,550	1,595,990	1,591,429	1,586,869	1,582,309	1,577,749	1,573,189	1,568,628	1,564,068	1,559,508	1,554,948	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		22,434	14,885	14,843	14,800	14,758	14,715	14,673	14,631	14,588	14,546	14,503	14,461	$183,837
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		4,101	2,721	2,713	2,705	2,698	2,690	2,682	2,674	2,667	2,659	2,651	2,643	33,605
8	Investment Expenses														
	a. Depreciation 3.39%		4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	54,722
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.008160		1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	13,172
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		32,192	23,264	23,214	23,164	23,113	23,063	23,013	22,963	22,913	22,863	22,812	22,762	285,336
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		32,192	23,264	23,214	23,164	23,113	23,063	23,013	22,963	22,913	22,863	22,812	22,762	285,336

HEARING EXHIBIT - 00000697

PEF-POD2-00003

Attachment C

FPC ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
Underground Storage Tanks (Project 19 Recap)

For Project: UNDERGROUND STORAGE TANKS - BARTOW (Project 19b)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		($18,530)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($18,530)
	b. Clearings to Plant		75,868	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	
3	Less: Accumulated Depreciation	0	(101)	(303)	(504)	(706)	(908)	(1,109)	(1,311)	(1,513)	(1,714)	(1,916)	(2,118)	(2,319)	
4	CWIP - Non-Interest Bearing	94,398	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$94,398	75,767	75,565	75,364	75,162	74,960	74,759	74,557	74,355	74,154	73,952	73,750	73,549	
6	Average Net Investment		85,082	75,666	75,465	75,263	75,061	74,859	74,658	74,456	74,254	74,053	73,851	73,649	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (11.16%)		791	704	702	700	698	696	694	692	691	689	687	685	$8,429
	b. Debt Component (Line 6 x 2.04% x 1/12; 2.04%)		145	129	128	128	128	127	127	127	126	126	126	125	1,641
8	Investment Expenses														
	a. Depreciation (3.19%)		101	202	202	202	202	202	202	202	202	202	202	202	2,319
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (0.009773)		62	62	62	62	62	62	62	62	62	62	62	62	741
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,099	1,096	1,094	1,091	1,089	1,087	1,085	1,082	1,080	1,078	1,076	1,074	13,030
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,099	1,096	1,094	1,091	1,089	1,087	1,085	1,082	1,080	1,078	1,076	1,074	13,030

PEF-POD2-00004
HEARING EXHIBIT - 00000698

Attachment D

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$82,954	$68,001	$16,922	$0	$0	$0	$0	$0	$0	$0	$0	$0	$167,916
	b. Clearings to Plant			0	0	147,916	0	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		$516,221	516,221	516,221	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	
3	Less: Accumulated Depreciation		(64,828)	(73,131)	(81,735)	(91,571)	(102,840)	(113,709)	(124,778)	(135,847)	(146,916)	(157,985)	(169,054)	(180,123)	(191,192)	
4	CWIP - Non-Interest Bearing		0	52,994	120,995	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$451,393	496,083	555,481	572,565	561,497	550,428	539,359	528,291	517,222	506,153	495,084	484,015	472,946	
6	Average Net Investment			473,888	525,782	564,023	567,032	555,963	544,894	533,825	522,756	511,687	500,618	489,549	478,480	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		4,464 (1) (a)	4,953 (1) (a)	5,292 (1) (a)	5,273 (1) (a)	5,170 (1) (a)	5,068 (1) (a)	4,966 (1) (a)	4,862	4,759	4,656	4,553	4,450	$58,483
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		814 (a)	911 (a)	967 (a)	964 (a)	945 (a)	926 (a)	908 (a)	889	870	851	832	813	10,690
8	Investment Expenses															
	a. Depreciation (C)	20.00%		8,604 (3)	8,604 (3)	9,836 (3)	11,069 (3)	11,069 (3)	11,069 (3)	11,069 (3)	11,069	11,069	11,069	11,069	11,069	126,664
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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)	0.016338		574 (4)	703 (4)	904 (4)	904 (4)	904 (4)	904 (4)	904 (4)	904	904	904	904	904	10,319
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,445	15,209	16,999	18,211	18,089	17,967	17,846	17,723	17,602	17,480	17,358	17,236	206,156
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			14,445	15,209	16,999	18,211	18,089	17,967	17,846	17,723	17,602	17,480	17,358	17,236	206,155
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.93753	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)			13,543	14,259	15,937	17,073	16,959	16,845	16,730	16,616	16,502	16,388	16,274	16,159	193,276
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$13,543	$14,259	$15,937	$17,073	$16,959	$16,845	$16,730	$16,616	$16,502	$16,388	$16,274	$16,159	$193,276

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 8.85%, 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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Notes:
Line 8c Based on 2005 Rate Case Settlement in Dkt. 050078-EI

Σ ①'s = 35,205

Σ ②'s = 6,435

Σ ③'s = 71,320

Σ ④'s = 5,797

HEARING EXHIBIT - 00000699
PEF-POD2-00005
Attachment E

18

PEF's Response to Staff's Third Request for Production of Documents (No. 3)

HEARING EXHIBIT - 00000700

080007-EI

CR No. 726975

CONTRACT

349635

BETWEEN

PROGRESS ENERGY SERVICE COMPANY, LLC

AND

CH2M Hill

DOCUMENT NUMBER-DATE
08654 SEP 15 08

HEARING EXHIBIT - 00000701

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CONTRACT NO. _____

This Contract (hereinafter "Contract"), effective November 12, 2007, by and between PROGRESS ENERGY SERVICE COMPANY, LLC, whose address is 410 South Wilmington Street, Raleigh, NC 27601, (hereinafter referred to as "Owner"), and CH2M Hill, a corporation, whose place of incorporation is Florida, and whose office is located at 9311 San Pedro Avenue, Suite 800, San Antonio, TX, 78216, (hereinafter referred to as "Consultant").

This Contract is based on an understanding between Consultant and Owner that Consultant has represented itself as and is qualified, equipped, and available to provide consulting services associated with an entity-wide comprehensive Greenhouse Gas Inventory.

THEREFORE, in consideration of the work to be done by Consultant, the payments to be made by Owner, and the other promises set forth below, the parties agree as follows:

Consultant shall furnish all services, supplies, tools, equipment, and transportation necessary to provide the following -

A detailed analysis of GHG emissions will be conducted for all of the six major GHGs (CO_2, CH_4, N_2O, PFCs, HFCs, and SF6) and will include direct and indirect emissions from each of the following owned or controlled functional areas of the organization:

- Stationary sources (e.g., boilers, turbines, internal combustion engines)
- Electricity transmission and distribution (e.g., transmission and distribution losses from purchased or wheeled electricity)
- Fugitive sources (e.g., air conditioning, fire suppression equipment, SF6)
- Mobile sources (e.g., road, air, rail)
- Process sources (e.g., sorbent use for flue gas desulfurization systems)
- Facilities (e.g., office buildings)

Sources of Scope 3 emissions (as defined in the WBCSD/WRI GHG Protocol - such as employee commuting and transportation of waste materials) will be identified, but not quantified in this scope of work.

Owner will form a GHG Inventory Core Team to lead the project. The Core Team will: (1) generate and execute a Owner GHG Inventory Plan, (2) direct all project activities and (3) prepare project communications for management reviews.

Development of the GHG inventory will require the following distinct tasks:

Task 1. **Develop GHG Inventory Plan.** The GHG Inventory Plan will define the scope of work, roles and responsibilities, project timeline, resource needs for data collection and deliverables. It will also capture key decisions that will be required early in the project, such as operational boundaries; identification of sources that will be included and excluded in the inventory; years to be included for data collection; and the inventory protocol.

Task 2. **Collect Data.** Identified field resources will develop a comprehensive list of GHG emissions sources and will collect operational data required to support the emissions calculations.

Task 3. **Calculate GHG Emissions.** GHG emissions will be calculated and documented on an Excel spreadsheet for each year selected in the GHG Inventory Plan. Benefits from completed or

ongoing emissions reductions projects will also be calculated. Once the inventory has been generated, potential de minimis sources will be identified and a baseline will be established. For each source, the spreadsheet will indicate the quality of the calculation or estimation methodology used and an explanation of why this approach was chosen.

Task 4. **Establish Ongoing Implementation Strategy.** The GHG Inventory Core Team will develop the ongoing strategy for collecting, calculating and documenting the annual GHG emissions inventory and carbon offsets. The recommended strategy will be documented for internal management review.

The Scope of Work shall herein after be referred to as "Work".

The Work is to be undertaken at different Owner sites and at Consultants place of business.

All Work shall be performed as directed by Owner's Designated Representative.

SECTION 2. SCHEDULE OF WORK

The Work shall start on or about November 15, 2007 and shall be completed no later than May 1, 2008. Time is of the essence. Actual dates of Work performance shall be coordinated by Owner's Designated Representative.

Consultant recognizes that in the electric utility industry it is frequently necessary for outage-related work to be rescheduled. Therefore, in accepting this Work, Consultant recognizes that the Work may be rescheduled within a reasonable time of the specified dates and agrees to comply with any reasonable rescheduling of Work without additional cost to Owner.

Consultant shall, within ten (10) days after signing this Contract, submit a detailed schedule indicating the sequence, method, and other specific details of how the Work will be completed.

SECTION 3. PERFORMANCE

All Work shall be undertaken in a professional manner and to the satisfaction of Owner. In performance of the Work, Consultant shall exercise the degree of skill and care required by the generally accepted level of professional standards. Work not completed to the satisfaction of Owner or which does not meet the above standards shall be immediately corrected or revised by Consultant at no cost to Owner. If it is impractical for Consultant to re-perform the Work, Consultant shall either reimburse Owner for any costs it may incur as a result of the defects or, at Owner's option, an equitable portion of the price for the Work shall be refunded to Owner.

SECTION 4. COMMENCEMENT OF WORK

Consultant shall not commence the Work awarded under the Contract and Owner will not be obligated to pay Consultant for Work commenced prior to Consultant's having properly executed the Contract and returned it to Owner.

Except as necessary to comply with the specific pre-conditions set out below, Consultant shall not commence the Work awarded under this Contract, oral or written, and Owner will not be obligated to pay Consultant for Work commenced prior to Consultant satisfying the insurance requirements and providing Owner with an acceptable Certificate of Insurance as set forth in Section 18. Insurance.

SECTION 5. OWNER'S DESIGNATED REPRESENTATIVE

As used in this Contract, "Owner's Designated Representative" means Kristin Beck, 410 S Wilmington Street, PEB 1505, Raleigh, NC. 27601, who is the liaison between Owner and Consultant during performance of the Work. No agreement with Owner's Designated Representative shall affect or modify any of the terms or obligations contained in this Contract except as provided in Section 7. Changes. A copy of all correspondence concerning the authorized Work shall be sent to Owner's Designated Representative specified in the Contract. Owner reserves the right to change its Designated Representative at any time.

SECTION 6. COMPENSATION

[redacted]

Upon completion of performance by Consultant of the Work described above and acceptance by Owner, Owner will pay to Consultant, as full compensation for the Work performed under this Contract, an amount determined to be [redacted] the tasks of Greenhouse Gas inventory Plan Development and Greenhouse Gas Inventory Development. Invoices shall be submitted to the Designated Representative on a monthly basis in order to receive payment.

B. Invoices and Payments

All payments, including the final payment, are subject to adjustment during, after completion, or after termination of the Work on the basis of any final accounting which may be made by Owner. Owner may withhold from any payment, including the final payment: (1) any amount incorrectly invoiced; (2) any amount in dispute; (3) or an amount sufficient to completely protect Owner from any loss, damage or expense arising out of assertions by other parties of any claim or lien against Owner because of Consultant's performance of this Contract, (4) any amount due under the indemnity provisions of this agreement The undisputed portion of any invoice shall be paid by Owner as hereinafter provided.

Invoices for Work performed under this Contract should be sent to: Kristin Beck, c/o Progress Energy Service Company, LLC, 410 S Wilmington Street, PEB 1505, Raleigh, NC 27601. Each invoice must show the Contract number. Unless the compensation is firm price under this Contract, the following information shall apply:

The invoice shall include a statement or be accompanied by a billing transaction register showing each employee's name, classification, hours worked, and applicable rate of compensation to Consultant. If any special equipment has been used, the invoice must also specify the equipment used, hours of usage and rate of reimbursement for use. On-site labor, off-site labor, material and any equipment costs must appear separately on the invoice.

Consultant assumes exclusive liability for all sales or use taxes applicable to any materials, supplies, equipment or tools which Consultant buys, rents or leases and uses or consumes in conjunction with the performance of the Work.

Copies of supplier invoices shall be submitted with Consultant's invoice for (a) the cost of tools, equipment or other property used by Consultant in performance of the Work; and (b) materials, parts or other property that Consultant installs, incorporates, furnishes or otherwise supplies for Owner's use or consumption that becomes the property of Owner; and a note on these copies of invoices that states "property transferred to Owner."

Consultant is responsible for paying the lowest allowable sales or usage tax rate under applicable law for materials supplied under this Contract. Invoices submitted which include payment of tax at higher than the statutorily allowed rate shall be reduced to reflect only the amount Consultant was legally required to pay. Any excess amount paid by Consultant shall not be reimbursed to Consultant.

Prior to final payment, Consultant shall furnish to Owner a signed notarized tax affidavit certifying that all sales or use tax with respect to this property has been paid. The required affidavit is included in this Contract as an attachment titled "N. C. Sales/Use Tax Affidavit."

Subject to the above conditions, final payment will be made not later than thirty (30) days after all of the following have been completed:

(1) All Work has been completed and accepted, including outstanding punch list items, final cleanup, testing, demobilization, and receipt of all required documentation by Owner.

(2) A correct invoice covering the Work has been presented to Owner.

C. Overtime and Portal-to-Portal Pay

[redacted]

D. Overbillings/Offsets/Credits/Refunds

[redacted]

SECTION 7. CHANGES

Owner's Designated Representative may, at anytime, provide Consultant with a written field directive to make changes in, additions to and omissions from the Work or the schedule, and Consultant shall promptly proceed with the performance of this Contract as so changed. If Consultant becomes aware of a change in the Work or the schedule that it feels is necessary, it shall provide a written request to the Owner Designated Representative, for a change to be issued. Any claim for equitable adjustment of the compensation as a result of the change, addition or omission must be submitted to Owner within ten (10) calendar days from the date the directive is issued. These claims must be itemized and supported with adequate documentation. Work performed outside the scope or schedule set forth in this Contract which is not requested by a written field directive may not form the basis of a claim for additional compensation. If an omission is made from the Work, a decrease in compensation shall be agreed to by both parties. Any

increase or decrease in compensation to be paid under this Contract for changes in Work shall not be binding on Owner unless and until a Contract Amendment setting forth the compensation change is signed by both parties.

SECTION 8. FINANCIAL AUDITS

Consultant shall maintain accurate and detailed records, in accordance with generally accepted accounting principles consistently applied, of all expenditures or costs relating to any Work performed under this Contract and of any performance statistics relevant to this Contract. If the Work is being performed other than on a fixed price basis and/or includes incentive provisions, Owner shall have the right to inspect, examine and make copies of any or all books, accounts, records and other writings of Consultant relating to the performance or cost of the Work. If the Work is being performed on a fixed-price basis only, Owner shall have the above-specified rights only upon termination or suspension of the Work. Such audit rights shall be extended to Owner or to any representative designated by Owner. Audits shall take place at times and locations mutually agreed upon by both parties, although Consultant must make the materials to be audited available within one (1) week of the request for them. Costs incurred in undertaking the audit will be borne by Owner but costs incurred by Consultant as a result of Owner's exercising its right to audit will be borne by Consultant.

SECTION 9. INTELLECTUAL PROPERTY

Consultant agrees that it will promptly notify Owner of any discovery or invention that relates to or arises out of the Work paid for under this Contract. Consultant further agrees to assign all rights Consultant has or may assert to such invention or discovery, including patent, copyright, and trade secret rights. Where such rights are assigned to Owner, the application for patent or copyright shall be made at the discretion and expense of Owner and through attorneys named by Owner.

Any copyrightable material in any form shall be deemed to be a "work for hire" under the Copyright Act. Consultant hereby assigns any copyright in any copyrightable material produced hereunder to Owner, and agrees to execute assignment documents that may be deemed necessary or appropriate by Owner to protect its ownership of any such copyright.

SECTION 10. PUBLICATION OF RESEARCH

Consultant agrees not to publish, release, disclose, or disseminate to anyone other than Owner designated employees with a need to know, whether in writing or orally, the results of any Work performed or any information obtained as a result of Work, without express prior written consent by Owner.

SECTION 11. NOT USED

SECTION 12. TERMINATION AND SUSPENSION

Each party has the absolute right to cancel this Contract at any time for its convenience, but both agree to give five (5) days notice (commencing after receipt of a written notice) to the other party of its election to terminate. In the event of termination Consultant shall use its best efforts to immediately curtail all charges and commitments made under this Contract. If Owner requests the termination, it will pay Consultant for the work actually performed and all Work related expenses he/she has incurred or become obligated for prior to the date of termination. In the event this Contract is based upon a firm fixed price, Consultant understands that Owner will not pay Consultant more than the fixed price agreed upon. If Consultant terminates, he/she shall be responsible for all costs and expenses incurred by Owner in hiring another Consultant to complete the Work beyond those agreed to in the above compensation section.

Consultant shall also cooperate with Owner and the new Consultant in explaining the Work which was done prior to Consultant's withdrawal and assisting the new Consultant in getting fully acquainted with the Work as quickly as possible.

SECTION 13. PATENTS AND COPYRIGHTS

Consultant agrees that in performing this Contract it will not use or provide to Owner any process, program, document, data, design, device or material which infringes on any patent, copyright, trade secrets, or other proprietary right of any third party. Consultant agrees to indemnify and defend Owner, at Consultant's expense, against any suit or proceeding brought against Owner for any infringement arising out of Consultant's Work under this Contract. Owner will promptly notify Consultant in writing of any such suit or proceeding and will assist Consultant in defending the action by providing any necessary information at Consultant's expense. If use of the Work is enjoined, then Consultant shall obtain a license for Owner to continue using the Work, or modify the Work so that it no longer infringes, without degrading its function or performance.

SECTION 14. STATUS OF CONSULTANT

It is the intent of the parties to create between them the relationship of owner and independent Consultant. It is agreed that nothing shall operate to change or alter such relationship, except a further agreement in writing between them.

SECTION 15. SUBLETTING OR ASSIGNING CONTRACT

Consultant shall not sublet any portion of any Work or assign the Contract without first submitting the proposed subcontract or assignment to Owner's Designated Representative and receiving written consent from Owner's Designated Representative to subcontract or assign. Any assignment without the consent of Owner shall be void. A request to sublet or assign must contain the name and location of individuals or firms to whom Work will be sublet or to whom the Contract is to be assigned, information on the qualifications and experience of those individuals or firms to perform the Work, and an estimate of the cost of the Work to be performed by the subcontractor or assignee. The general terms and conditions of this Contract and any Contract Amendment regarding the Work to be performed must be incorporated into and attached to any subcontract or assignment. Consent to subletting or assignment will not relieve Consultant of responsibility for the performance of Work in accordance with the terms and conditions of this Contract and any Amendments executed by both parties.

SECTION 16. REPORTS

Consultant shall furnish to Owner a work progress report in letter form at the end of each month of the Contract term in which authorized Work is being undertaken. The report will include a description of the Work undertaken, in progress, and completed during the period covered and statements indicating whether the schedule of various tasks is being met.

SECTION 17. CONSULTANT PERSONNEL MATTERS

Personnel provided by Consultant under this Contract shall at all times remain the sole responsibility of said Consultant for purposes of personal and professional liability.

Consultant is solely responsible for all aspects of the labor relations of its personnel, including but not limited to, wages, benefits, discipline, hiring, firing, promotions, pay raises, overtime and job and shift

assignments. Owner shall have no responsibility for or power over these areas. Such personnel shall be and remain the employees of Consultant at all times.

All personnel to be provided by Consultant under this Contract shall be employees of Consultant and shall not be independent contractors. Consultant shall withhold from each employee's pay sufficient funds for federal, state, and local income taxes as required by applicable law, funds required by the Federal Insurance Contributions Act, and as may otherwise be required by applicable law. Consultant further agrees to defend, indemnify, and hold Owner harmless from any claims, fines, and penalties based on any allegations that such withholdings were not made, or that such withholdings were inadequate.

Consultant shall comply with the Fair Labor Standards Act, and shall pay overtime to its employees as required by all applicable federal, state and local laws, rules, regulations, and ordinances. In the event that Consultant fails to comply with this requirement, Consultant shall be required to indemnify, defend and hold Owner harmless from all claims, actions, fines, penalties, and liabilities resulting from any such failure.

In selecting employees to undertake any Work authorized under this Contract, Consultant shall select only those persons who are qualified by the necessary education, training and experience to provide a high quality performance of the Work. If Owner determines, in its sole discretion, that any personnel supplied by Consultant are unsuitable for the Work, Owner shall so advise Consultant and Consultant shall remove that employee from performing Work under this Contract and assign other individuals to perform the Work. If Owner determines, in its sole discretion, that the presence on Owner's premises of any employee of Consultant is not consistent with the best interest of Owner, Owner may direct Consultant to remove that employee from the premises and assign another employee to work in place of the unacceptable employee. Replacement of employees under either of the above circumstances shall be at no cost to Owner. Consultant shall absorb any travel costs or travel time to the site for the replacement employee and from the site for the replaced employee. Consultant shall give Owner advance notice prior to removing Consultant's supervisory or professional personnel from the job.

Consultant's employees shall be properly dressed to Owner's standards at all times while on Owner's property. Employees not properly dressed will be refused entry to or will be subject to discharge from the Work Site.

Code of Ethics

Consultant, Consultant's employees, and employees of Consultant's subcontractor(s) performing Work under this Contract shall comply with Owner's Code of Ethics. Owner will make the Code of Ethics available to Consultant in order for Consultant to provide a copy to any employee with (i) a presence for a single period of 15 working days or more upon property owned or leased by Owner or any of Owner's subsidiaries or affiliates and/or (ii) access to Owner's business critical infrastructure. Each such employee shall sign an Acknowledgment Form in substantially the form set forth by Owner. Consultant shall retain the signed forms for Owner audit purposes for the term of the Contract plus one (1) year. The audit right provided herein shall not be restricted by any other audit provisions of the Contract. Consultant shall not be required to obtain signatures on Acknowledgement Forms for those employees assigned to Owner sites exclusively to provide storm support.

Consultant, Consultant's employees, and employees of Consultant's subcontractor(s) performing Work under this Contract are obligated to comply with all applicable laws and regulations and with all applicable health, safety and security rules, programs and procedures. The Owner Code of Ethics identifies principles concerning lawful and ethical conduct that must be followed by Consultant's employees in the performance of Work. The Code of Ethics also provides for an AlertLine reporting

mechanism that enables the reporting of suspected violations of law and of the Code of Ethics as a part of Owner's program to prevent and detect violations of law and criminal or unethical conduct.

SECTION 18. INSURANCE

Consultant shall provide and maintain in full force and effect at no additional cost to Owner for the duration of the Contract the following minimum amounts of insurance:

(a) Commercial general liability insurance or comprehensive general liability insurance with a minimum limit of $2,000,000 per occurrence for bodily injury and damage to property including contractual liability, premises/operations, products/completed operations, independent contractors, broad form property damage, and personal injury and a minimum aggregate amount of $4,000,000 or commercial/comprehensive general liability insurance plus additional excess umbrella liability insurance to meet these limits.

(b) Comprehensive automobile liability insurance with a minimum combined single limit of $1,000,000 per accident for bodily injury and damage to property, or covering bodily injuries or death in a sum not less than $500,000 per person and $1,000,000 per accident and covering damages to property in a sum of at least $250,000 per accident or comprehensive automobile liability insurance plus additional excess umbrella liability insurance to meet these limits. This insurance shall apply to any auto, whether owned or non-owned.

(c) Workers' compensation insurance as specified by state law in each state where work is to be performed; when workers' compensation is required, Consultant shall also provide employer's liability insurance in the minimum amount of $500,000 each accident and $500,000 per employee for bodily injury by disease with a disease policy aggregate of $1,000,000, or employer's liability insurance plus additional excess umbrella liability insurance to meet these limits.

All such coverages shall be primary. Consultant agrees that it shall add Owner, its officers, employees, agents and shareholders [and the North Carolina Eastern Municipal Power Agency (NCEMPA) for work performed at or associated with Roxboro Unit No. 4, Mayo Plant, Brunswick Nuclear Plant, and Harris Nuclear Plant] and all of Owner's parent, subsidiary, and affiliate companies to Consultant's liability insurance policies as additional insureds. Consultant shall require its insurance carrier or agent to certify that this requirement has been satisfied on all Insurance Certificates issued under this Contract.

Consultant waives and shall require its insurers providing the coverages specified above (excluding professional liability coverage, if required) to waive all rights of recovery against Owner, its officers, employees, agents, and shareholders [and the North Carolina Eastern Municipal Power Agency (NCEMPA) for work performed at Roxboro Unit No. 4, Mayo Plant, Brunswick Nuclear Plant, and Harris Nuclear Plant] and all of Owner's parent, subsidiary, and affiliate companies. Consultant shall require its insurance carrier or agent to certify that this requirement has been satisfied on all Insurance Certificates issued under this Contract.

Before any Work is initiated and before any invoices are paid for Work performed under this Contract, Consultant shall provide written proof of compliance with the above insurance requirements by delivering to:

Kyeshia Woods-Cosby
Progress Energy Service Company
P. O. Box 1551 (PEB 2C3)
Raleigh, NC 27602

a copy of certificate of insurance completed by his insurance carrier or agent certifying that minimum insurance coverages as required above are in effect and that the coverage will not be canceled or changed until thirty (30) days after written notice is given Owner. Consultant shall maintain, update, and renew the Certificate for the duration of the Contract. No payment will be made to Consultant prior to receipt by Owner of an acceptable Certificate of Insurance. In the event an acceptable Certificate of Insurance becomes outdated, Owner may elect to withhold payment of invoices, suspend Work or take other appropriate action until an acceptable and properly dated Certificate is received by Owner.

SECTION 19. INDEMNITY

To the maximum extent permitted by applicable law, Consultant shall indemnify and defend Owner (including its parent, subsidiary and affiliate companies), its officers, employees, agents, and any other party with an ownership interest in the premises, from and against all liability, loss, costs, claims, damages, expenses, judgments, and awards, whether or not covered by insurance, arising or claimed to have arisen:

(a) wholly or in part from acts or omissions of, or as a result of Work done or omitted from being done, or as a result of negligence by Consultant, subcontractors or assignees and their agents or employees, or Owner's negligence (including its parent, subsidiary and affiliate companies) which resulted in:

(1) injury to (including mental or emotional) or death of any person, including employees of Owner (including its parent, subsidiary and affiliate companies), or

(2) damage to or destruction of any property, real or personal, including without limitation property of Owner (including its parent, subsidiary and affiliate companies) and its other contractors, Owner's (including its parent, subsidiary and affiliate companies') employees, and fellow employees;

(b) out of injuries sustained and/or occupational diseases contracted by Consultant's, subcontractor's, or assignee's employees, if any, of such a nature and arising under such circumstances as to create liability by Owner (or its parent, subsidiary or affiliate companies) or Consultant under the Workers' Compensation Act, and all amendments thereto, of the state having jurisdiction, including all claims and causes of action of any character against Owner (and its parent, subsidiary and affiliate companies) by any employee of Consultant, its subcontractors or assignees, or the employer of such employees, or any person or concern claiming by, under or through them resulting from or in any manner growing out of such injuries or occupational diseases; and

(c) from demands, actions or disputes asserted by any subcontractors, employees or suppliers of Consultant.

Indemnification shall include all costs including attorney's fees reasonably incurred in pursuing indemnity claims under or enforcement of this Contract.

SECTION 20. SECURITY

Consultant and Consultant's employees who perform Work at any Owner property, shall comply with the security practices and procedures prescribed by Owner to cover that Property. Consultant shall advise its employees of these practices and procedures and secure their consent in a form satisfactory to Owner to abide by the procedures. Owner will make a copy of these practices and procedures available to Consultant upon request.

SECTION 21. FITNESS-FOR-DUTY POLICY

1. Consultant acknowledges its awareness of Owner's contract personnel Fitness-For-Duty Program (FFDP) Drug and Alcohol Abuse Policy, which is as follows:

> The use, possession, or sale of narcotics, hallucinogens, depressants, stimulants, marijuana, or other controlled substances on Owner Property or while in pursuit of Owner business is prohibited. (This does not apply to medication prescribed by a licensed physician and taken in accordance with such prescription.) Unauthorized consumption of alcohol on Owner Property is also prohibited. The use of the above substances or alcohol on or away from Owner Property which adversely affects the employee's job performance, or may reflect unfavorably on public or governmental confidence in the manner in which Owner carries out its responsibilities, as determined by Owner, is also prohibited.

The term "Owner Property" includes any property or facility owned, leased, or under control of Progress Energy, Inc. or any of it subsidiaries wherever located, including land, buildings, structures, installations, boats, planes, helicopters, and other vehicles.

SECTION 22. LAWS AND PROJECT RULES

A. General

Consultant and its subcontractors, if any, shall observe and abide by all applicable laws, federal, state and local, and the rules and regulations of any lawful regulatory body acting thereunder in connection with the Work. Without limiting the foregoing, Consultant agrees to comply with applicable provisions of the Americans with Disabilities Act, Fair Labor Standards Act of 1938, Executive Order No. 11246, the Rehabilitation Act of 1973, the Vietnam Veterans Readjustment Act of 1974, as amended, and their respective implementing regulations, which are made a part hereof as if set out herein. Consultant warrants that it will meet the legal requirements of the Immigration Reform and Control Act of 1986, including, but not limited to, verifying workers' eligibility for U.S. employment through the completion of an I-9 form. Consultant and its subcontractors, if any, shall also comply with all applicable Owner health, safety and security rules, programs or procedures.

To the extent applicable, during the performance of this Contract, the Consultant agrees as follows:

(1) The Consultant will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. Consultant will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to the following: Employment, upgrading, demotion, or transfer, recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including

apprenticeship. Consultant agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the contracting officer setting forth the provisions of this nondiscrimination clause.

(2) Consultant will, in all solicitations or advertisements for employees placed by or on behalf of Consultant, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(3) Consultant will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice to be provided by the agency contracting officer, advising the labor union or workers' representative of Consultant's commitments under section 202 of Executive Order 11246 of September 24, 1965, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(4) Consultant will comply with all provisions of Executive Order 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(5) Consultant will furnish all information and reports required by Executive Order 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the contracting agency and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations, and orders.

(6) In the event of Consultant's non-compliance with the nondiscrimination clauses of this Contract or with any of such rules, regulations, or orders, this Contract may be canceled, terminated or suspended in whole or in part and Consultant may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(7) Consultant will include the provisions of paragraphs (1) through (7) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to section 204 of Executive Order 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. Consultant will take such action with respect to any subcontract or purchase order as may be directed by the Secretary of Labor as a means of enforcing such provisions including sanctions for noncompliance: Provided, however, that in the event Consultant becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction, Consultant may request the United States to enter into such litigation to protect the interests of the United States.

Consultant shall indemnify and hold Owner (or its parent, subsidiary or affiliate companies) and its plant co-owners harmless with respect to any claims, expenses (including attorney's fees), liability or damages arising out of Consultant's failure to comply with any applicable laws, rules, or regulations, or any Owner rules, programs, or procedures.

Work performed and materials and equipment provided by Consultant shall conform to and comply with all the applicable federal, state, and municipal laws, rules, and regulations concerning occupational health and safety, including, but not limited to, the Occupational Safety and Health act of 1970 and the regulations and standards issued thereunder (hereinafter "OSHA requirements"). Consultant warrants that any work performed in a location partially or entirely under Consultant's control shall be performed in accordance with "OSHA Requirements". Consultant further warrants that all materials and equipment furnished by Consultant shall conform to and comply with all applicable provisions of "OSHA requirements" and the regulations and standards issued thereunder, specifically those (designed to accept a lockout device, machine guards in place, etc.). Consultant shall require these warranties of adherence to "OSHA requirements" from each subcontractor and supplier it employs. Consultant shall indemnify and

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hold harmless Owner (including its parent, subsidiary and affiliate companies) from all damages suffered by Owner (including its parent, subsidiary and affiliate companies) (including damages to third parties) as a result if the failure of Consultant or any of its subcontractors or suppliers to comply with "OSHA requirements" and for the failure of any of the materials or equipment.

Consultant shall fully comply with all export and import control laws and regulations with regard to any Work performed by Consultant or with regard to information supplied by Owner to Consultant under this Agreement. In particular, Consultant shall not directly or indirectly use, export, re-export, distribute, transfer or transmit any such Work or information in whole or in part, in any form without all required United States and foreign government licenses and authorizations, including but not limited to any applicable export controls of the U.S. Nuclear Regulatory Commission, the U.S. Department of Energy or the U.S. Department of Commerce. In no event shall Owner be obligated under this Contract or any other agreement to provide access to or furnish any Work or information except in compliance with applicable United States export control laws, regulations, policies, licenses and approvals.

Notices

All notices or official communications required to be given hereunder shall be in writing by either party and shall be deemed sufficient when mailed by United States certified mail, return receipt requested, or hand delivered to Owner's Designated Representative (if to Owner) at the addresses set forth herein or by recognized overnight delivery service, to the address initially set forth in the Contract. All notices shall be deemed delivered on the day they are hand-delivered to the other party or, if sent by overnight delivery service, two (2) days after tendered to such service.

Either party may change its address for the receipt of notices, requests or other communications hereunder by written notice duly given to the other party. This change shall be made by Amendment.

The parties' obligation to provide written notice to each other may not be waived. Electronic or computerized mail is not an acceptable form of delivery of notices required by this Contract. The Parties expressly and unequivocally waive any claim against the other Party based upon actual, verbal, or constructive notices. All written notice requirements are to be strictly construed and are a nonwaivable condition precedent to pursuing any claims, rights, or remedies by Consultant under this Contract.

B. Employment Taxes and Contributions

Consultant assumes exclusive liability for all contributions, taxes or payments required to be made under the applicable federal and state Unemployment Compensation Act, Social Security Acts and all amendments, and by all other current or future acts, federal or state, requiring payment by the Consultant on account of the person hired, employed or paid by Consultant for Work performed under this Contract. When Work is to be performed in South Carolina, Consultant shall submit to Owner, prior to commencement of Work, a properly completed State of South Carolina, Department of Revenue, Nonresident Taxpayer Registration Affidavit Income Tax Withholding form which will be included as an attachment.

C. Drawings and Specifications

It is the intent of Owner to have all drawings and specifications for the Work comply with all applicable statutes, regulations, and ordinances. If Consultant discovers any discrepancy or conflict between the drawings and specifications and applicable legal requirements, Consultant shall immediately report the discrepancy in writing to Owner's Designated Representative.

D. Federal Subcontracting Requirements:

This section is applicable only to a contract which is in excess of $500,000 ($1,000,000 for constructions of any public facility). The federal subcontracting requirements do not apply to contracts with small disadvantaged business concerns, women-owned business concerns, hubzone small business concerns, veteran-owned small business concerns, and small business concerns. The language applies to contracts with larges business concerns only.

1. The provisions of the following Laws, Executive Orders, and any rules and regulations issued thereunder, are incorporated herein by reference as part of this Contract.

   - Provisions of the Utilization of Small Business Concerns clause set forth at Section 52.219-8 of the Federal Acquisition Regulations, Title 48 of the Code of Federal Regulations
   - Provisions of the Small Business Subcontracting Plan clause set forth at Section 52.219-9 of the Federal Acquisition Regulations, Title 48 of the Code of Federal Regulations.

2. The Consultant agrees to fully comply with such provisions and any amendments thereof. In addition, all subcontracts and agreements that the Consultant enters into to accomplish the Work under the terms of this Contract shall obligate such subcontractors to comply with such provisions.

3. Compliance with the above provisions involve the development of a subcontracting plan, as prescribed in 19.704 of the Federal Acquisition Regulations, herein incorporated by reference. The attached Supplier Diversity and Business Development Subcontracting Report shall be used to report awards to small business concerns under the subcontracting plan.

SECTION 23. SEVERABILITY

If any term or provision of this Contract is held illegal or unenforceable by a court with jurisdiction over the Contract, all other terms in this Contract will remain in full force, and the illegal or unenforceable provision shall be deemed struck. In the event that the stricken provision materially affects the rights, obligations or duties of either party, Owner and Consultant shall substitute a provision by mutual agreement that preserves the original intent of the parties as closely as possible under applicable law.

SECTION 24. AMENDMENT OF CONTRACT

The terms and conditions of this Contract may be changed or modified only by execution of a written Contract Amendment executed by both parties. Oral amendments to this Contract or to any Amendment issued under it shall have no effect.

SECTION 25. GOVERNING LAW

This Contract shall be governed by the laws of the State of North Carolina, except that the North Carolina conflict-of-law provisions shall not be invoked in order to apply the laws of any other state or jurisdiction. Owner and Consultant expressly waive their rights to a trial by jury in any action brought hereunder.

SECTION 26. CONFIDENTIALITY; USE OF INFORMATION

The terms of this Contract and all Amendments to it are to remain confidential and shall not be provided in any form to any other party except upon order of a regulatory body or a court of competent jurisdiction. Consultant will not make any public statements or publish any information related to the Work performed or to be performed under this Contract without the prior written consent of Owner.

Materials which are reviewed by Consultant in the course of this Contract may contain trade secrets which are the property of Owner or which have been loaned, licensed, purchased or leased for Owner's use. Consultant agrees not to reveal any trade secret material to any person in any form and further agrees not to use the material for itself for any purpose not connected with this Contract.

Consultant agrees that if access is granted to Owner's computer network or a segment thereof, that this access is solely for the business purpose(s) described in Section 1 of this Contract. Consultant agrees that access for any other purpose or the use of Owner's computer network to access other networks, is strictly forbidden and that Consultant is responsible and liable for all damages or unauthorized access resulting from these actions. This activity will result in the discontinuation of any and all network connections, and Consultant understands that it may be subject to civil and/or criminal prosecution. Consultant further agrees that any information that it obtains from Owner's computer network is subject to all of the terms and conditions of this Contract.

Any program, document, data or information supplied by Consultant to Owner may be used, copied or disclosed by Owner as necessary in the normal course of its business, notwithstanding any copyright of Consultant in such materials and notwithstanding any notices or legends appearing thereon.

All reports, correspondence, documents, data, and other information relating to the Work are exclusively Owner's property and are to be considered as proprietary and confidential. All copies of all materials which are provided to Consultant by Owner must be returned to Owner upon completion of each assignment and before final payment for the completed Work will be made.

Consultant shall obtain a statement from every employee who will work under this Contract that he/she understands and agrees with the terms of the Contract.

SECTION 27. PUBLIC COMMUNICATION

Consultant agrees to cooperate with Owner in maintaining good community relations. Owner will issue all public statements, press releases, and similar publicity concerning the Work, its progress, completion, and characteristics. Consultant shall not make or assist anyone to make any such statements, releases, photographs, or publicity without prior written approval of Owner.

SECTION 28. NONWAIVER

Owner's failure to insist on performance of any of the terms and conditions herein or to exercise any right or privilege or Owner's waiver of any breach hereunder shall not thereafter waive any of Owner's rights or privileges under this Contract or at law. Any waiver of any specific breach shall be effective only if given expressly by Owner in writing.

SECTION 29. MERGER

This Contract embodies the entire agreement between Owner and Consultant. The parties shall not

PEF-POD3-NO3-017 HEARING EXHIBIT - 00000717

be bound by or liable for any statement, writing, representation, promise, inducement or understanding not set forth above. No changes, modifications or amendments of any terms and conditions of this Contract are valid or binding unless agreed to by the parties in writing and signed by their authorized agents.

Each party to this agreement and its counsel have participated in the creation of this agreement. The normal rule of construction to the effect that ambiguities are to be resolved against the drafting party shall not be employed in the interpretation of this agreement or of any amendments or exhibits to this agreement.

SECTION 30. BACKGROUND INVESTIGATION AND DRUG SCREEN

Consultant shall conduct background investigations (BI) as described below for all Consultant's or sub-contractor's employees where the scope of work to be performed will require: (i) a presence for a single period of 15 working days or more upon property owned or leased by Owner or any of Owner's subsidiaries or affiliates and/or (ii) access to Owner's business critical infrastructure. In addition, BI requirements may be applied to other personnel at the sole discretion of Owner's Designated Representative. Owner shall reimburse Consultant a reasonable and customary amount for performing such full or updated background investigations unless Work is performed on a firm fixed price basis. Owner shall not be obligated to reimburse Consultant for any BI expense for individuals who fail to meet the minimum acceptable qualifications. Owner has the right to require proof of such investigation and satisfactory compliance with the minimum criteria, which shall be readily available for Owner's inspection. Owner requires that Consultant maintain records of investigations for a minimum of five (5) years after the Work is completed.

Consultant is solely responsible for ensuring that its employees assigned to the Work meet or exceed the requirements of this section. Consultant must have all background investigations completed prior to the start of Work or in the case of emergencies, may be permitted to start Work while the investigations are being conducted. (If an emergent need requires delay in processing, all background investigations must be completed within 10 working days of the start date)

A. Responsibilities

Consultant shall be responsible to:

1. Initiate and ensure the completion of the appropriate background investigation. Employees should be required to complete a background questionnaire or employment application which includes history of residences, employment/unemployment periods, military history and criminal history. Consultant is the employer and makes decisions regarding assignments based on these guidelines.

2. Notify the worker of the terms and conditions of the background investigation and requirements of this Contract.

3. Furnish Owner with workers who meet or exceed the requirements of the BI and terms and conditions of the Contract.

4. Obtain written permission for the release of the worker's personal history information and information contained in the background investigation report and drug screen to Owner.

5. Require worker or subcontractor to report any arrest and evaluate under the rejection criteria to determine if worker meets Owner's criteria for rejection. (All workers who meet the criteria for rejection must be removed from Owner's Work immediately.)

PEF-POD3-NO3-018

HEARING EXHIBIT - 00000718

B. Types and Components of Background Investigation

1. Full Background Investigation

a. Employment History

Except as noted below, employment history must be verified for a minimum of 3 years, or to age 18, with previous employers by obtaining the following information:

Verification of all claimed periods of employment including disciplinary history, reason for termination and eligibility for rehire, and any other information that would reflect adversely upon reliability and trustworthiness.

If the employment history cannot be verified for the entire 3-year period, the reason must be included in the background investigation report.

Verify periods of self-employment and/or unemployment exceeding one hundred eighty (180) days within the 3 year period. Where information is not available, it will be verified by a reference or other sources. If no other source is available a relative may verify unemployment periods.

b. Military Record

All full time military service within the 3-year period must be verified by using Form DD-214 (member 4 copy) or other means.

c. Criminal Record

Prior to the applicant beginning employment a criminal history record check covering the previous five years, or to age 18, shall be conducted in each state/locality where the applicant has resided and in areas where the applicant has worked or attended school for more than 90 days during past 5 years.

Record checks should be conducted by contacting the appropriate agency of record such as state law enforcement agency, state criminal record repositories, local law enforcement agencies, state and local courts. Consultant shall ensure record repositories hold complete criminal history information (pending cases, misdemeanor records, and felony records, etc).

Reported criminal records should include specific offense information, court and jurisdiction and disposition of charge.

2. Updated Background Investigation

An updated background investigation is acceptable for re-hired workers if the worker previously had a full background investigation completed that meets Owner's criteria and it was completed by the current Consultant within the past three years of current effective work start date. The following components shall be checked:

- Employment history which covers the period of separation from Consultant exceeding 90 days
- Criminal history check in the county or counties where worker has resided and in areas where the applicant has worked or attended school for more than 90 days since the last BI for Progress Energy was conducted

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- Drug screen

C. Rejection Criteria to Disqualify Candidates for Assignment

The decision by Consultant to disqualify a candidate for assignment shall be based upon consideration of all relevant information, favorable and unfavorable, as to whether the assignment would be clearly consistent with the necessity to maintain an environment conducive to a safe work place.

To assist in making appropriate determinations, this matrix identifies several types of adverse information. These are not all-inclusive, but contain many of the factors, which may raise legitimate questions to a person's eligibility for assignment.

1. Criminal Charges

a. Criminal Charges Pending

"Pending" is defined as awaiting formal review by the court to determine the disposition of the arrest. All pending charges will be evaluated on a case by case basis; however pending charges which may meet Progress Energy's criteria for disqualification if convicted will normally preclude an acceptable recommendation.

Charges which result in a disposition of adjudication withheld, nolle pross, pre-trial intervention, prayer for judgment continued or are otherwise unadjudicated shall be evaluated on a case by case basis. This evaluation shall focus on the status of the charge, and the behavior or incident which resulted in the charge being made, and the effect on an applicant's trustworthiness and reliability.

b. Felony Convictions

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
Any felony conviction with in the last five years	Not eligible for assignment for five years from the date of conviction.
Persons on active probation/parole or a work furlough program for a felony conviction or participating in court diversion program for charges which would meet rejection criteria. (Ex. Pre-trial intervention and deferred prosecution).	Not eligible for assignment until completion of probation or parole or court diversion program. Eligibility must also comply with criteria above. (As if convicted)
Failure to fulfill a court order (i.e. failure to appear) for any felony conviction.	Not eligible for assignment until disposition of court order is completed.

c. Misdemeanor Convictions

Multiple misdemeanor convictions demonstrate a pattern of continued disregard for the laws of the land. Such disregard without adequate evidence of rehabilitation raises doubt as to the person's reliability and trustworthiness.

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
Any misdemeanor conviction within the last five years involving illegal drugs (includes individuals currently serving a court-ordered diversion program)	Not eligible for assignment for five years from date of last conviction.
Any misdemeanor conviction within the last year involving violence or theft.	Not eligible for assignment for one year from the date of conviction.
Two or more misdemeanor convictions (excluding infractions [i.e. speeding and non-moving violations]) within the last five years. For example, convictions in 11/2005, and 11/2006 not eligible until 11/2010	Not eligible for assignment for five years from the date of earliest conviction.
Persons on active probation/parole or a work furlough program for a misdemeanor conviction or participating in court diversion program for charges which would meet rejection criteria. (Ex. Pre-trial intervention and deferred prosecution).	Not eligible for assignment until completion of probation or parole or court diversion program. Eligibility must also comply with criteria above. (As if convicted)
Failure to fulfill a court order (i.e. failure to appear) for any misdemeanor conviction	Assignment may not be recommended based on the severity of the court order.

2. Other

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
One drug test failure	Not eligible for assignment for 5 years.
Evidence or admission of use, possession or sale of illegal substances	Not eligible for assignment for 5 years from the most recent occurrence.
The refusal to participate in drug testing	Not eligible for assignment.
Attempted to subvert the testing process, or has shown in anyway to have altered a specimen provided for testing	Not eligible for assignment for 5 years.
Theft of company property from past employer	Not eligible for assignment for 3 years from the most recent occurrence.
Any other information that would adversely reflect upon the reliability and trustworthiness of the person as it relates to their assignment to Progress Energy	Not eligible for assignment – eligible to reapply determined on a case by case basis.

D. Drug Screen

All candidates who will require a BI will also be required to have a Pre-assignment Drug Screen. Consultant must have all drug screens completed prior to the start of Work or in the case of emergencies, may be permitted to start Work while the screens are being conducted. (All drug screens must be completed within 10 working days of starting work.)

A certified Health and Human Services Laboratory must perform all drug testing. Only workers whose test result is determined to be negative are eligible to work on Owner controlled property. In addition, individuals that refuse to participate in drug testing, attempt to subvert the testing process, or are shown in any way to have altered a specimen provided for drug testing are not eligible to work under this Contract.

Owner will reimburse Consultant a reasonable and customary amount for performing pre-assignment drug screens unless Work is performed on a firm fixed price basis. Owner shall not be obligated to reimburse Consultant for any Drug Screen expense for individuals who fail to meet the minimum acceptable qualifications.

The drug screening for the substances below and the testing levels generally follow the Department of Transportation Guidelines. Laboratories that use lower cut off levels for drugs or Metabolite than those listed below are acceptable by Owner.

1. Drug Testing Cut Off Concentrations for Screening and Confirmation Levels

Type of Drug or Metabolite	Initial Test	Confirmation Test
Marijuana Metabolites	50	15
Cocaine Metabolites (Benzoylecgonine)	300	150
Phencyclidine (PCP)	25	25
Amphetamines	1000	
Amphetamine		500
Methamphetamine		500 (specimen must also contain amphetamine at a concentration of greater than or equal to 200 ng/ml.)
Opiate metabolites	2000	
Codeine		2000
Morphine		2000
6-monacetylmorphine (6-MAM)		10 (Test for 6-MAM in the specimen. Conduct this test only when specimen contains morphine at a concentration greater than or equal to 2000 ng/ml.)

2. Specimen Collection

The specimen must be collected by trained and qualified collectors and collected under conditions that protect the integrity of the specimen. Laboratory patient service centers and Doctor's Urgent Care are suggested for collection purposes.

SECTION 31. WORKPLACE VIOLENCE PREVENTION

Owner strives to provide a workplace for a worker that is free from physical attack, threats of violence and menacing or harassing behaviors.

Owner will not tolerate any unwanted or hostile physical contact, including physical attack, threat of violence, harassment, or damage of property by or against any worker including Owner employees.

Any worker who experiences, witnesses, or has knowledge of acts, conduct, behavior, or communication (threat) that may constitute or may lead to a workplace violence event should immediately report the incident to any of the following:

- Consultant Supervisor or Owner supervisor or manager, AND
- Corporate Security 1-888-275-4357 or

- The Ethics Line at 1-866-8Ethics (1-866-838-4427)

SECTION 32. LIMITATION OF LIABILITY

Consultant's liability of Owner's damages will in the aggregate, not exceed $2,000,000. This provision takes precedence over any conflicting provision of this Contract. This limitation of liability will apply whether Consultant's liability arises under breach of contract or warranty; tort, including negligence; strict liability; or any other causes of action, and shall include Consultant's officers, affiliated corporations, employees and subcontractors.

In no event shall CH2M HILL, its affiliated corporations, officers, employees, or any of its subcontractors be liable for any punitive, economic or consequential damages, including but not limited to loss of revenue or profits, suffered or incurred by the Client or any of its agents, including other contractors engaged at the project site, as a result of this Agreement or CH2M HILL's performance or non-performance of services pursuant to this Agreement. Limitations of liability provided in this paragraph apply whether the liability is claimed to arise in contract, tort (including negligence), strict liability, or otherwise. This limitation of liability does not apply to Sections 13, 19 or 22 of this contract.

The parties execute this Contract by their signature or the signature of their authorized agents.

CH2M Hill	PROGRESS ENERGY SERVICE COMPANY, LLC,
BY: Joan A. Gilmer	BY: Leanne Borgen
NAME (printed): Joan A. Gilmer	NAME: Leanne Borgen
TITLE: Vice President	TITLE: Sourcing Specialist
DATE: November 19, 2007	DATE: 11/13/07

Should the person's title who is executing this document not indicate that he/she is a corporate officer, an affidavit signed by a corporate officer shall be provided stating that the person whose name appears above is duly authorized to execute Contracts on behalf of the firm.

Indicate your Social Security Number **OR** your Federal Tax Identification Number (FTIN). This number shall correspond with the Consultant name indicated above and shall be the same Federal Tax Identification Number under which you report income. **COMPLETE ONLY ONE.**

Federal Tax ID # 54-0913199	**Social Security #**

The Internal Revenue Service (IRS) requires us to obtain certain information from you to meet IRS Form 1099 reporting and filing requirements. If you do not provide your correct FTIN, your payments may be subject to 20% backup withholding. Under penalties of perjury, I certify that the FTIN shown above is correct for the Consultant named.

CH2M Hill, Inc

(Consultant to fill in name and title)

is appointed as the person to whom all official correspondence to Consultant concerning this Contract should be directed.

In accordance with the Federal Acquisition Regulation section 52.219, please check all that apply to your company. Please provide supporting documentation or certification to confirm the status for any categories checked under Small/Diverse Vendors.

[ ] Certified small business*
[ ] Veteran-owned business*
[ ] Service-disabled veteran-owned business*
[ ] HUBZone, 8(a) or disadvantaged business*
[ ] Minority-owned business * *
[ ] Women-owned small business * *
[√] Not a Small Business

* As defined by the Small Business Administration (SBA): www.sba.gov
* * Certified by Progress Energy and as defined by SBA.
Register online at www.progress-energy.com/supplierdiversity

PEF-POD3-NO HEARING EXHIBIT - 00000724

Contract Employee
Code of Ethics Acknowledgment Form

Please go to the following website to review the Progress Energy Code of Ethics prior to signing this Acknowledgment Form. Hard copies are available upon request.

http://www.progress-energy.com/investors/corpgov/codeofethics.asp

I have read the Progress Energy Code of Ethics. I understand that the principles stated in the Code of Ethics represent those of Progress Energy as they relate to the work I perform as an independent contractor (or as an employee of an independent contractor of Progress Energy), and that violating those principles, or the legal and regulatory requirements applicable to my work may result in disciplinary action by my employer. I agree to abide by and support the legal and regulatory requirements applicable to my work. I understand that if I have questions concerning appropriate ethics or relevant legal and regulatory requirements, I should consult with my supervisor.

_____

Signature of Contract Employee

_____

Name of Contract Employee

_____

Date

_____

Social Security Number

_____

Consultant Organization

Consultant shall maintain completed forms. Do not return completed forms unless they are specifically requested by Owner.

CH2M HILL
127 N. First Street
Suite 400
St. Louis, MO 63102
Tel 314-421-0313
Fax 314-421-3927

CH2MHILL

June 19, 2008

Kristin Beck
Corporate Social Responsibility
Progress Energy Service Company, LLC
PO Box 1551
Raleigh, NC 27602

Subject: Progress Energy Greenhouse Gas (GHG) Inventory Assistance
Request No. CPS-0001LB; Contract #349635 – Change Notification

Dear Kristin,

Per your request, CH2M HILL is pleased to present Progress Energy Services Company, LLC (Progress Energy) with a change notification to request additional funding to complete a revised approach to the original scope of work under the above referenced Progress Energy Request and contract number.

Progress Energy originally contracted with CH2M HILL in November 2007 to support development of an entity-wide greenhouse gas (GHG) inventory (Contract No. 349635). The Scope of Work provided in the original contract included development of a detailed analysis of direct and indirect GHG emissions for all of the six major GHGs (CO_2, CH_4, N_2O, PFCs, HFCs, and SF_6). The following tasks were specified:

Task 1 **Develop GHG Inventory Management Plan (IMP).** The GHG Inventory Plan will define the scope of work, roles and responsibilities, project timeline, resource needs for data collection and deliverables. It will also capture key decisions that will be required early in the project, such as operational boundaries; identification of sources that will be included and excluded in the inventory; years to be included for data collection; and the inventory protocol.

Task 2 **Collect Data.** Identified field resources will develop a comprehensive list of GHG emissions sources and will collect operational data required to support the emissions calculations.

Task 3 **Calculate GHG Emissions.** GHG emissions will be calculated and documented on an Excel spreadsheet for each year selected in the GHG Inventory Plan. Benefits from completed or ongoing emissions reductions projects will also be calculated. Once the inventory has been generated, potential de minimis sources will be identified and a baseline will be established. For each source, the spreadsheet will indicate the quality of the calculation or estimation methodology used and an explanation of why this approach was chosen.

Task 4 **Establish Ongoing Implementation Strategy.** The GHG Inventory Core Team will develop the ongoing strategy for collecting, calculating and documenting the annual GHG emissions inventory and carbon offsets. The recommended strategy will be documented for internal management review.

Specific deliverables to be completed under the four tasks were:

1. Conduct an Objectives Workshop/Kickoff Meeting (includes draft and final agenda and presentations)
2. Conduct an Inventory Development Planning Meeting (data gathering planning)
3. Conduct technical approach meetings (two)
4. Develop data collection plan and tool (includes draft and final tool)
5. Provide data gathering technical support
6. Conduct a data gap review (includes summary and review meeting)
7. Develop IMP (includes draft and final Plan)
8. Complete entity-wide GHG emissions inventory (includes draft and final quantification tool)
9. Assist with development of on-going strategy development

As of June 1, 2008, the current budget of $78,900 has been expended with the completion of deliverables 1, 2, 3, 4, and 5 and the partial completion of deliverables 7 and 8. Due to the large amounts of data reviewed and processed for not only the generating facilities, but also the non-generating facilities and the level of technical support rendered deliverables 6 and 9 have not been initiated under the current budget.

To facilitate the completion of the project, additional funding is needed. This change notice serves to document a revised approach to completing the original scope of work (under either of two options provided by Progress Energy) and the additional funding required. We propose the following actions as outlined in the attached revised scope of work. The budget for these two options is also included.

If you have any questions, please feel free to contact me at 314.335.3015 or Jamiyo Mack at 703.376.5180.

Sincerely,
CH2M HILL

Dana French

Lisa A Drinkwater

Dana French, P.E.
Project Manager

Lisa Drinkwater, P.E.
Vice-President

Enclosures

Revised Scope of Work

Option 1 - Limited Consultant Support Approach

Under this option, Progress Energy will bear the responsibility of performing the emissions calculations for the development of the corporate-wide inventory (deliverable 8) using the emissions quantification tool/template created by CH2M HILL.

Specifically, Progress Energy will provide CH2M HILL with several sets of spreadsheets (i.e. a model generating plant, a model set of non-generating facilities, and distribution and transmission sources) populated with source and operational data representative of that collected to-date from these entities. CH2M HILL will finalize the draft GHG emissions calculation template based upon the data provided in these spreadsheets. Progress Energy personnel will complete the development of the facility-based GHG emissions inventories by populating the template with the actual data collected from the generating plants, facilities, and other sources in the data collection forms developed under deliverable 5. Progress Energy personnel will also generate the corporate-wide roll-up of emissions. CH2M HILL will be available for periodic consultation and technical support on emission estimation methodology and the data aggregation approach as well as provide a QA/QC review of the populated emissions quantification spreadsheet.

For deliverable 6, Progress Energy will lead the effort to identify and address data gaps as needed to complete the corporate-wide inventory and finalize the IMP (deliverable 7). CH2M HILL will provide technical support and QA/QC review for the development of the final IMP.

For deliverable 9, Progress Energy will develop an ongoing strategy for annual inventory development. CH2M HILL will be consulted during the development of the strategy for the purpose of review and comment. CH2M HILL expects to spend no more than 10 hours of time on this task.

Assumptions:

- Deliverables will be submitted electronically

Deliverables:

- Final emissions quantification tool/template in Microsoft Excel

Option 2 - Full Consultant Services Approach

Under this option, CH2M HILL will finalize the draft GHG emissions calculation tool/template for developing the corporate-wide inventory (deliverable 8). Progress Energy will provide CH2M HILL with several sets of spreadsheets (i.e. a model generating plant, a model set of non-generating facilities, and distribution and transmission sources) populated with source and operational data representative of that collected to-date from these entities in order to complete the template.

Upon completion of the tool, CH2M HILL will review the emissions quantification tool with Progress Energy personnel for agreement on methodology. Progress Energy will provide CH2M HILL with the completed data collection sheets from the generating plants, non-generating facilities, and distribution and transmission sources. CH2M HILL will complete the facility-based emissions inventory by populating the calculation tool/template with the actual data from the generating plants, facilities, and other sources. CH2M HILL will generate the

entity-wide roll-up of emissions. CH2M HILL will complete a QA/QC review of the populated emissions quantification spreadsheet.

For deliverable 6, CH2M HILL will complete a data gaps analysis of the data and information received. Progress Energy will lead the effort to address the data gaps, if possible, and provide feedback to CH2M HILL. CH2M HILL will provide technical support during the period in which Progress Energy personnel are addressing the data gaps. After data gaps have been addressed, CH2M HILL will finalize the draft IMP developed under deliverable 7 based upon the information received from Progress Energy personnel.

Under deliverable 9, Progress Energy will develop an ongoing strategy for annual inventory development. CH2M HILL will provide technical support during the development of the strategy for the purpose of review and comment. CH2M HILL has estimated to spend no more than 10 hours of time on this activity.

[redacted]

Deliverables:

- Final emissions quantification tool/template in Microsoft Excel
- Data gaps analysis summary in Microsoft Excel
- Final IMP in Microsoft Word
- Final corporate-wide GHG emissions inventory in Microsoft Excel

Schedule

CH2M HILL expects to proceed with the revised scope of work immediately upon being notified of the accepted option by Progress Energy. Option 1 would be completed four weeks after the notice to proceed. Option 2 is anticipated to conclude by August 31, 2008 if final facility-level data is submitted no later than June 30, 2008.

[redacted]

Option 1	Hours	Labor Category	Rate	Amount
Final Emissions Quantification Tool	[redacted]			
Technical Support				
Project Management				
Total:				$17,060.00

Option 2	Hours	Labor Category	Rate	Amount
Final Emissions Quantification Tool, Data Population, and Final Inventory	[redacted]			
Data Gaps Analysis				
Final IMP				
Technical Support				
Project Management				
Total:				$41,636.00

A	B	C	D	E	F	G	H	I
	Option 1		Option 2		Option 3		Other Options	
	Time and Materials	Not to Exceed	Time and Materials	Not to Exceed	Time and Materials	Not to Exceed	Time and Materials	Not to Exceed
[redacted]	$	$	$	$	$	$		
	$		$		$			
	$		$		$			
		$	$	$		$	$	$
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PEF-POD3-NO3-048

HEARING EXHIBIT - 00000730

19

PEF's Response to Staff's Fourth Request for Production of Documents (Nos. 5 - 6)

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No. 080007-EI
	Dated: September 23, 2008

PROGRESS ENERGY FLORIDA'S RESPONSE TO STAFF'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 5-6)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.350, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Fourth Request for Production of Documents (Nos. 5-6):

RESPONSES

5. **Please refer to the testimony and exhibits of Lori Cross dated August 4, 2008. Please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-8E. Please cite all sources and include the rationale for using the particular capital structure and cost rates.**

Response: See Attachment 5-1.

6. **Please refer to the testimony and exhibits of Lori Cross dated August 4, 2008. Please provide a reconciliation, explanation, and possible corrected pages for 1, 2, 7, and 9 of forms 42-8E. Please cite all sources and include the rationale for using the particular capital structure and cost rates. (Pages 1 & 2 have an unexplained "Other" amount for Line 7c and pages 7 & 9 contain an unexplained difference for the amount on Lines 7a/7b on May 2008 and May-December 2008, respectively).**

Response: A reconciliation was performed in May 2008 to ensure that the depreciation rates that were being utilized on the ECRC schedules agreed to the plant accounting system. All of the ECRC asset depreciation rates agreed to the plant system except for the two exceptions noted below for Page 1 and Page 7.

Page 1: The Pipeline Integrity Management (PIM) program (42-8E page1), had two assets (Alderman Road Fence and Pipeline Leak Detection) that were in-service and both being depreciated using a 3.07% rate. This rate agreed to the plant system for the Alderman Road Fence. However, the Pipeline Leak Detection portion of the program had been classified in the plant system as Boiler Plant Equipment which has a depreciation rate of 4.10% based on the 2005 Rate Case Settlement Agreement (Order

No. PSC-05-0945-S-EI). Therefore, in May the assets for PIM were separated on the Capital Program Detail (Exhibit LC-2, pg. 2) and the depreciation was adjusted for January 2006 through April 2008. This adjustment calculation appears on Attachment 6-1 and the adjustment is included in Line 8e of Project 3.1b of the Capital Program Detail. Because the Net Investment would have been affected by the depreciation adjustments in the prior periods, the return on debt and equity was also adjusted. These adjustment calculations also appear on Attachment 6-1 and the adjustments are included in Line 7c of Project 3.1b of the Capital Program Detail. Attachment 6-2 through 6-4 include the adjusted schedules for the Pipeline Leak Detection project and Attachment 6-5 through 6-7 show the Alderman Road Fence project using the same 3.07% rate but separated for purposes of the analysis.

Page 2: This amount, as documented in footnote (G) represents the portion of the return on investment from the Turner Tank 8 Above Ground Storage double bottoming project that PEF impaired and determined appropriate to refund to the customer. Refer to the following schedules in Attachments (6-17 through 6-24):

- Refund Analysis – provides the allocation of costs to the impaired portion of the asset
- Impairment Detail Summary – provides a summary of the costs provided by the business service group
- True Up Filings – 42-8A pg2 schedules for the following years
    - 2003
    - 2004
    - 2005
- True Up Filings – Cap Program Detail schedules for the following years
    - 2006
    - 2007
- Estimated / Actual Filing – Cap Program Detail schedule
    - 2008

Page 7: Also, each of the sites that are part of the CAIR/CAMR – Peaking program (CAIR CT's, 42-8E page 7), were classified in the plant system as Prime Movers which have various depreciation rates based on the plant sites per the 2005 Rate Case Settlement Agreement. However, the ECRC schedules were being depreciated using the rates for the Misc. Power Plant Equipment group so the depreciation was adjusted for these assets from their in-service dates in November 2007/January 2008 through April 2008. This adjustment calculation appears on Attachment 6-8 and the adjustments are included in Line 8a of Projects 7.2a through 7.2h of the Capital Program Detail (Exhibit LC-2, pg. 2) with the current month actual depreciation expense. Because the Net Investment would have been affected by the depreciation adjustments in the prior periods, the return on debt and equity was also adjusted. These adjustment calculations appear on Attachment 6-8 and the adjustments are included in Lines 7a and 7b of Projects 7.2a through 7.2h of the Capital Program Detail with the current month return. Attachments 6-9 through 6-16 include adjusted 2007 and 2008 schedules for the CAIR CTs projects from the Capital Program Detail.

Page 9: This page summarizes the capital expenditures for the CAIR Crystal River project that earns AFUDC. Projects earning AFUDC do not recover return on capital from the ratepayers until the assets have been placed in service. For CAIR Crystal River, the only assets included as in-service in 2008 are the Vehicle Barrier System/Access Road and Low NOx Burner CR4 which appear on the Capital Program Detail as Projects 7.4a and 7.4b. Therefore, the only return that appears on 42-8E Page 9 is the return for these two assets which is calculated on the Capital Program Detail.

SERVED this 23rd day of September, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko, Esquire
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

Progress Energy Florida
Captial Structure and Rate of Return

EFFECTIVE 1/1/2006 FOR FORECASTS AND ACTUALS
Per Settlement Agreement dated 8/23/05 - D-1a as filed with 11.75% Equity Docket 050078-EI Fully Adj'd Retail

	2006 Test Yr $000's	Ratio	Cost Rate	Weighted Cost	38.575%	Pretax
CE	$ 2,684,417	57.83%	11.75%	6.80%	after tax	11.06%
PS	25,044	0.54%	4.51%	0.02%	after tax	0.04%
LTD - F	1,520,653	32.76%	5.73%	1.88%	pretax	1.88%
LTD - V	-	0.00%	0.00%	0.00%	pretax	0.00%
STD	25,148	0.54%	4.04%	0.02%	pretax	0.02%
CD-active	101,979	2.20%	5.92%	0.13%	pretax	0.13%
CD-Inact	-	0.00%	0.00%	0.00%	pretax	0.00%
ITC-Equity	13,485	0.29%	11.68%	0.03%	after tax	0.06%
ITC-Debt	7,568	0.16%	5.73%	0.01%	pretax	0.01%
DEF TX	309,400	6.67%	0.00%	0.00%	after tax	0.00%
DEF TX	(46,088)	-0.99%	0.00%	0.00%	after tax	0.00%
	4,641,606	100.00%		8.89%		13.19%
		100.00%				

Total Debt	2.04%	pretax	**2.04%**	**pretax**
Total Equity	6.85%	after tax	**11.16%**	**pretax**

Effective Tax Rate	**38.575%**
Income Tax Multiplier	1.628002

Pipeline Integrity Management (PIM) True up for Depreciation Rate Correction
Progress Energy Florida

Depreciation Rate True up

2006 Projects (42-8a pg. 1 of 11 line 8a)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	1,042		
Leak Detection	108,266		
Total	109,308	82,110	27,198

2007 Projects (42-8a pg. 1 of 11 line 8a)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	1,042		
Leak Detection	108,266		
Total	109,308	82,110	27,198

2008 Projects (42-8a pg. 1 of 11 line 8a)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	347		
Leak Detection	56,089		
Total	56,436	27,370	9,066

May 2008 True up for Depreciation: 63,462 (as noted on Schedule 42-8E, pg. 1 of 13, line 8f)

Return on Average Net Investment True up (true up due to depreciation change):

2006 Projects (42-8a pg. 1 of 11 line 7a)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	3,582		
Leak Detection	278,764		
Total	282,346	283,865	(1,519)

2007 Projects (42-8a pg. 1 of 11 line 7a)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	3,466		
Leak Detection	266,681		
Total	270,147	275,710	(5,569)

2008 Projects (42-8a pg. 1 of 11 line 7a)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	1,129		
Leak Detection	86,209		
Total	87,338	90,578	(3,240)

May 2008 True up for Leak Detection: (10,322) (A)

2006 Projects (42-8a pg. 1 of 11 line 7b)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	655		
Leak Detection	50,957		
Total	51,612	51,889	(277)

2007 Projects (42-8a pg. 1 of 11 line 7b)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	684		
Leak Detection	48,748		
Total	49,382	50,399	(1,017)

2008 Projects (42-8a pg. 1 of 11 line 7b)	Corrected Amount	Booked Amount	True up Needed
Alderman Road Fence	206		
Leak Detection	15,759		
Total	15,965	16,557	(592)

May 2008 True up for Leak Detection: (1,886) (A)

Sum of (A) = (12,208) As noted on schedule 42-8E, pg 1 of 13, line 7c

HEARING EXHIBIT - 00000736

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

Form 42-5A
Page 1 of 11

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
(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	$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	(88,814)	(97,837)	(106,860)	(115,884)	(124,787)	(133,730)	(142,753)	(151,776)	(160,799)	(169,822)	(178,846)	(187,867)	(196,890)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$2,552,022	2,542,999	2,533,976	2,524,952	2,516,029	2,506,906	2,497,888	2,488,860	2,479,837	2,470,813	2,461,791	2,452,769	2,443,747	
6	Average Net Investment		2,547,510	2,538,487	2,529,464	2,520,441	2,511,418	2,502,396	2,493,371	2,484,348	2,475,325	2,466,302	2,457,280	2,448,258	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)	11.16%	23,682	23,608	23,534	23,440	23,356	23,272	23,188	23,104	23,021	22,937	22,853	22,769	$278,764
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%	4,331	4,318	4,300	4,286	4,268	4,254	4,239	4,223	4,208	4,193	4,177	4,162	50,957
8	Investment Expenses														
	a. Depreciation (C)	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	108,266
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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)		4,376	4,361	4,346	4,330	4,314	4,299	4,283	4,267	4,252	4,236	4,221	4,206	51,489
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		41,421	41,308	41,181	41,077	40,962	40,847	40,732	40,617	40,503	40,388	40,273	40,159	489,475
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		41,421	41,308	41,191	41,077	40,962	40,847	40,732	40,617	40,503	40,388	40,273	40,159	489,475
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (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)		32,742	32,661	32,580	32,470	32,379	32,288	32,197	32,106	32,016	31,929	31,834	31,743	386,910
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$32,742	$32,661	$32,580	$32,470	$32,379	$32,288	$32,197	$32,106	$32,016	$31,929	$31,834	$31,743	$386,910

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity components of capital structure of 8.55%, and statutory income tax rate of 38.575% (expansion factor of 1.626002). Based on 2006 rate case settlement in Dkt. 060078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2006 rates on Exhibit 2 in the 2006 rate case settlement in Dkt. 060078-EI.
(D) Lines 2 + 3 x 89% @ .021084 x 1/12 + 11%@ .017983 x 1/12. Rate from Property Tax Administration Department, based on plant allocation reported and 2004 Actual Property Tax Millage Rate.
(E) Line 9b x Line 10 x 1.00000 line loss multiplier. None for this period.
(F) Line 9b x Line 11

Source:
Line 6c Based on 2006 rate case settlement in Dkt. 060078-EI.

HEARING EXHIBIT - 00000737

Form 42-8A
Page 1 of 13

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
(In Dollars)

Line	Description	Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	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	$3,648,636	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	(3,196,889)	(205,911)	(214,933)	(223,956)	(232,978)	(242,000)	(251,022)	(260,044)	(269,066)	(278,089)	(287,111)	(296,133)	(305,156)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	2,448,747	2,434,725	2,425,703	2,416,680	2,407,658	2,398,636	2,389,614	2,380,592	2,371,570	2,362,547	2,353,525	2,344,503	2,335,481	
6	Average Net Investment		2,439,236	2,429,214	2,421,192	2,412,169	2,403,147	2,394,125	2,386,103	2,376,081	2,367,059	2,358,036	2,348,014	2,338,992	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)	11.19%	22,686	22,601	22,517	22,433	22,349	22,265	22,181	22,098	22,014	21,930	21,846	21,762	$268,881
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%	4,147	4,131	4,116	4,101	4,085	4,070	4,055	4,039	4,024	4,008	3,993	3,978	48,748
8	Investment Expenses														
	a. Depreciation (C)	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	108,266
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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)		(34,830)	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	(4,698)
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		11,034	37,559	37,460	37,361	37,262	37,162	37,063	36,964	36,865	36,766	36,666	36,567	418,726
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		11,034	37,559	37,460	37,361	37,262	37,162	37,063	36,964	36,865	36,766	36,666	36,567	418,726
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)		8,722	29,689	29,611	29,532	29,454	29,376	29,297	29,219	29,140	29,061	28,983	28,905	330,988
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,722	$29,689	$29,611	$29,532	$29,454	$29,376	$29,297	$29,219	$29,140	$29,061	$28,983	$28,905	$330,988

Notes:
(A) N/A
(B) Line 6 x 11.185% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.88%, and Statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2006 rate case settlement in Dkt. 060078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2006 rates on Exhibit 2 in the 2006 rate case settlement in Dkt. 060078-EI.
(D) Lines 2 x 66% @ .008313 x 1/12 + 11%@ .007286 x 1/12. Rate from Property Tax Administration Department, based on plant allocation reported and 2005 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 6c Based on 2006 rate case settlement in Dkt. 060078-EI.

HEARING EXHIBIT - 00000738

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 3b)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 08	Actual February 08	Actual March 08	Actual April 08	End of Period Total
1	Investments						
	a. Expenditures/Additions		$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	
	c. Retirements		0	0	0	0	
	d. Other (A)		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	
3	Less: Accumulated Depreciation	(305,188)	(314,177)	(323,199)	(332,222)	(341,244)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$2,335,481	2,326,659	2,317,637	2,308,614	2,299,592	
6	Average Net Investment		2,330,970	2,321,948	2,312,926	2,303,803	
7	Return on Average Net Investment						
	a. Equity Component Grossed Up For Taxes (B) 11.16%		21,676	21,594	21,510	21,428	$86,209
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		3,965	3,947	3,932	3,917	15,759
8	Investment Expenses						36,089
	a. Depreciation (C) 4.10%		9,022	9,022	9,022	9,022	0
	b. Amortization		0	0	0	0	N/A
	c. Dismantlement		N/A	N/A	N/A	N/A	7,219
	d. Property Taxes (D)		1,806	1,806	1,806	1,806	0
	e. Other		0	0	0	0	
9	Total System Recoverable Expenses (Lines 7 + 8)		36,469	36,369	36,269	36,170	145,276
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		36,469	36,369	36,269	36,170	145,276
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)		0.79046	0.79046	0.79046	0.79046	
12	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)		28,830	28,747	28,668	28,591	114,834
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$28,830	$28,747	$28,668	$28,591	$114,834

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 2008 rate case settlement in Dkt. 080078-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) Lines 2 x 89% @ .006313 x 1/12 + 11%@ .007298 x 1/12. Rate 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

Source:
Line 8c Based on 2008 rate case settlement in Dkt. 080078-EI.

HEARING EXHIBIT - 00000739

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
(In Dollars)

Line	Description	Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	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	$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	(1,324)	(1,412)	(1,500)	(1,588)	(1,676)	(1,763)	(1,851)	(1,939)	(2,027)	(2,115)	(2,202)	(2,288)	(2,375)	
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)	$32,628	32,540	32,452	32,364	32,276	32,189	32,101	32,013	31,925	31,837	31,750	31,663	31,577	
6	Average Net Investment		32,584	32,496	32,408	32,320	32,232	32,145	32,057	31,969	31,881	31,794	31,707	31,620	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		303	302	301	301	300	299	298	297	296	296	295	294	$3,582
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		55	55	55	55	55	55	54	54	54	54	54	54	655
8	Investment Expenses														
	a. Depreciation (C) 3.07%		87	87	87	87	87	87	87	87	87	87	87	87	1,042
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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)		56	56	56	56	55	55	55	55	55	55	54	54	662
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		501	500	499	498	497	496	495	493	492	491	490	489	5,941
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		501	500	499	498	497	496	495	493	492	491	490	489	5,941
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)		396	395	394	394	393	392	391	390	389	388	387	387	4,696
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$396	$395	$394	$394	$393	$392	$391	$390	$389	$388	$387	$387	$4,696

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 6.88%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2006 rate case settlement in Dkt. 060078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2006 rates on Exhibit 2 in the 2006 rate case settlement in Dkt. 060078-EI.
(D) Lines 2 + 3 x 88% @ .021054 x 1/12 + 11%@ .017308 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2004 Actual Property Tax Milage Rate.
(E) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(F) Line 9b x Line 11

Source:
Line 8d Based on 2006 rate case settlement in Dkt. 060078-EI.

HEARING EXHIBIT - 00000740

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
(In Dollars)

Line	Description	Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	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	$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	($3,375)	(2,482)	(2,649)	(2,636)	(2,722)	(2,809)	(2,896)	(2,983)	(3,070)	(3,157)	(3,244)	(3,330)	(3,417)	
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)	31,577	31,490	31,403	31,316	31,230	31,143	31,056	30,969	30,882	30,795	30,708	30,622	30,535	
6	Average Net Investment		31,534	31,447	31,360	31,273	31,186	31,099	31,012	30,926	30,839	30,752	30,665	30,578	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		293	292	292	291	290	289	288	288	287	286	285	284	$3,466
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		54	53	53	53	53	53	53	53	52	52	52	52	634
8	Investment Expenses														
	a. Depreciation (C) 3.07%		87	87	87	87	87	87	87	87	87	87	87	87	1,042
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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)		(26,802)	23	23	23	23	23	23	23	23	23	23	23	(26,347)
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		(26,168)	456	455	454	453	452	451	450	449	448	447	446	(21,207)
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		(26,168)	456	455	454	453	452	451	450	449	448	447	446	(21,207)
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)		(20,685)	360	360	359	358	357	356	356	355	354	353	353	(16,763)
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		($20,685)	$360	$360	$358	$358	$357	$356	$356	$355	$354	$353	$353	($16,763)

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 2006 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2006 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Lines 2 x 89% @ .006313 x 1/12 + 11%@ .007258 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2005 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

HEARING EXHIBIT - 00000741

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	End of Period Total
1	Investments							
	a. Expenditures/Additions			$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	
	c. Retirements			0	0	0	0	
	d. Other (A)			0	0	0	0	
2	Plant-in-Service/Depreciation Base		$33,952	33,952	33,952	33,952	33,952	
3	Less: Accumulated Depreciation		(3,417)	(3,604)	(3,791)	(3,978)	(3,784)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$30,535	30,448	30,361	30,274	30,188	
6	Average Net Investment			30,492	30,405	30,318	30,231	
7	Return on Average Net Investment							
	a. Equity Component Grossed Up For Taxes (B)	11.16%		284	283	282	281	$1,129
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		52	52	52	51	208
8	Investment Expenses							
	a. Depreciation (C)	3.07%		87	87	87	87	347
	b. Amortization			0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			23	23	23	23	93
	e. Other			0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			445	445	444	443	1,777
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			445	445	444	443	1,777
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.79046	0.79046	0.79046	0.79046	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			352	352	351	350	1,405
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$352	$352	$351	$350	$1,405

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 1.628302). Based on 2006 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) 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 2005 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

HEARING EXHIBIT - 00000742

CAIR CTs True Up for Depreciation Rate Correction
Progress Energy Florida

Depreciation Rate True Up *(Projects 7.2a through 7.2h, Line 8a, of the Capital Program Detail Support, Exhibit LC-2, pg. 9 thru 12)*

	2007 (Nov - Dec)			2008 (Jan - Apr)			Total True Up	
Site	Booked Amount	Corrected Amount	True Up Needed	Site	Booked Amount	Corrected Amount	True Up Needed	Needed in May Close
Avon Park	384	281	(103)	Avon Park	970	711	(259)	(362) A
Bartow	1,386	1,072	(314)	Bartow	3,906	3,021	(885)	(1,199) A
Bayboro	715	619	(96)	Bayboro	2,011	1,740	(271)	(367) A
Debary	373	424	51	Debary	870	990	120	171 A
Higgins	-	0	0	Higgins	3,602	924	(2,678)	(2,678) A
Int City	2,291	1,076	(1,215)	Int City	6,524	3,064	(3,460)	(4,675) A
Turner	766	435	(331)	Turner	2,133	1,212	(921)	(1,252) A
Suwannee	-	0	0	Suwannee	4,740	2,342	(2,398)	(2,398) A

Return of Average Net Investment Equity Component True Up Due to Depreciation Change *(Projects 7.2a through 7.2h, Line 7a, of the Capital Program Detail Support, Exhibit LC-2, pg. 9 thru 12)*

	2007 (Nov - Dec)			2008 (Jan - Apr)			Total True Up	
Site	Booked Amount	Corrected Amount	True Up Needed	Site	Booked Amount	Corrected Amount	True Up Needed	Needed in May Close
Avon Park	3,028	3,029	1	Avon Park	6,046	6,055	9	10 B
Bartow	4,631	4,633	2	Bartow	10,018	10,046	28	30 B
Bayboro	3,230	3,231	1	Bayboro	7,307	7,316	9	10 B
Debary	1,250	1,250	-	Debary	3,223	3,218	(5)	(5) B
Higgins	5,586	5,586	-	Higgins	11,673	11,717	44	44 B
Int City	6,040	6,050	10	Int City	12,694	12,804	110	120 B
Turner	2,316	2,319	3	Turner	4,840	4,869	29	32 B
Suwannee	6,410	6,410	-	Suwannee	13,950	13,990	40	40 B

Return of Average Net Investment Debt Component True Up Due to Depreciation Change *(Projects 7.2a through 7.2h, Line 7b, of the Capital Program Detail Support, Exhibit LC-2, pg. 9 thru 12)*

	2007 (Nov - Dec)			2008 (Jan - Apr)			Total True Up	
Site	Booked Amount	Corrected Amount	True Up Needed	Site	Booked Amount	Corrected Amount	True Up Needed	Needed in May Close
Avon Park	554	554	-	Avon Park	1,105	1,107	2	2 C
Bartow	846	847	1	Bartow	1,831	1,836	5	6 C
Bayboro	590	591	1	Bayboro	1,336	1,337	1	2 C
Debary	229	228	(1)	Debary	589	588	(1)	(2) C
Higgins	1,021	1,021	-	Higgins	2,134	2,142	8	8 C
Int City	1,104	1,106	2	Int City	2,320	2,340	20	22 C
Turner	423	424	1	Turner	885	890	5	6 C
Suwannee	1,172	1,172	-	Suwannee	2,550	2,557	7	7 C

Tickmarks:

A Included in the May total amount of Line 8a of Projects 7.2a through 7.2h of the Capital Program Detail Support (Exhibit LC-2, pg. 9 thru 12)
B Included in the May total amount of Line 7a of Projects 7.2a through 7.2h of the Capital Program Detail Support (Exhibit LC-2, pg. 9 thru 12)
C Included in the May total amount of Line 7b of Projects 7.2a through 7.2h of the Capital Program Detail Support (Exhibit LC-2, pg. 9 thru 12)

HEARING EXHIBIT - 00000743

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2008
CAIR CTs (Project 7.2 Recap)

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

ALL Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$679	$356	$48,024	($2,614)	$48,015	$22,063	$1,095	$6,932	$429	$12,652	$3,072	$16,485	$156,486
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	156,612	16,485	
	c. Retirements		0	0	0	0	0	0	0	0	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	156,612	176,097	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(88)	(281)	
4	CWIP - Non-Interest Bearing	16,611	17,290	17,646	65,670	64,356	112,371	135,334	136,429	143,360	143,889	156,541	0	1	
5	Net Investment (Lines 2 + 3 + 4)	$16,611	17,290	17,646	65,670	64,356	112,371	135,334	136,429	143,360	143,889	156,541	156,524	175,816	
6	Average Net Investment		17,101	17,768	42,448	65,063	88,364	123,863	135,881	139,894	143,625	150,215	156,032	167,670	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		158	165	395	611	822	1,152	1,264	1,301	1,336	1,397	1,470	1,559	$11,630
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.06%		29	30	72	112	150	211	231	238	244	256	269	285	2,129
8	Investment Expenses														
	a. Depreciation 1.32%		0	0	0	0	0	0	0	0	0	0	88	194	281
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009184		0	0	0	0	0	0	0	0	0	0	122	135	257
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		188	195	467	722	972	1,362	1,495	1,539	1,580	1,652	1,948	2,173	14,294
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		188	195	467	722	972	1,362	1,495	1,539	1,580	1,652	1,948	2,173	14,294

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$6,891	$14,305	$14,503	$8,816	$16,002	$15,630	$1,381	$615	$418	$5,362	$2,823	$21,015	$108,060
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	244,873	21,015	
	c. Retirements		0	0	0	0	0	0	0	0	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	244,973	265,988	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(338)	(1,072)	
4	CWIP - Non-Interest Bearing	167,937	154,918	170,223	183,726	202,542	218,543	234,374	235,754	236,369	236,787	242,149	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$167,937	154,918	170,223	183,726	202,542	218,543	234,374	235,754	236,369	236,787	242,149	244,635	264,916	
6	Average Net Investment		161,423	172,570	188,474	198,134	210,842	226,458	235,064	236,062	236,578	239,468	243,392	254,775	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,501	1,600	1,734	1,843	1,958	2,105	2,186	2,195	2,200	2,227	2,264	2,368	$24,184
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.06%		274	293	317	337	358	385	400	401	402	407	414	433	4,421
8	Investment Expenses														
	a. Depreciation 3.31%		0	0	0	0	0	0	0	0	0	0	338	734	1,072
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009313		0	0	0	0	0	0	0	0	0	0	170	184	354
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,776	1,893	2,051	2,179	2,316	2,491	2,586	2,597	2,602	2,634	3,186	3,720	30,030
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,776	1,893	2,051	2,179	2,316	2,491	2,586	2,597	2,602	2,634	3,186	3,720	30,030

HEARING EXHIBIT - 00000744

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2008 through December 2008
CAIR CTs (Project 7.3 Recap)

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$434	$18,275	$6,812	$188	$6,313	$19,282	$1,000	$96	$497	$4,881	$15,320	$24,955	$96,905
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	171,525	24,946	
	c. Retirements		0	0	0	0	0	0	0	0	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	171,525	196,490	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(188)	(619)	
4	CWIP - Non-Interest Bearing	108,476	108,910	117,185	123,997	124,185	130,478	149,760	150,760	150,826	151,324	156,205	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$108,476	108,910	117,185	123,997	124,185	130,478	149,760	150,760	150,826	151,324	156,205	171,338	195,862	
6	Average Net Investment		108,693	113,048	120,591	124,091	127,322	140,119	150,260	150,793	151,075	153,764	163,771	183,600	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	936	1,014	1,121	1,154	1,184	1,303	1,397	1,402	1,405	1,430	1,523	1,707	$15,579
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.84%	171	185	205	211	216	238	255	256	257	261	278	312	2,848
8	Investment Expenses														
	a. Depreciation	2.83%	0	0	0	0	0	0	0	0	0	0	188	431	619
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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	0	0	0	0	0	0	0	0	0	0	119	136	255
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,108	1,200	1,327	1,365	1,401	1,541	1,653	1,658	1,662	1,691	2,108	2,586	19,300
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,108	1,200	1,327	1,365	1,401	1,541	1,653	1,658	1,662	1,691	2,108	2,586	19,300

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$180	$696	$842	$4,230	$5,369	$24,954	$3,414	$4,021	$4,976	$3,584	$7,794	$22,819	$82,783
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	68,631	22,819	
	c. Retirements		0	0	0	0	0	0	0	0	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	68,631	88,450	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(180)	(424)	
4	CWIP - Non-Interest Bearing	3,669	3,849	4,539	5,180	9,510	14,879	39,833	43,247	47,267	52,243	55,838	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$3,669	3,849	4,539	5,180	9,510	14,879	39,833	43,247	47,267	52,243	55,838	68,452	88,027	
6	Average Net Investment		3,759	4,194	4,859	7,345	12,195	27,356	41,540	45,257	49,755	54,041	59,845	74,739	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	35	39	45	68	113	254	386	421	463	503	555	695	$3,578
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.84%	6	7	8	12	21	47	71	77	85	92	101	127	654
8	Investment Expenses														
	a. Depreciation	3.39%	0	0	0	0	0	0	0	0	0	0	180	244	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	0.008670	0	0	0	0	0	0	0	0	0	0	46	62	108
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		41	46	53	81	134	301	457	498	547	594	882	1,128	4,764
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		41	46	53	81	134	301	457	498	547	594	882	1,128	4,764

HEARING EXHIBIT - 00000745

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
CAIR CTs (Project 7.3 Recap)

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$6,044	$20,905	$103,846	$5,075	$15,842	$15,157	$18,001	$236	$2,673	$4,009	$23,529	$5,554	$220,471
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0		
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	$89,886	95,930	116,836	220,480	225,556	241,197	256,354	274,355	274,592	277,265	281,274	304,803	310,357	
5	Net Investment (Lines 2 + 3 + 4)	$89,886	95,930	116,836	220,480	225,556	241,197	256,354	274,355	274,592	277,265	281,274	304,803	310,357	
6	Average Net Investment		92,908	106,382	168,658	223,018	233,376	248,776	265,355	274,474	275,928	279,269	293,038	307,580	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	864	989	1,569	2,074	2,170	2,314	2,468	2,553	2,566	2,597	2,725	2,860	$25,749
	b. Debt Component (Line 6 x 2.67% x 1/12)	2.84%	168	181	287	379	397	423	451	467	469	475	498	523	4,707
8	Investment Expenses														
	a. Depreciation	1.00%	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	0.008313	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)		1,032	1,170	1,855	2,453	2,567	2,737	2,919	3,019	3,035	3,072	3,223	3,383	30,456
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,032	1,170	1,855	2,453	2,567	2,737	2,919	3,019	3,035	3,072	3,223	3,383	30,456

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$1,503	$1,280	$39,871	$8,860	$80,520	$12,983	$2,121	$14,777	$5,025	$35,754	$2,666	$2,060	$207,248
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	326,868	2,060	
	c. Retirements		0	0	0	0	0	0	0	0	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	326,868	327,928	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(357)	(1,076)	
4	CWIP - Non-Interest Bearing	$120,689	122,193	123,483	163,354	171,994	252,513	265,496	267,617	282,393	287,416	323,172	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$120,689	122,193	123,483	163,354	171,994	252,513	265,496	267,617	282,393	287,416	323,172	326,511	326,852	
6	Average Net Investment		121,432	122,823	143,398	167,664	212,253	259,005	266,556	275,005	284,905	305,295	324,341	326,182	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	1,129	1,142	1,334	1,559	1,974	2,409	2,479	2,558	2,650	2,839	3,036	3,033	$26,122
	b. Debt Component (Line 6 x 2.67% x 1/12)	2.84%	288	289	244	285	361	440	453	468	484	519	691	553	4,775
8	Investment Expenses														
	a. Depreciation	2.83%	0	0	0	0	0	0	0	0	0	0	357	719	1,076
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007814	0	0	0	0	0	0	0	0	0	0	207	208	415
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,336	1,351	1,577	1,844	2,335	2,849	2,932	3,025	3,134	3,358	4,132	4,515	32,388
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,336	1,351	1,577	1,844	2,335	2,849	2,932	3,025	3,134	3,358	4,132	4,515	32,388

HEARING EXHIBIT - 00000746

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2007 through December 2007
CAIR CTs (Project 7.2 Recap)

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$3,315	$1,866	$7,945	$17,300	$27,779	$14,957	$7,239	$9,736	$24,061	($1,856)	$7,785	$844	$121,173
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	126,574	844	
	c. Retirements		0	0	0	0	0	0	0	0	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	126,574	127,418	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(145)	(435)	
4	CWIP - Non-Interest Bearing	5,248	9,560	11,426	19,370	36,670	64,449	79,406	86,646	96,383	120,444	118,788	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$5,248	9,560	11,426	19,370	36,670	64,449	79,406	86,646	96,383	120,444	118,788	126,429	126,983	
6	Average Net Investment		7,902	10,493	15,398	28,020	50,560	71,928	83,026	91,514	108,414	119,616	122,609	126,706	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		73	98	143	261	470	669	772	851	1,008	1,112	1,140	1,178	$7,777
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		13	18	26	48	86	122	141	156	184	203	208	215	1,422
8	Investment Expenses														
	a. Depreciation 2.74%		0	0	0	0	0	0	0	0	0	0	145	291	435
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.000974		0	0	0	0	0	0	0	0	0	0	95	95	190
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		87	115	169	308	556	791	913	1,007	1,193	1,315	1,588	1,780	9,823
	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		87	115	169	308	556	791	913	1,007	1,193	1,315	1,588	1,780	9,823

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$1,890	$18,913	$7,205	$8,244	$156,465	$48,680	$9,222	$51,804	$8,998	$8,911	$9,316	$33,158	$362,806
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	9,336	11,226	30,139	37,344	45,588	202,053	250,733	259,955	311,759	320,756	329,367	338,683	371,841	
5	Net Investment (Lines 2 + 3 + 4)	$9,336	11,226	30,139	37,344	45,588	202,053	250,733	259,955	311,759	320,756	329,367	338,683	371,841	
6	Average Net Investment		10,281	20,682	33,741	41,466	123,820	226,393	255,344	285,857	316,257	325,061	334,025	355,262	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		96	192	314	386	1,152	2,105	2,375	2,658	2,941	3,023	3,106	3,304	$21,652
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		17	35	57	70	210	385	434	486	538	553	568	604	3,956
8	Investment Expenses														
	a. Depreciation 2.13%		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 0.000484		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)		113	228	371	456	1,362	2,490	2,809	3,144	3,479	3,576	3,674	3,908	25,610
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		113	228	371	456	1,362	2,490	2,809	3,144	3,479	3,576	3,674	3,908	25,610

HEARING EXHIBIT - 00000747

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 - 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	End of Period Total
1	Investments						
	a. Expenditures/Additions		($14,948)	$604	$0	$0	($14,343)
	b. Clearings to Plant		(14,948)	604	0	0	
	c. Retirements		0	0	0	0	
	d. Other		0	0	0	0	
2	Plant-in-Service/Depreciation Base	$176,067	161,150	161,754	161,754	161,754	
3	Less: Accumulated Depreciation	(201)	(468)	(637)	(816)	(993)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$175,916	160,681	161,117	160,940	160,762	
6	Average Net Investment		168,254	160,904	161,028	160,851	
7	Return on Average Net Investment						
	a. Equity Component Grossed Up For Taxes 11.16%		1,565	1,496	1,498	1,496	$6,055
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		286	274	274	273	1,107
8	Investment Expenses						
	a. Depreciation 1.32%		177	178	178	178	711
	b. Amortization		0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.000194		123	124	124	124	495
	e. Other		0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,152	2,072	2,073	2,071	8,368
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,152	2,072	2,073	2,071	8,368

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	End of Period Total
1	Investments						
	a. Expenditures/Additions		$4,344	$4,096	$853	$266	$9,369
	b. Clearings to Plant		4,344	4,096	853	266	
	c. Retirements		0	0	0	0	
	d. Other		0	0	0	0	
2	Plant-in-Service/Depreciation Base	$265,845	270,331	274,428	275,080	275,347	
3	Less: Accumulated Depreciation	(1,672)	(1,817)	(2,574)	(3,333)	(4,092)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$264,916	268,514	271,854	271,747	271,254	
6	Average Net Investment		266,715	270,184	271,801	271,501	
7	Return on Average Net Investment						
	a. Equity Component Grossed Up For Taxes 11.16%		2,480	2,513	2,526	2,525	$10,046
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		453	459	462	462	1,836
8	Investment Expenses						
	a. Depreciation 3.31%		746	757	758	759	3,021
	b. Amortization		0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.000313		187	190	191	191	758
	e. Other		0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,867	3,919	3,939	3,937	15,662
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		3,867	3,919	3,939	3,937	15,662

HEARING EXHIBIT - 00000748

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 - BAYBORO (Project 7.2c)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	End of Period Total
1	Investments							
	a. Expenditures/Additions			$403	$2,104	$0	$0	$2,506
	b. Clearings to Plant			403	2,104	0	0	
	c. Retirements			0	0	0	0	
	d. Other			0	0	0	0	
2	Plant-In-Service/Depreciation Base		$196,440	196,884	198,988	198,988	198,988	
3	Less: Accumulated Depreciation		(519)	(1,050)	(1,488)	(1,922)	(2,358)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$195,922	195,834	197,502	197,066	196,630	
6	Average Net Investment			195,848	196,668	197,284	196,848	
7	Return on Average Net Investment							
	a. Equity Component Grossed Up For Taxes	11.16%		1,821	1,829	1,835	1,831	$7,316
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.64%		333	334	335	335	1,337
8	Investment Expenses							
	a. Depreciation	2.63%		432	438	436	436	1,740
	b. Amortization			0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008313		138	138	138	138	550
	e. Other			0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,722	2,737	2,744	2,739	10,943
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,722	2,737	2,744	2,739	10,943

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	End of Period Total
1	Investments							
	a. Expenditures/Additions			$897	$319	$0	$0	$1,217
	b. Clearings to Plant			897	319	0	0	
	c. Retirements			0	0	0	0	
	d. Other			0	0	0	0	
2	Plant-In-Service/Depreciation Base		$86,450	87,348	87,667	87,667	87,667	
3	Less: Accumulated Depreciation		(424)	(871)	(918)	(1,166)	(1,414)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$86,027	86,477	86,749	86,501	86,254	
6	Average Net Investment			86,362	86,713	86,625	86,377	
7	Return on Average Net Investment							
	a. Equity Component Grossed Up For Taxes	11.16%		803	806	806	803	$3,218
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.64%		147	147	147	147	588
8	Investment Expenses							
	a. Depreciation	3.39%		247	248	248	248	990
	b. Amortization			0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008570		63	63	63	63	253
	e. Other			0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,260	1,265	1,264	1,261	5,050
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,260	1,265	1,264	1,261	5,050

HEARING EXHIBIT - 00000749

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

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

Line	Description	Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	End of Period Total
1	Investments						
	a. Expenditures/Additions		$4,593	$825	$384	$2,371	$8,274
	b. Clearings to Plant		314,950	925	384	2,371	
	c. Retirements		0	0	0	0	
	d. Other		0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	314,950	315,875	316,259	318,630	
3	Less: Accumulated Depreciation	0	(131)	(394)	(658)	(924)	
4	CWIP - Non-Interest Bearing	319,387	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$319,387	314,819	315,481	315,601	317,707	
6	Average Net Investment		312,598	315,150	315,541	316,654	
7	Return on Average Net Investment						
	a. Equity Component Grossed Up For Taxes 11.15%		2,907	2,931	2,935	2,945	$11,717
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.06%		531	536	536	538	2,142
8	Investment Expenses						
	a. Depreciation 1.00%		131	263	264	266	924
	b. Amortization		0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.003313		218	219	219	221	877
	e. Other		0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,788	3,949	3,954	3,969	15,660
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		3,788	3,949	3,954	3,969	15,660

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	End of Period Total
1	Investments						
	a. Expenditures/Additions		$21,336	$319	$0	$0	$21,656
	b. Clearings to Plant		21,336	319	0	0	
	c. Retirements		0	0	0	0	
	d. Other		0	0	0	0	
2	Plant-in-Service/Depreciation Base	$327,928	349,264	349,583	349,583	349,583	
3	Less: Accumulated Depreciation	(1,076)	(1,841)	(2,607)	(3,374)	(4,140)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$326,852	347,423	346,976	346,210	345,444	
6	Average Net Investment		337,137	347,199	346,593	345,827	
7	Return on Average Net Investment						
	a. Equity Component Grossed Up For Taxes 11.15%		3,135	3,229	3,223	3,216	$12,804
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.06%		579	596	595	594	2,349
8	Investment Expenses						
	a. Depreciation 2.63%		765	766	766	766	3,064
	b. Amortization		0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.007544		222	222	222	222	887
	e. Other		0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,696	4,807	4,800	4,792	19,095
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,696	4,807	4,800	4,792	19,095

HEARING EXHIBIT - 00000750

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
CAIR CTs (Project 7.2 Recap)

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

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	End of Period Total
1	Investments						
	a. Expenditures/Additions		$3,590	$1,838	$276	$590	$6,894
	b. Clearings to Plant		3,580	1,838	276	880	
	c. Retirements		0	0	0	0	
	d. Other		0	0	0	0	
2	Plant-in-Service/Depreciation Base	$127,418	131,006	132,846	133,122	134,012	
3	Less: Accumulated Depreciation	(436)	(735)	(1,038)	(1,342)	(1,648)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$126,983	130,273	131,809	131,780	132,364	
6	Average Net Investment		128,628	131,041	131,794	132,072	
7	Return on Average Net Investment						
	a. Equity Component Grossed Up For Taxes 11.16%		1,196	1,219	1,226	1,228	$4,869
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		219	223	224	225	890
8	Investment Expenses						
	a. Depreciation 2.74%		299	303	304	306	1,212
	b. Amortization		0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.008974		98	99	100	100	397
	e. Other		0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,812	1,844	1,853	1,859	7,368
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,812	1,844	1,853	1,859	7,368

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

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	End of Period Total
1	Investments						
	a. Expenditures/Additions		$3,101	$1,641	$3,677	$1,200	$9,718
	b. Clearings to Plant		374,942	1,641	3,577	1,200	
	c. Retirements		0	0	0	0	
	d. Other		0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	374,942	376,483	380,360	381,560	
3	Less: Accumulated Depreciation	0	(331)	(998)	(1,666)	(2,342)	
4	CWIP - Non-Interest Bearing	371,841	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$371,841	374,611	375,487	378,691	379,217	
6	Average Net Investment		373,226	375,049	377,089	378,954	
7	Return on Average Net Investment						
	a. Equity Component Grossed Up For Taxes 11.16%		3,471	3,488	3,507	3,524	$13,990
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		634	638	641	644	2,557
8	Investment Expenses						
	a. Depreciation 2.12%		331	665	672	674	2,342
	b. Amortization		0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.008464		264	266	268	268	1,066
	e. Other		0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,701	5,058	5,088	5,111	19,958
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,701	5,058	5,088	5,111	19,958

HEARING EXHIBIT - 00000751

ECRC
Turner Tank 8
Refund Analysis

TOTAL COSTS	Dec-03	2004	2005	2006	2007	Jan-08	Feb-08	Total
Life-To-Date Cost Incurred	$ 509,360	$ 623,791	$ 623,792	$ 673,740	$ 673,740	$ 674,010	$ 674,010	$ 674,010
Return on Investment Rate (Actual/Est Filings):								
Equity Component	10.75%	10.75%	10.75%	11.16%	11.16%	11.16%	11.16%	
Debt Component	2.57%	2.57%	2.57%	2.04%	2.04%	2.04%	2.04%	
Equity Component	$ 2,282	65,243	67,058	71,591	75,191	6,268	6,268	
Debt Component	$ 545	15,598	16,031	13,086	13,745	1,146	1,146	
YTD Clause Recoverable	$ 2,827	$ 80,841	$ 83,089	$ 84,677	$ 88,935	$ 7,414	$ 7,414	$ 355,197
Commercial Paper Rate <a>	1.030%	2.280%	4.255%	5.260%	4.865%	4.030%	3.085%	
Commercial Paper Interest	$ 2	$ 1,843	$ 3,535	$ 4,454	$ 4,327	$ 25	$ 19	$ 14,206
Recoverable + Interest	$ 2,829	$ 82,684	$ 86,625	$ 89,131	$ 93,262	$ 7,439	$ 7,433	$ 369,403

IMPAIRED COSTS	2003	2004	2005	2006	2007	Jan-08	Feb-08	Total
Life-To-Date Cost Incurred	$ 298,644	$ 298,644	$ 298,644	$ 367,843	$ 367,843	$ 367,843	$ 367,843	**$ 367,843**
% of Total	58.63%	47.88%	47.88%	54.60%	54.60%	54.58%	54.58%	
Return on Investment Rate (Actual/Est Filings):								
Equity Component	$ 1,338	31,236	32,104	39,087	41,052	3,421	3,421	
Debt Component	$ 320	7,467	7,675	7,145	7,504	625	625	
Life-To-Date Cost Incurred	$ 1,657	$ 38,703	$ 39,779	$ 46,231	$ 48,556	$ 4,046	$ 4,046	**$ 183,020**
Commercial Paper Rate <a>	1.030%	2.280%	4.255%	5.260%	4.865%	4.030%	3.085%	
Commercial Paper Interest	$ 1	$ 882	$ 1,693	$ 2,432	$ 2,362	$ 14	$ 10	**$ 7,394**
Recoverable + Interest	$ 1,659	$ 39,585	$ 41,472	$ 48,663	$ 50,918	$ 4,060	$ 4,057	$ 190,414
Amt Refundable								**$ 190,414**

Proposed breakout of CWIP into Recoverable O&M Exp and Refund to Customer

CWIP Balance Impaired - (O&M)		367,843
Refund to Customer - (cr. Return on Investment)	<b>	190,414

<a> - The commercial paper rate was obtained off of Form 42-3A of the actuals filing for 2003-2007 and from Form 42-3E on the 2008 estimated filing.
<b> - Amount of return previously earned through the clause that is due back to the customer. The amount has been increased $629 from $189,785 to $190,414 due to an error in the calculation. This change will be corrected within the 2008 True-up Filing.

HEARING EXHIBIT - 00000752

ECRC
Turner Tank 8
Impairment Detail Summary

Costs directly related to Impairment	Direct Costs	Burden Costs	Total
Materials	$105,743	4,242	$109,985
Instalation Contractor Bradford	$146,422		146,422
Excelltec	$4,136		4,136
Utility Assoc	$27,767		27,767
Tank Engr and Mgmt	$10,334		10,334
Impairment - ECRC Recovered	**$294,402**	**$4,242**	**$298,644**
Add:			
PE Labor '06	$49,908	19,291	69,199
Impairment - ECRC Recovered '06-'08	**$344,310**	**$23,533**	**$367,843**

Costs not related to Impairment	Direct Costs	Burden Costs	Total
Remove Heavy oil equip and Misc	$54,000		$ 54,000
Replace seal on floating roof	$45,300		45,300
Misc testing, cleaning, grouting	$25,100		25,100
Engr for piping upgrades	$17,600		17,600
Labor and material pipe installation	$13,600		13,600
External tank coating	$53,000		53,000
Coating Materials	$13,000		13,000
Cathodic Protection	$24,000		24,000
Alarms	$2,000		2,000
Indus Fire and safety	$900		900
PE Labor	$41,590	16,076	57,666
	$290,090	$16,076	$306,166
	←	<1>	→
TOTAL COSTS INCURRED	$634,400	$39,609	$674,009

Burden Costs Detail	$ Amt
Direct Costs	634,400
Total Costs per Business Objects	674,009
Burden Costs to be Allocated	39,609
Burden Costs - Material	4,242
Burden Costs - Labor	35,367

<1> ↓

PROGRESS ENERGY FLORIDA, INC.
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2003 through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 03	Actual February 03	Actual March 03	Actual April 03	Actual May 03	Actual June 03	Actual July 03	Actual August 03	Actual September 03	Actual October 03	Actual November 03	Actual December 03	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$509,360	
	b. Clearings to Plant			0	0	0	0	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 (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	509,360	
5	Net Investment (Lines 2 - 3 + 4)		$0	0	0	0	0	0	0	0	0	0	0	0	509,360	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	254,680	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (D)	10.75%		0	0	0	0	0	0	0	0	0	0	0	2,282	$2,282
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.57%		0	0	0	0	0	0	0	0	0	0	0	545	545
8	Investment Expenses															
	a. Depreciation (E)	4.80%		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			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (J)			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	2,827	2,827
	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			0	0	0	0	0	0	0	0	0	0	0	2,827	2,827
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)			0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.7456200	0.7456200	0.7456200	
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	2,108	2,108
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,108	$2,108

Notes:
(A) Description and reason for 'Other' adjustments to net investment. None for this period.
(B) Applicable beginning of period and end of period depreciable base by plant name(s), unit(s), or plant account(s).
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Turner CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 4.80% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Amortization period is approximately 21 years for Above Ground Tank Secondary Containment - Turner CTs.
(G) Description and reason for 'Other' adjustments to investment expenses. None for this period.
(H) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(I) Line 9b x Line 11
(J) Lines 2 + 3 x .020912 x 1/12. Based on 2002 Actual Property Tax Milage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

HEARING EXHIBIT - 00000754

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2004 to December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4a)
(In Dollars)

Line	Description			Beginning of Period Amount	Actual January 04	Actual February 04	Actual March 04	Actual April 04	Actual May 04	Actual June 04	Actual July 04	Actual August 04	Actual September 04	Actual October 04	Actual November 04	Actual December 04	End of Period Total
1	Investments																
	a. Expenditures/Additions				$73,751	$8,746	$8,609	$3,556	$8,744	$8,981	$3,491	$1,965	$0	$0	$0	$532	
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (A)				0	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	0
3	Less: Accumulated Depreciation (C)			0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	CWIP - Non-Interest Bearing	9.93%		509,360	583,111	591,859	598,469	602,055	606,799	617,780	621,271	623,259	623,259	623,259	623,259	623,791	
5	Net Investment (Lines 2 - 3 + 4)	60.276		$509,360	583,111	591,859	598,469	602,055	606,799	617,780	621,271	623,259	623,259	623,259	623,259	623,791	
		606,907															
6	Average Net Investment				546,236	587,485	595,164	600,262	606,427	613,290	619,526	622,265	623,259	623,259	623,259	623,525	
7	Return on Average Net Investment																
	a. Equity Component Grossed Up For Taxes (D)		10.75%		4,893	5,263	5,332	5,377	5,424	5,494	5,550	5,574	5,583	5,583	5,583	5,586	$65,243
	b. Debt Component (Line 6 x 2.57% x 1/12)		2.57%		1,170	1,258	1,275	1,286	1,297	1,313	1,327	1,333	1,335	1,335	1,335	1,335	15,596
8	Investment Expenses																
	a. Depreciation (E)	4.80%			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 (I)				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other (F)				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				6,063	6,521	6,606	6,663	6,720	6,808	6,877	6,907	6,918	6,918	6,918	6,921	80,840
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				6,063	6,521	6,606	6,663	6,720	6,808	6,877	6,907	6,918	6,918	6,918	6,921	80,840
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)				0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	
12	Retail Energy-Related Recoverable Costs (G)				0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (H)				4,521	4,862	4,926	4,966	5,011	5,076	5,128	5,150	5,158	5,158	5,158	5,160	60,276
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$4,521	$4,862	$4,926	$4,966	$5,011	$5,076	$5,128	$5,150	$5,158	$5,158	$5,158	$5,160	$60,276

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Turner CTs project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Above Ground Tank Secondary Containment - Turner CTs.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Turner CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 8.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 4.80% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Turner CTs project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .020912 x 1/12. Based on 2002 Actual Property Tax Milage Rate.

	post-tax calc	System Amt
	6.55% equity	623,525
	2.57% debt	623,525

Source:
Line 6c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

HEARING EXHIBIT - 00000755

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2005 to December 2005

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 05	Actual February 05	Actual March 05	Actual April 05	Actual May 05	Actual June 05	Actual July 05	Actual August 05	Actual September 05	Actual October 05	Actual November 05	Actual December 05	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 (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		623,791	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	
5	Net Investment (Lines 2 - 3 + 4)		$623,791	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	
6	Average Net Investment			623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	623,792	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (D)	10.75%		5,588	5,588	5,588	5,588	5,588	5,588	5,588	5,588	5,588	5,588	5,588	5,588	$67,058
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.57%		1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	16,031
8	Investment Expenses															
	a. Depreciation (E)	4.80%		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 (I)			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	83,088
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	6,924	83,088
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)			0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	0.74562	
12	Retail Energy-Related Recoverable Costs (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (H)			5,163	5,163	5,163	5,163	5,163	5,163	5,163	5,163	5,163	5,163	5,163	5,163	61,952
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$5,163	$5,163	$5,163	$5,163	$5,163	$5,163	$5,163	$5,163	$5,163	$5,163	$5,163	$5,163	$61,952

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Turner CTs project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Above Ground Tank Secondary Containment - Turner CTs.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Turner CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 4.80% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Turner CTs project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .020912 x 1/12. Based on 2002 Actual Property Tax Milage Rate.

	post-tax calc.
6.55%	equity
2.57%	debt

Source:
Line 6c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

HEARING EXHIBIT - 00000756

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

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$4,752	$5,133	$14,486	$24,174	$1,402	$0	$0	$49,948
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		623,792	623,792	623,792	623,792	623,792	623,792	628,544	633,677	648,163	672,338	673,740	673,740	673,740	
5	Net Investment (Lines 2 + 3 + 4)		$623,792	623,792	623,792	623,792	623,792	623,792	628,544	633,677	648,163	672,338	673,740	673,740	673,740	
6	Average Net Investment			623,792	623,792	623,792	623,792	623,792	626,168	631,111	640,920	660,251	673,039	673,740	673,740	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		5,801	5,801	5,801	5,801	5,801	5,823	5,869	5,961	6,140	6,259	6,266	6,266	$71,591
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,060	1,060	1,060	1,060	1,060	1,064	1,073	1,090	1,122	1,144	1,145	1,145	13,086
8	Investment Expenses															
	a. Depreciation	1.83%		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	0.021580		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)			6,862	6,862	6,862	6,862	6,862	6,888	6,942	7,050	7,263	7,403	7,411	7,411	84,677
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$6,862	$6,862	$6,862	$6,862	$6,862	$6,888	$6,942	$7,050	$7,263	$7,403	$7,411	$7,411	$84,677

HEARING EXHIBIT - 00000757

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

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$270	$270
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	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	0	
4	CWIP - Non-Interest Bearing		673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	674,010	
5	Net Investment (Lines 2 + 3 + 4)		$673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	674,010	
6	Average Net Investment			673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,875	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,267	$75,191
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,146	13,745
8	Investment Expenses															
	a. Depreciation	1.86%		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	0.018567		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)			7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,413	88,935
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,413	88,935

HEARING EXHIBIT - 00000758

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
January 2008 through December 2008

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	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments										
	a. Expenditures/Additions			$0	$303,297	$35,483	$29,422	$327,000	$350,000	$225,000	$2,007,079
	b. Clearings to Plant			0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	
	d. Other			0	0	(367,843)	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	1,170,000	1,170,000	1,170,000	
3	Less: Accumulated Depreciation		0	0	0	0	0	(4,545)	(6,363)	(8,181)	
4	CWIP - Non-Interest Bearing		674,010	674,010	977,307	644,946	674,368	568,246	918,246	1,143,246	
5	Net Investment (Lines 2 + 3 + 4)		$674,010	674,010	977,307	644,946	674,368	1,733,701	2,081,883	2,305,065	
6	Average Net Investment			674,010	825,658	627,205	659,657	1,571,110	1,907,792	2,193,474	
7	Return on Average Net Investment										
	a. Equity Component Grossed Up For Taxes	11.16%		6,268	7,679	5,833	6,135	14,611	17,742	20,399	$125,634
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,146	1,404	1,066	1,121	2,671	3,243	3,729	22,986
	c. Other			0	0	(189,785)	0	0	0	0	(189,785)
8	Investment Expenses										
	a. Depreciation	1.86%		0	0	0	0	1,818	1,818	1,818	8,181
	b. Amortization			0	0	0	0	0	0	0	0
	c. Dismantlement			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	875	875	875	4,375
	e. Other			0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			7,414	9,083	(182,886)	7,256	19,975	23,678	26,821	(28,629)
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			7,414	9,083	(182,886)	7,256	19,975	23,678	26,821	(28,629)

HEARING EXHIBIT - 00000759

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PEF's response to Staff's First Set of Interrogatories (Nos. 1 - 4)

HEARING EXHIBIT - 00000760

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No. 080007-EI
	Dated: July 28, 2008

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-4)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's First Set of Interrogatories (Nos. 1-4):

RESPONSES

1. **Regarding the Pipeline Integrity Management Program (PIM) discussed on page 3 of the Direct Testimony of Patricia Q. West, please provide clarifications for the following:**

   a. **Lines 10 - 12 on page 3 of the testimony indicate that the PIM O&M project expenditures were $338,637 or 43.0% lower than projected. On page 6 of the 2007 Final True-up calculation in EXH WG-1, the end of period total of the O&M cost for the PIM (Project 3a) was $449,790. Please reconcile these numbers.**

   Answer:

   Actual 2007 O&M expenditures for the Pipeline Integrity Management Program (PIM) were $449,790. The variance between this total and the projection per the Estimated/Actual Filing was $338,637. Refer to PIM project 3a in Line 1 on Form 42-4A.

   b. **On page 9 of the 2007 Final True-up calculation of EXH WQ-1, PEF presented the capital investment calculation of PIM (Project 3b). Please explain or describe the difference between this PIM (Project 3b) and the PIM Project 3b described above in 1a.**

Answer:

PEF believes this question is referring to Exhibit WG-1, Page 9 of 21 and PIM Project 3a described above in 1a. Project 3a, as described in 1a, consists of the PIM O&M projects and is presented on Exhibit WG-1, Page 6 of 21. Project 3b, is presented on Exhibit WG-1, Page 9 of 21, and consists of the PIM Capital projects.

c. **Lines 14 - 20 on page 3 of the testimony explain the reasons for the delay of the PIM project. Please provide the commencing date, the original planned completion date and the current planned completion date.**

Answer:

Lines 14 – 20 refer to two projects: the Main Line Valve Guardrails project and the Main Line Valve Telemetry project.

The Telemetry project was delayed due to the need for design and installation modifications as well as the unavailability of contractors when work was scheduled. This project commenced in December 2006 and the original planned completion date was December 2007. The revised planned completion date is August 2008.

The Guardrails project was delayed to avoid conflicts with the Telemetry project and to await FDOT completion of work along a portion of the highway. This project commenced in April 2007 and the original planned completion date was December 2007. The revised planned completion date was February 2008 for the portion delayed for the Telemetry project and 2010 for the portion delayed due to FDOT work.

2. **EXH PQW-1, PEF's Clean Air Compliance Plan "D", includes "fuel switching at Crystal River Units 1 and 2 to burn low sulfur coal" as one of the measures to reduce SO2 emissions. It also includes "installation of powdered activated carbon (PAC) injection on Crystal River Unit 2" as one of the measures to reduce mercury emissions. Please explain or describe why PEF only plans to install the PAC injection on Crystal River Unit 1 rather than on both Unit 1 and 2.**

Answer:

The original Integrated Clean Air Compliance Plan (March 31, 2006) includes a review of the Clean Air Mercury Rule as it was understood at that time as well as PEF's plan to comply with the rule. As discussed in the Plan, the synergistic effects of the SCRs and scrubbers to be installed on Units 4 and 5, along with the allowances that were expected to be issued for the Crystal River coal units, only necessitated installation of a PAC injection system on Unit 2 to meet the compliance requirements of the first phase of CAMR. On page 77 (Quantitative Analysis of Alternative Compliance Plans) the Plan addresses the use of allowances and PAC injection as part of the compliance strategy: "For mercury, the allowance balance is only slightly above zero at the end of 2025. In Plan D, PAC injection systems are installed on Crystal River Unit 2 in 2017. PEF has the ability to add controls to Crystal River Unit 1 or advance the controls on Unit 2, if necessary."

These same conclusions were reached in the June 1, 2007 and April 2, 2008 Plan updates. The Integrated Clean Air Compliance Plan continues to be assessed with the evolution of federal and state rules; none of these developments has resulted in a determination to alter this aspect of the original plan. As noted in Ms. Patricia West's testimony of April 2, 2008, a recent federal appeals court decision vacated the federal CAMR regulations. This development does not immediately impact PEF's implementation of Plan D because the plan does not contemplate installation of mercury-specific controls (PAC injection) until 2017.

3. **Refer to Form 42-8A, p.13 of the Final True-up filing calculations and PEF Response to Audit Request Number: ECRC-12. Please explain or describe:**

   a. **What is the reduction amount for PEF's assertion "Line 7a and 7b included reductions to the return for this issue. (Last sentence of the response to this request)"?**

Answer: Line 7a included a reduction of $978 and Line 7b included a reduction of $179.

   b. **How are the numbers shown in line 1d (-3,767 in July, -3,040 in August, 426 in October and -1,702 in December) used in the calculation of line 9?**

Answer:

The amounts shown in line 1d are added directly to Line 9 and therefore the calculation described in Footnote E is incorrect. In future filings, any credits for return will be included in Line 7c and any credits for depreciation and property tax will be included in Line 8e.

4. **Refer to Form 42-8A, p.5 of the Final True-up filing calculations. Please explain or describe how line 1c NOx Emission Allowance was derived and how it relates to line 6b and line 7.**

Answer:

Line 1c represents the inventory of NOx Emission Allowances. It is calculated based on the cost of NOx Emissions Allowances acquired that are charged to the inventory account designated for these allowances. During each accounting close, the expenditures for the current month are added to the ending inventory balance from the prior period and the new inventory balance is verified to the general ledger account balance. The inventory of NOx allowances will be expensed beginning in 2009 as they are used for compliance purposes.

Line 1c has no impact on Lines 6b or 7. These lines account for SO2 Auction Proceeds amortization and SO2 allowance expense.

DATED this 28th day of July, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko, Esquire
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

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PEF's response to Staff's Second Set of Interrogatories (Nos. 5 - 7)

HEARING EXHIBIT - 00000766

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 080007-EI
	DATED: AUGUST 25, 2008

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 5-7)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Second Set of Interrogatories (Nos. 5-7):

RESPONSES

5. **Regarding the proposed Low Level Radioactive Waste Storage Project, please describe or explain:**

   a. **The time line of the project, using the completion of the following activities as the milestones: purchasing five storage containers, engineering analysis, additional engineering, licensing and training activities, and construction of a separate on-site storage facility;**

Answer: Two on-site storage containers (OSSC) to be purchased December 2010 and three more to be purchased December 2012; Engineering analysis for the approval to store OSSC's on the south side of CR3's security zone (referred to as the "berm") to be completed prior to April 2010; Additional engineering and environmental analysis will be required if the storage facility needs to be located off the berm due to the potential flood plan concerns. This study will be completed by June 2010; Training and licensing activities will be completed by December 2010; Construction of a separate on-site storage facility, if needed, is projected to be completed June 2011.

   b. **PEF's statement: "Any new costs that are incurred under this project will be offset by the savings that result from terminating shipments to Barnwell County";**

Answer: The Barnwell, South Carolina Low-Level Radioactive Waste Disposal Facility will no longer be available to PEF to dispose of Class B and Class C low level waste. Beginning June 30, 2008 Crystal River 3, no longer has a licensed disposal facility available to dispose of its Class B and Class C LLW. In accordance with NRC guidelines,

HEARING EXHIBIT - 00000767

the only NRC-authorized method for disposal is by transfer to a licensed low-level radioactive waste disposal facility. Until new disposal options become available, PEF will need to construct on-site storage for its Class B and Class C LLW. This interim storage will result in incremental increases in capital and O&M costs associated with the construction of facilities and the management and handling of the LLW on-site, which would not be required if the LLW could be disposed of.

Crystal River 3 will continue to accrue the costs for disposal of LLW when the LLW is first generated. This accrual process is repeated each year for all waste that has been generated during that year but has not been disposed of. Accruals are based on the projected costs to dispose of the waste at the time the accrual is assessed. Accrual of disposal costs on the LLW that Crystal River 3 must store on-site is appropriate because Crystal River 3 remains responsible for disposing of that LLW at some future date. Crystal River 3 is currently accruing disposal costs based on the existing Barnwell disposal fees. Based on the LLW disposal historical cost structure, PEF expects that the ultimate actual disposal cost will be at least as much as the accruals, as it does not appear likely at this time a future disposal facility would charge a lower fee than what was being charged to dispose LLW at Barnwell County.

c. How much, if any, PEF has spent each year for off-site LLW storage including disposal fees for the last 10 years;

Answer: PEF's Crystal has not stored LLW off-site, however disposal costs are as follows:

1999

Shipment # 99-091, 12/1/99, 8-120 Resin HIC, Approximate Cost: $85,000.00
Total 1999: $85,000.00

2000 Shipment # 00-023, 6/13/08, 8-120 Filter HIC, Cost: Approximately $52,000.00
Total 2000: $52,000.00

2001 Shipment #01-027, 6/1/01, 8-120 Filter HIC, Cost: $41,479.54
Total 2001: $41,479.54

2002

Shipment 02-014, 3/21/02, 8-120 Filter HIC, Cost: $54,459.74
Shipment 02-022, 5/9/02, 8-120 Resin HIC, Cost: $111,741.84
Shipment 02-026, 5/30/02, 8-120 Resin HIC, Cost: $114,905.24
Total 2002: $281,106.82

2003 Shipment 03-046, 8/26/03, 8-120 Filter HIC, Cost: $42,402.80
Shipment 03-093, 12/11/03, 8-120 Resin HIC, Cost: $128,743.00
Total 2003: $171,145.80

2004 No Shipments to Barnwell or processed through Studsvik Processing Facility

2005 Shipment 05-034, 7/29/05, 8-120 Resin HIC, Cost: $38,914.00
Shipment 05-035, 8/5/05, 8-120 Resin HIC, Cost: $156,379.00
Shipment 05-036, 8/11/05, 8-120 Resin HIC, Cost: $161,823.00
Shipment 05-040, 8/31/05, 8-120 Resin HIC, Cost: $141,104.00
Shipment 05-045, 9/22/05, 8-120 Filter HIC, Cost: $150,195.00
Total 2005: $648,415.00

2006 No Shipments to Barnwell or processed through Studsvik Processing Facility

2007 Shipment 07-019, 4/18/07, 8-120 Resin HIC, Cost: $151,846.00
Shipment 07-021, 4/25/07, 8-120 Resin HIC, Cost: $150,856.00
Shipment 07-023, 5/9/07, 8-120 Resin HIC, Cost: $150,856.00
Shipment 07-026, 5/16/07, 8-120 Resin HIC, Cost: $150,842.00
Total 2007: $604,400.00

2008 Shipment 08-020, 3/18/08, 8-120 Filter HIC, Cost: $177,926.00
Shipment 08-025, 4/2/08, 8-120 Resin HIC, Approximate Cost: $167,000.00
Shipment 08-028, 4/16/08, 8-120 Resin HIC, Approximate Cost: $167,000.00.
Shipment 08-030, 4/30/08, 8-120 Resin HIC, Approximate Cost: $167,000.00.
Shipment 08-031, 5/7/08, 8-120 Resin, Approximate Cost: $167,000.00
Total 2008: $845,926.00

d. How much of the expenditure described in interrogatory No. 5c was recovered through the base rate each year;

Answer: Approximately $600,000 of disposal costs were recovered through base rates each year. No costs described in No. 5c were recovered through the Environmental Cost Recovery Clause during these years.

e. What is the Useful life (years) of the storage containers that will be purchased initially;

Answer: The useful life is expected to be for the life of the plant. With the approval of the license extension, Crystal River -3 has an expected life through 2037.

f. What is the Useful life (years) of the separate on-site storage facility that PEF may construct commencing in late 2009.

Answer: The useful life will be for the "life" of the plant.

g. **What will be the O&M costs for the on-site storage facility?**

Answer: When the facility is operating there will be routine operating costs incurred to operate and maintain the facility. Such costs will include but not limited to resources to survey and monitor the facility, escort LLW to the facility, and transportation/hauling equipment rental and repairs. Minor repairs and periodic painting and other maintenance may also be required. Total O&M costs are expected to be between $20,000 - $40,000/year.

6. **Regarding the proposed Greenhouse gas Inventory and reporting project, please describe or explain, in detail, the scope of PEF's Greenhouse Gas (GHG) Reduction Program;**

Answer: Progress Energy Florida is currently developing an entity-wide greenhouse gas inventory; a reduction program has not been initiated. The greenhouse inventory will align with The Climate Registry General Reporting protocol and other nationally-recognized protocols, establish a baseline for the company, and be of a quality and format for successful independent verification and external reporting.

A detailed analysis of greenhouse gas emissions is being conducted for all six major greenhouse gases (CO_2, CH_4, N_2O, PFCs, HFCs, and SF6) and will include direct and indirect emissions from each of the following owned or controlled functional areas of the organization:

- Stationary sources (e.g., boilers, turbines, internal combustion engines)
- Electricity transmission and distribution (e.g., transmission and distribution losses from purchased or wheeled electricity)
- Fugitive sources (e.g., air conditioning, fire suppression equipment, SF6)
- Mobile sources (e.g., road, air, rail)
- Process sources (e.g., sorbent use for flue gas desulfurization systems)
- Facilities (e.g., office buildings)

Source of Scope 3 emissions (as defined in the WBCSD/WRI GHG protocol and The Climate Registry protocol – such as employee commuting and transportation of waste materials) will be identified, but not quantified in this scope of work.

Development of the greenhouse gas inventory includes the following distinct tasks:

Task 1. Develop Greenhouse Gas Inventory Plan. The Greenhouse Gas Inventory Plan will define the scope of work, roles and responsibilities, project timeline, resource needs for data collection and deliverables. It will also capture key decisions that will be required early in the project, such as operational boundaries; identification of sources that will be included and excluded in the inventory; and emissions calculation methodologies.

Task 2. Collect Data. Identified field resources will develop comprehensive list of greenhouse gas emissions sources and will collect operational data required to support the emissions calculations.

Task 3. Calculate Greenhouse Gas Emissions. Greenhouse gas emissions will be calculated and documented on an Excel spreadsheet as determined in the Greenhouse Gas Inventory Plan. Once the inventory has been generated, potential de minimis sources will be identified and a baseline will be established. For each source, the spreadsheet will indicate the quality of the calculation or estimation methodology used and an explanation of why this approach was chosen. Emissions will be entered into The Climate Registry reporting software, CRIS.

Task 4. Establish Ongoing Implementation Strategy. The Greenhouse Gas Inventory Core Team will develop the ongoing strategy for collecting, calculating and documenting the annual greenhouse emissions inventory. The recommended strategy will be documented for internal management review.

Progress Energy is a founding reporter to the Climate Registry, which will require reporting of annual emissions by June 30 of each year and third-party verification by December 15 of each year. The first reporting to the Registry will occur by June 30, 2009 for 2008 emissions.

7. **Regarding the proposed Crystal River Thermal Discharge Compliance Project,**

a. **Please explain the differences between the three kinds of cooling towers: Modular Cooling Tower; 12 Cell Circular Cooling Tower; and Helper Cooling Tower.**

Answer: The discharge canal is equipped with two groupings of once-through cooling towers. The first group, Helper Cooling Towers (HCTs), is a permanent arrangement of four linear forced draft cooling towers termed 'Helper Towers.' These towers are designated HCT-1, HCT-2, HCT-3, and HCT-4. This set of towers was designed by Hamon Cooling Towers and entered service in 1991. Each HCT consists of nine cells. Each cell is rated at 19,000 gpm, resulting in each HCT operating at ~ 171,000 gpm, for a total capacity of ~ 684,000 gpm. The HCTs are served by a set of four seawater lift pumps. The discharge of the lift pumps is to a common header which can be valved to direct flow from the pumps to the various towers. The combined capacity of the thirty-six (36) cells, which make up the four Hamon towers, is currently ~52% of the total (summer) flow in the canal. The total discharge canal flow during the summer is ~ 1,318,680 gpm.

The Modular Cooling Towers (MCTs), the second group, are mechanical forced draft cooling towers. The four groupings of modular towers were installed and first operated

in the summer of 2006. The MCTs are comprised of a total of sixty-seven (67) smaller units. The MCTs are temporary units that were leased from Aggreko for five years, were installed by Aggreko, and are owned and maintained by Aggreko. The Aggreko lease started in 2006 and runs through the summer of 2010. Flow through the modular cooling towers is estimated at 180,000 gpm or ~14% of total flow in the discharge canal. The Commission approved recovery of prudently incurred costs for the MCTs in Docket No. 060162-EI.

The proposed 12 Cell Circular Cooling Tower is a set of 12 cooling cells (similar to the HCTs) arranged in a circular pattern. The circular arrangement makes the cooling tower more efficient than those arranged in a line configuration. The flow through the proposed cooling tower will be approximately 240,000 gpm. Specifics of this cooling tower's design have not been completed.

b. Please provide the total Revenue Requirements for the proposed permanent cooling solution over 15 years.

Answer: Please see Attachment 7-1 for the estimated revenue requirements. These estimates are preliminary estimates based on studies that are still in progress. The final thermal discharge compliance solution has not yet been determined and no contracts have been issued for the construction of the new equipment. As such, the final revenue requirements may vary significantly. Also, the preliminary estimates in Attachment 7-1 are based on an estimated cost allocation between drivers (CR3 Uprate vs. CR1&2 Environmental) using the respective heat mitigation for each as an allocation basis.

c. Please state the annual costs PEF currently incurs for leasing the Modular Cooling Towers.

Answer: The annual lease payment is $3,336,752 based on $834,188 per month for the months of June, July, August and September. Additional costs consist of approximately $1.6 million for installation and approximately $0.9 million for removal. The total 5 year cost is expected to be approximately $19.3 million.

d. Please provide a side by side comparison of the Revenue Requirements for Crystal River Unit 1 & Unit 2 (CR1 & CR2) with and without the permanent cooling water solution. Please also describe or explain all the assumptions used.

Answer: PEF interprets this interrogatory to be asking for the relevant changes in revenue requirements associated with Crystal River Units 1 & 2 with and without the permanent POD solution. For these purposes a scenario without the permanent solution will be considered the base case and changes associated with having a permanent solution will be considered. The relevant cost changes are primarily associated with changes due to additional capital investment and changes in fuel costs. Please see the response to

question 7b above for preliminary capital cost estimates over the first 15 years of operation. With regard to estimating the fuel savings, this is heavily dependent on environmental conditions and fuel prices. Assuming a replacement fuel cost of between $90 and $130 per MWh and using PEF's experience from 2003-2007 to calculate an average annual avoided 110,760 MWh's per year, PEF estimates the average annual savings due to avoided derates would be between $10 and $15 million per year. By comparison, the preliminary estimated annual revenue requirements for the first 15 years range from approximately $6.2 to $10.6 million per year, as shown on Attachment 7-1.

e. **Please provide the Useful life (years) of the proposed permanent cooling solution facility.**

Answer: The useful life (years) of the proposed permanent cooling solution facility is 30 years.

f. **Please provide the useful life remaining (years from 2009 to the retirement) of CR1 and CR2.**

Answer: At this time, PEF does not have a planned retirement date for Crystal River Units 1 & 2.

DATED this 26th day of August, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____
Gary V. Perko
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

Estimated Revenue Requirements of Permanent POD Solution

Response to Staff's 2nd Set of Interrogatories No. 7b

Attachment 7-1
Docket 080007

Inputs

Insurance Rate	0.09%
Property Tax Rate	1.13%
WACC Rate	13.20%
Book Value of Asset	61,770,000
Depreciation Rate (1)	3.06%
In-Service Date	6/1/2011

	2011 Projected	2012 Projected	2013 Projected	2014 Projected	2015 Projected	2016 Projected	2017 Projected	2018 Projected	2019 Projected	2020 Projected	2021 Projected	2022 Projected	2023 Projected	2024 Projected	2025 Projected
Gross Book Value	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000	61,770,000
Book Depreciation	1,707,595	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162
Net Book Value	61,062,405	59,872,243	59,867,082	59,986,920	59,106,758	57,216,596	55,326,434	53,436,272	51,546,110	49,655,948	47,765,786	45,875,624	43,985,462	42,095,300	40,205,138
Return on Investment	4,707,855	7,660,361	7,630,954	7,381,547	7,132,140	6,882,733	6,633,326	6,383,919	6,134,513	5,885,106	5,635,699	5,386,292	5,136,885	4,887,478	4,638,071
Depreciation	1,707,595	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162	1,890,162
Property Insurance	55,593	55,593	55,593	55,593	55,593	55,593	55,593	55,593	55,593	55,593	55,593	55,593	55,593	55,593	55,593
Property Taxes	697,767	698,001	698,001	698,001	698,001	698,001	698,001	698,001	698,001	698,001	698,001	698,001	698,001	698,001	698,001
O&M (2)	185,434	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Total Revenue Regs	8,454,244	10,574,117	10,524,710	10,275,303	10,025,896	9,776,489	9,527,082	9,277,675	9,028,269	8,778,862	8,529,455	8,280,048	8,030,641	7,781,234	7,531,827

Note

(1) Depreciation rate comes from Order No. PSC-05-0945-S-EI on Docket 050078 page 159 of Attachment A.

(2) O&M assumption based on current O&M costs of the current Helper Cooling Towers which have a heat rejection capacity of 4.57 B BTUs/Hr. The O&M maintenance budget is approximately 500,000 dollars per year. The new equipment solution heat rejection capacity is 2.29 B BTUs/Hr. The expected O&M maintenance cost is estimated to be 250,000 dollars per year (half of the Helper Cooling Towers O&M maintenance budget) for the new equipment. The electrical auxiliary power requirements are being evaluated. These are preliminary estimates and will be refined during the design phase of the project.

HEARING EXHIBIT - 00000774

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF CITRUS)

Before me, the undersigned authority, personally appeared July 30, 2008, who

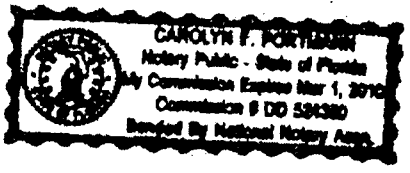
(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 5 of Staff's 2nd Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 080007-EI are true and correct to the best of his knowledge, information and belief.

Mark D. Rigsby
Superintendent Radiation Protection

Notary Public
State of Florida

My commission Expires:



AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared Patricia Q. West, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory No. 6 of Staff's 2nd Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 080007-EI are true and correct to the best of his knowledge, information and belief.

Patricia Q. West

Patricia Q. West

Manager, Environmental Svcs.

Title

June C. Mooney

Notary Public
State of Florida

My commission Expires: September 18, 2012

JUNE C. MOONEY
MY COMMISSION # DD806913
EXPIRES: September 18, 2012
FL Notary Discount Assoc Co

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared Daniel L. Roderick, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 7a, c, d, e and f of Staff's 2nd Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 080007-EI are true and correct to the best of his knowledge, information and belief.

Daniel L. Roderick

VP Nuclear Project & Construction
Title

Helen M. Kyriakou
Notary Public
State of Florida

Helen M. Kyriakou
Commission # DD455582
Expires October 24, 2009
Bonded Troy Fain - Insurance, Inc. 800-385-7019

My commission Expires: 10-24-2009

HEARING EXHIBIT - 00000777

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared Lori Cross, who

(✓) is personally known to me, or

( ) produced _____ as identification and who,

being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 7b and d of Staff's 2nd Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 080007-EI are true and correct to the best of his knowledge, information and belief.

Lori Q. Cross
Lori Cross

Mgr. Regulatory Planning & Strategy
Title

SUZANNE H. MILLER
MY COMMISSION # DD 411455
EXPIRES: March 27, 2009
Bonded Thru Notary Public Underwriters

Suzanne H. Miller
Notary Public
State of Florida

My commission Expires:
3/27/209

22

PEF's response to Staff's Third Set of Interrogatories (No. 8)

HEARING EXHIBIT - 00000779

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 080007-EI
	DATED: September 23, 2008

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES (NO. 8)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Third Set of Interrogatories (No. 8):

RESPONSES

8. **Regarding the $368,303 higher O&M cost due to the provider's failure to deliver the correct secondary containment technology described on pages 3-4 of witness P. West's testimony dated 08/04/2008, has Progress pursued any compensation from the vendor regarding the loss incurred?**

Answer: Yes. PEF has pursued compensation from the vendor for over four years. As summarized in PEF's response to Staff's Production of Document Request No. 6, "schedules relating to page 2," costs were initially incurred in 2003 and 2004, which corresponded to the scheduled time for the secondary containment upgrade at the Turner location. Once installed, the containment system never passed the acceptance testing. After contacting the vendor for corrective actions, and not receiving satisfactory remediation, PEF suspended the fieldwork. PEF subsequently hired outside counsel to communicate with the vendor in attempt to obtain recourse, either by warranty-type work or receipt of monetary refund. Additionally, during this time, PEF learned that the vendor was experiencing financial difficulty. In early 2006, the project was reopened as the vendor came under a different management team and a new attempt to "settle" the problem of the containment system was initiated. PEF's outside legal counsel provided a draft settlement agreement, but it was never executed by the vendor. However, the vendor did provide PEF with replacement putty and coatings products and a cash payment which was applied towards installation. At this time, PEF made the decision to replace the bottom and complete the project prior to the FAC imposed deadline of December 31, 2009 as it was not economically feasible to continue pursuing the vendor as the vendor could not provide satisfactory remediation and did not have the financial solvency to equitably settle the situation.

HEARING EXHIBIT - 00000780

DATED this 23rd day of September, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____

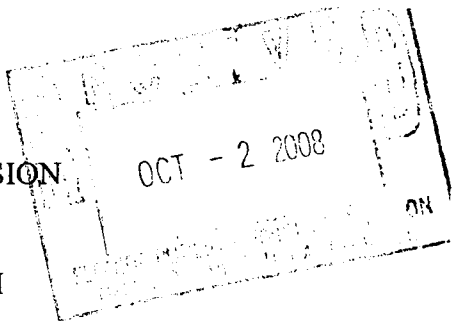
Gary V. Perko
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

23

PEF's response to Staff's Fourth Set of Interrogatories (Nos. 9 - 18)

HEARING EXHIBIT - 00000782



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 080007-EI
	DATED: October 2, 2008

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 9-18)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Fourth Set of Interrogatories (Nos. 9-18):

RESPONSES

9. **For Project 4.1-Above Ground Tank Secondary Containment-Peaking, on page 10 of 21 of Exhibit WG-1, the company provided the actual depreciation expense for the month of April 2007 in the amount of $22,824. The Capital Program Detail, Exhibit WG-2, on pages 1 through 6 of 13 provides a breakdown of the $22,824 depreciation expense by plant site as follows: $424 for Project 4.1b-Bartow CTs, $20,520 for Project 4.1c-Intercession City CTs, $520 for Project 4.1d-Avon Park CTs, $565 for Project 4.1e-Bayboro CTs, and $794 for Project 4.1h-University of Florida. Project 4.1c-Intercession City CTs' depreciation expense for April is more than the monthly calculated amount. Provide a detailed explanation of what occurred at this site and the components used in the calculation. Also, if this is a correction, please provide the appropriate breakdown for each affected month and year.**

Answer: In March 2007, the Above Ground Secondary Containment asset at Intercession City was placed in-service retroactively as of November 2006 in the plant accounting system. The depreciation expense that was not recorded from November 2006 through February 2007 ($15,960) was added to the April depreciation expense ($4,560) in the April 2007 column, line 8a. The depreciation was corrected in March in line 3 but not in line 8a due to oversight. Please see Attachments 1 and 2 for the schedules which were used for purposes of calculating the adjustment for 2006 and 2007.

10. **For Project 4.3-Above Ground Tank Secondary Containment-Intermediate, on page 12 of 21 of Exhibit WG-1 the company's monthly depreciation expense for September through December 2007 is more than twice the monthly calculated amount based upon the plant investment and Commission approved depreciation rate. Provide a detailed explanation of how the company calculated the monthly depreciation expense.**

Answer: The formula for the depreciation expense was utilizing the rate from project 4.1h instead of the rate for project 4.3 resulting in an overstatement of depreciation and property tax expense. This issue was recognized in July 2008 and therefore the depreciation expense was reduced and corrected in the July 2008 column for September 2007 through June 2008 (-$7,721) in Exhibit LC-1, line 8e, along with the correction to the property tax expense (-$1,661) for the same formula issue. See Attachment 3 for a summary of the adjustment calculation and Attachments 4 and 5 for the schedules which were used for purposes of calculating the adjustment.

11. **For Project 10.1-Underground Storage Tanks-Base, page 19 of 21 of Exhibit WG-1, shows that July 2007 was the first month the plant was placed in service, but the calculated monthly depreciation expense is more than the subsequent months. Please provide a detailed explanation of how the expense was calculated.**

Answer: In July 2007, the Underground Storage Tanks – Base project was placed in-service retroactively as of June 2007 in the plant accounting system. Depreciation expense utilizes the half-month convention for the first month an asset is in-service. Therefore, half of the monthly depreciation expense ($230) for June was added to the depreciation expense for July ($460) in the July column, line 8a. See Project 10a on Attachment 6 for the schedule used for purposes of calculating the adjustment.

12. **For Project 10.2-Underground Storage Tanks-Intermediate, page 20 of 21 of Exhibit WG-1 shows that June 2007 is the first month plant was placed in service, but the calculated monthly depreciation expense is more than five times the amount for any of the subsequent months. Please provide a detailed explanation of what occurred in the calculation of the depreciation expense.**

Answer: In June 2007, the Underground Storage Tanks – Intermediate project was placed in-service retroactively as of January 2007 in the plant accounting system.

Depreciation expense utilizes the half-month convention for the first month an asset is in-service. The depreciation expense for January through May ($909) was added to the depreciation expense for June ($202) in the June column, line 8a. See Project 10b on Attachment 7 for the schedule used for purposes of calculating the adjustment.

13. **For Project 11-Modular Cooling Towers-Base, on page 21 of 21 of Exhibit WG-1, the company shows for July 2007 an abnormal depreciation expense occurred in the amount of $19,698. Please provide a detailed explanation of how the depreciation expense was calculated. Also, if this is a depreciation true-up amount, please provide the months effected and the correct expense.**

Answer: In July 2007, additional assets for the Modular Cooling Towers – Base project totaling $147,916 were placed in-service retroactively as of March 2007 in the plant accounting system. Depreciation expense utilizes the half-month convention for the first month an asset is in-service. The depreciation expense for the new assets for March through June ($8,629) was added to the depreciation expense for July ($11,069) in the July column, line 8a. See Attachment 8 for the schedule used for purposes of calculating the adjustment.

14. **For Project 11-Modular Cooling Towers-Base, on page 21 of 21 of Exhibit WG-1, line 1(d) Other(A), the company explained in "Note (A) that a credit was applied reflecting expenses recovered through base rates for the breakers that were replaced to compensate for the increased load." It is not apparent to staff to what account(s) the credits were applied for the months of July, August, October, and December 2007. If the credits should not be included in any of the plant totals, please explain why.**

Answer: These credits were for return on equity and debt, depreciation, and property taxes recovered in base rates for the original breakers that were replaced by the breakers placed in-service in March 2007 as ECRC assets. Therefore, they were applied directly to Line 9 because they are not capital expenditure credits that would affect line 2. In the future, any adjustments for return will be included in line 7c and any adjustments for depreciation and property tax will be included in line 8e.

15. **For Project 3.1, on page 9 of 22, line 8(a), the company shows a change in the depreciation expense for the period of January through April and May through**

December, in the amount of $6,843 and $9,109. Also, reflected on line 8(e)-Other(g), the company provided a depreciation true-up in the amount of $63,462.

a. **Provide a detailed explanation of why the company used different depreciation rates and resulting expenses as stated above for the period of January through April and May through December.**
b. **Provide a month to month breakdown of the $63,462 depreciation true-up as shown on line 8(e) Other (g).**

Answer: Please see response to No. 6 of Staff's Fourth Request for Production Documents as related to Page 1.

16. **The overall summary for Project 4.1-Above Ground Tank Secondary Containment-Peaking, the depreciation expense on line 3- Less: Accumulated Depreciation, for the month of March 2008 includes an additional $6,840 in depreciation expense. Staff review of the company's Capital Program Detail, Exhibit LC-2 attributes this excess depreciation expense to Project 4.1(c)-Intercession City CTs. Explain in detail why the excess depreciation expense in the amount of $6,840 was included in the March total, although the monthly depreciation expense for Intercession City CTs is only $4,694.**

Answer: The additional $6,840 in depreciation expense was included in March 2008 due to oversight as it was actually an adjustment included for March 2007 that was not deleted from the cell. The issue was corrected in line 3 in July 2008.

17. **For Project 4.3, on line 8e-Other(G), the company shows $9,382 as a depreciation true-up amount which is also stated in the Note section.**

a. **Please provide the appropriate depreciation rate and depreciation expense by the applicable months which determined the depreciation true-up in the amount of $9,382.**
b. **Please explain in detail why the company did not include the depreciation expense true-up as part of line 3-Less: Accumulated Depreciation.**

Answer: Please see response to Interrogatory No. 10 above. The amount included in line 3 was $7,721 per the information in that response.

18. For the project sites listed below as part of Project 7.2, the Capital Program Detail Support shows a negative $10,086 in depreciation expenses occurring during May 2008. The overall summary for Project 7.2 project plant sites shows a negative depreciation expense in the amount of $9,110. Provide a detailed explanation to include why this difference occurred, the months affected, and the methodology used to calculate the May 2008 depreciation expense.

Project Number	Description	Depreciation Expense
7.2a	CAIR CTs-Avon Park	($ 184)
7.2b	CAIR CTS-Bartow	($ 440)
7.2c	CAIR CTs-Bayboro	($ 69)
7.2d	CAIR CTs-DeBary	($ 419)
7.2e	CAIR CTs-Higgins	($2,395)
7.2f	CAIR CTs-Intercession City	($3,909)
7.2g	CAIR CTs-Turner	($ 946)
7.2h	CAIR CTs-Suwannee	($1,724)
	Total	($10,086)

Answer: In the chart above, Project 7.2c and 7.2d depreciation expense was actually filed as $69 and $419 (not -$69 and -$419) which would change the total in the chart to $9,110. Please see response to No. 6 of Staff's Fourth Request for Production Documents as related to Page 7 for an explanation of this issue.

DATED this 1st day of October, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared WILL GARRETT, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 9 through No. 18 of Staff's 4th Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 080007-EI are true and correct to the best of his knowledge, information and belief.

Will Garrett

PEF Controller
Title

SUZANNE H. MILLER
MY COMMISSION # DD 411455
EXPIRES: March 27, 2009
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida

My commission Expires:
3/27/2009

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4c)

(In Dollars)

Base

20035307

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	
	c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other		-	-	-	-	-	-	-	-	-	-	-	-	
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	(3,216)	(3,327)	(3,438)	(3,549)	(3,660)	(3,772)	(3,883)	(3,994)	(4,105)	(4,216)	(4,327)	(4,438)	(4,549)	
4	CWIP - Non-Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Net Investment (Lines 2 + 3 + 4)	29,876	29,765	29,654	29,543	29,432	29,320	29,209	29,098	28,987	28,876	28,765	28,654	28,543	
6	Average Net Investment		29,821	29,709	29,598	29,487	29,376	29,265	29,154	29,043	28,931	28,820	28,709	28,598	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		277	276	276	274	273	272	271	270	269	268	267	266	3,249
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		61	61	60	60	60	60	60	48	48	48	48	48	896
8	Investment Expenses														
	a. Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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 0.016338		45	45	45	45	45	45	45	45	45	45	45	46	541
	e. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)		494	493	492	491	479	478	477	476	474	473	472	471	5,730
	a. Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand		494	493	492	491	479	478	477	476	474	473	472	471	5,730

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4d)

(In Dollars)

Peaking

20048123

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		-	-	89,493	172,938	55,368	104,160	27,054	18,527	-	28,984	220,000	-	766,521
	b. Clearings to Plant		-	-	-	-	-	-	-	-	-	-	1,814,230	-	
	c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other		-	-	-	-	-	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base	-	-	-	-	-	-	-	-	-	-	-	1,814,230	1,814,230	
3	Less: Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	(2,280)	(6,840)	
4	CWIP - Non-Interest Bearing	905,709	905,709	905,709	989,202	1,162,138	1,217,506	1,321,666	1,348,720	1,367,247	1,367,247	1,394,230	0	0	
5	Net Investment (Lines 2 + 3 + 4)	905,709	905,709	905,709	989,202	1,162,138	1,217,506	1,321,666	1,348,720	1,367,247	1,367,247	1,394,230	1,811,950	1,807,390	
6	Average Net Investment		905,709	905,709	947,455	1,075,670	1,189,822	1,269,586	1,335,193	1,357,983	1,367,247	1,380,738	1,603,090	1,809,670	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		8,423	8,423	8,811	10,004	11,066	11,807	12,417	12,629	12,715	12,841	13,979	14,870	138,085
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		1,540	1,540	1,611	1,829	2,023	2,158	2,270	2,309	2,324	2,347	2,555	2,736	25,241
8	Investment Expenses														
	a. Depreciation 3.39%		-	-	-	-	-	-	-	-	-	-	2,280	4,560	6,840
	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 0.008166		-	-	-	-	-	-	-	-	-	-	1,098	1,098	2,196
	e. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)		9,963	9,963	10,422	11,832	13,088	13,965	14,687	14,938	15,040	15,188	19,912	23,264	172,362
	a. Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand		9,963	9,963	10,422	11,832	13,088	13,965	14,687	14,938	15,040	15,188	19,912	23,264	172,362

HEARING EXHIBIT - 00000789

Docket 080007-EI
PEF's Responses to Staff's Fourth
Set of Interrogatories (Nos. 9-18)
Attachment 1

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2008 through December 2008
Above Ground Tank Secondary Containment (Projects 4.1 and 4.3 Retail)

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

Base
20035307

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	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	(4,648)	(4,861)	(4,772)	(4,883)	(4,994)	(5,105)	(5,216)	(5,327)	(5,438)	(5,550)	(5,661)	(5,772)	(5,883)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$28,443	28,231	28,320	28,209	28,098	27,987	27,876	27,765	27,653	27,542	27,431	27,320	27,209	
6	Average Net Investment		28,487	28,276	28,265	28,154	28,042	27,931	27,820	27,709	27,598	27,487	27,376	27,264	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		265	264	263	262	261	260	259	258	257	256	255	254	$3,111
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		48	48	48	48	48	47	47	47	47	47	47	46	569
8	Investment Expenses														
	a. Depreciation 4.83%		111	111	111	111	111	111	111	111	111	111	111	111	1,334
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.818338		61	46	46	46	46	46	46	46	46	46	46	46	557
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		486	486	467	466	466	463	462	461	460	459	457	456	5,570
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		486	486	467	466	466	463	462	461	460	459	457	456	5,570

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

Pasiong
20048123

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	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	$1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	1,814,230	
3	Less: Accumulated Depreciation	(9,846)	(11,490)	(13,090)	(20,521)	(26,081)	(29,641)	(34,201)	(38,761)	(43,322)	(47,882)	(52,442)	(57,002)	(61,562)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$1,804,384	1,802,740	1,801,140	1,793,710	1,788,149	1,784,589	1,780,029	1,775,469	1,770,909	1,766,348	1,761,788	1,757,228	1,752,668	
6	Average Net Investment		1,805,110	1,801,550	1,797,990	1,791,429	1,786,869	1,782,309	1,777,749	1,773,189	1,768,628	1,764,068	1,759,508	1,754,948	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		22,434	14,985	14,843	14,800	14,758	14,715	14,673	14,631	14,588	14,546	14,503	14,461	$183,837
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		4,101	2,721	2,713	2,705	2,698	2,690	2,682	2,674	2,667	2,659	2,651	2,643	33,905
8	Investment Expenses														
	a. Depreciation 3.39%		4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	54,722
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.908160		1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	13,172
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		32,192	23,264	23,214	23,164	23,113	23,063	23,013	22,963	22,913	22,863	22,812	22,762	285,336
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		32,192	23,264	23,214	23,164	23,113	23,063	23,013	22,963	22,913	22,863	22,812	22,762	285,336

HEARING EXHIBIT - 00000790

Docket 080007-EI
PEF's Responses to Staff's Fourth
Set of Interrogatories (Nos. 9-18)
Attachment 2

Anclote AST True Up For Depreciation & Prop Tax Rate Correction
Progress Energy Florida

Return on Equity

Year	Corrected Amount	Booked Amount	True Up Needed	
2007	10,542	10,498	44	
2008	15,750	15,613	137	
		Total July 2008 True Up	181	Line 7c

Return on Debt

Year	Corrected Amount	Booked Amount	True Up Needed	
2007	1,927	1,919	8	
2008	2,879	2,854	25	
		Total July 2008 True Up	33	Line 7c

Depreciation

Year	Corrected Amount	Booked Amount	True Up Needed	
2007	2,826	5,609	(2,783)	
2008	4,848	9,786	(4,938)	
		Total July 2008 True Up	(7,721)	Line 8e

Property Tax

Year	Corrected Amount	Booked Amount	True Up Needed	
2007	714	1,355	(641)	
2008	1,062	2,082	(1,020)	
		Total July 2008 True Up	(1,661)	Line 8e

HEARING EXHIBIT - 00000791

Docket 080007-EI
PEF's Responses to Staff's Fourth
Set of Interrogatories (Nos. 9-18)
Attachment 3

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail/Support - January 2008 through December 2008
Above Ground Tank Secondary Containment (Projects 4.3 and 4.3 Recap)

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

Pasting [redacted]
20080076

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	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	(8,884)	(9,592)	(10,300)	(11,121)	(11,916)	(12,710)	(13,504)	(14,298)	(15,093)	(15,887)	(16,682)	(17,476)	(18,270)	
4	CWIP - Non-Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$132,771	131,903	131,135	130,314	129,520	128,726	127,931	127,138	126,342	125,548	124,753	123,959	123,164	
6	Average Net Investment		132,337	131,509	130,711	129,917	129,122	128,328	127,534	126,739	125,945	125,150	124,356	123,562	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,145	1,223	1,216	1,208	1,201	1,193	1,186	1,179	1,171	1,164	1,157	1,149	$14,191
	b. Debt Component (Line 6 x 2.67% x 1/12) 2.04%		209	224	222	221	220	218	217	215	214	213	211	210	2,594
8	Investment Expenses														
	a. Depreciation 6.74%		668	794	794	794	794	794	794	794	794	794	794	794	9,597
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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		(340)	169	169	169	169	169	169	169	169	169	169	169	1,019
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,682	2,410	2,401	2,392	2,384	2,375	2,366	2,358	2,349	2,340	2,331	2,323	28,011
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,682	2,410	2,401	2,392	2,384	2,375	2,366	2,358	2,349	2,340	2,331	2,323	28,011

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

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$189,743	$33,541	$86,766	$247	$0	$290,297
	b. Clearings to Plant		0	0	0	0	0	0	0	0	223,284	66,766	0	247	
	c. Retirements		0	0	0	0	0	0	0	0	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	223,284	290,050	290,050	290,297	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(311)	(1,211)	(2,016)	(2,826)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	189,743	0	0	247	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	189,743	222,973	288,839	288,279	287,471	
6	Average Net Investment		0	0	0	0	0	0	0	94,871	206,358	255,906	288,559	287,875	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	0	882	1,919	2,380	2,684	2,677	$10,542
	b. Debt Component (Line 6 x 2.67% x 1/12) 2.04%		0	0	0	0	0	0	0	161	351	435	491	489	1,927
8	Investment Expenses														
	a. Depreciation 3.34%		0	0	0	0	0	0	0	0	311	900	807	806	2,826
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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		0	0	0	0	0	0	0	0	126	225	179	177	714
	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	1,044	2,716	3,940	4,158	4,151	16,009
	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		0	0	0	0	0	0	0	1,044	2,716	3,940	4,158	4,151	16,009

HEARING EXHIBIT - 00000792

Docket 080007-EI
PEF's Responses to Staff's Fourth
Set of Interrogatories (Nos. 9-18)
Attachment 4

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

Posting [redacted]

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	(18,279)	(19,064)	(19,868)	(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)	$123,156	122,370	121,575	120,782	119,988	119,194	118,400	117,606	116,813	116,018	115,224	114,430	113,636	
6	Average Net Investment		122,787	121,973	121,178	120,386	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) 2.84%		209	207	206	206	203	202	201	199	198	197	195	194	2,619
8	Investment Expenses														
	a. Depreciation 6.74%		784	784	784	784	784	784	784	784	784	784	784	784	9,529
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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	2,286	2,288	2,278	2,270	2,261	2,252	2,244	2,235	2,228	2,218	27,190
	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		2,314	2,304	2,286	2,288	2,278	2,270	2,261	2,252	2,244	2,235	2,228	2,218	27,190

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
	b. Clearings to Plant		0	0	0	0	0	0							
	c. Retirements		0	0	0	0	0	0							
	d. Other		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							
3	Less: Accumulated Depreciation	(36,609)	(6,417)	(7,225)	(8,033)	(8,841)	(9,649)	(10,457)							
4	CWIP - Non-Interest Bearing	$0	0	0	0	0	0	0							
5	Net Investment (Lines 2 + 3 + 4)	$284,689	283,881	283,073	282,265	281,457	280,649	279,841							
6	Average Net Investment		284,285	283,477	282,669	281,861	281,053	280,245							
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		2,644	2,636	2,629	2,621	2,614	2,606							$15,750
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.84%		483	482	481	479	478	476							2,879
8	Investment Expenses														
	a. Depreciation 3.34%		808	808	808	808	808	808							4,848
	b. Amortization		0	0	0	0	0	0							0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A							N/A
	d. Property Taxes 0.007269		177	177	177	177	177	177							1,062
	e. Other		0	0	0	0	0	0							0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,112	4,103	4,095	4,085	4,077	4,067							24,539
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0							0
	b. Recoverable Costs Allocated to Demand		4,112	4,103	4,095	4,085	4,077	4,067							24,539

HEARING EXHIBIT - 00000793

Docket 080007-EI
PEF's Responses to Staff's Fourth
Set of Interrogatories (Nos. 9-18)
Attachment 5

PROGRESS FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
Underground Storage Tanks (Project 10 Recap)

CPD
Page 1 of 1

(67,239)	(49 [illegible])	(16,630)
TOTAL COST	[illegible]	[illegible]
43,185	29,234	13,950
[illegible]	[illegible]	[illegible]

JULY 2007 T/M

For Project: UNDERGROUND STORAGE TANKS - CRYSTAL RIVER 4 & 5 (Project 10a)
(In Dollars)

Base

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$869	$0	$0	($49,259)	$0	$0	$0	$0	$0	$0	$0	($48,390)
	b. Clearings to Plant		0	0	0	0	0	168,941	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	(230)	(691)	(1,151)	(1,611)	(2,072)	(2,532)	(2,992)	
4	CWIP - Non-Interest Bearing	217,641	217,641	218,200	218,200	218,200	168,941	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$217,641	$217,641	$218,200	$218,200	$218,200	$168,941	$168,711	$168,251	$167,791	$167,330	$166,870	$166,409	$165,949	
6	Average Net Investment		217,641	217,921	218,200	218,200	193,571	168,826	168,481	168,021	167,560	167,100	166,640	166,179	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		2,024	2,027	2,029	2,029	1,800	1,570	1,567	1,563	1,558	1,554	1,550	1,545	$20,817
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		370	370	371	371	329	287	286	286	285	284	283	283	3,805
8	Investment Expenses														
	a. Depreciation 3.27%		0	0	0	0	0	230	460	460	460	460	460	460	2,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.016338		0	0	0	0	0	230	230	230	230	230	230	230	1,610
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,394	2,397	2,400	2,400	2,129	2,317	2,544	2,539	2,534	2,528	2,523	2,518	29,224
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,394	2,397	2,400	2,400	2,129	2,317	2,544	2,539	2,534	2,528	2,523	2,518	29,224

For Project: UNDERGROUND STORAGE TANKS - BARTOW (Project 10b)
(In Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$5,635	($3,156)	$0	$0	($21,609)	$599	$0	$0	$0	$0	$0	$0	($18,530)
	b. Clearings to Plant		0	0	0	0	0	75,868	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	75,868	75,868	75,868	75,868	75,868	75,868	75,868	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	(1,109)	(1,310)	(1,512)	(1,714)	(1,915)	(2,117)	(2,319)	
4	CWIP - Non-Interest Bearing	94,388	100,023	96,879	96,879	96,879	75,269	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$94,388	$100,023	$96,879	$96,879	$96,879	$75,269	$74,759	$74,558	$74,356	$74,154	$73,953	$73,751	$73,549	
6	Average Net Investment		97,206	98,456	96,879	96,879	86,074	74,859	74,658	74,457	74,255	74,053	73,852	73,650	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		904	916	901	901	800	(131)	694	692	691	689	687	685	$8,429
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		165	167	165	165	146	(24)	127	127	126	126	126	125	1,541
8	Investment Expenses														
	a. Depreciation 3.19%		0	0	0	0	0	1,111	202	202	202	202	202	202	2,321
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009773		0	0	0	0	0	372	62	62	62	62	62	62	743
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,069	1,083	1,066	1,066	947	1,328	1,065	1,062	1,060	1,078	1,078	1,074	13,033
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,069	1,083	1,066	1,066	947	1,328	1,065	1,062	1,060	1,078	1,078	1,074	13,033

HEARING EXHIBIT - 00000794

Docket 080007-EI
PEF's Responses to Staff's Fourth
Set of Interrogatories (Nos. 9-18)
Attachment 6

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
Underground Storage Tanks (Project 10 Romp)

CPD
Page 1 of 1

For Project: UNDERGROUND STORAGE TANKS - BARTOW (Project 10b)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		($18,530)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($18,530)
	b. Clearings to Plant		75,888	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	75,888	75,888	75,888	75,888	75,888	75,888	75,888	75,888	75,888	75,888	75,888	75,888	
3	Less: Accumulated Depreciation	0	(101)	(302)	(604)	(706)	(906)	(1,108)	(1,311)	(1,513)	(1,716)	(1,918)	(2,119)	(2,319)	
4	CWIP - Non-Interest Bearing	94,288	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$94,288	75,787	75,585	75,284	75,182	74,980	74,779	74,577	74,375	74,174	73,969	73,769	73,569	
6	Average Net Investment		85,062	75,686	75,435	75,283	75,081	74,880	74,678	74,476	74,274	74,063	73,851	73,649	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.15%	791	704	702	700	698	696	694	692	691	688	687	685	$8,429
	b. Debt Component (Line 5 x 2.04% x 1/12)	2.04%	145	129	128	128	128	127	127	127	126	126	126	125	1,541
8	Investment Expenses														
	a. Depreciation	3.18%	101	202	202	202	202	202	202	202	202	202	202	202	2,319
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009773	62	62	62	62	62	62	62	62	62	62	62	62	741
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,099	1,096	1,094	1,091	1,089	1,087	1,085	1,082	1,080	1,078	1,076	1,074	13,030
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,099	1,096	1,094	1,091	1,089	1,087	1,085	1,082	1,080	1,078	1,076	1,074	13,030

Docket 080007-EI
PEF's Responses to Staff's Fourth
Set of Interrogatories (Nos. 9-18)
Attachment 7

HEARING EXHIBIT - 00000795

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$62,994	$68,001	$16,922	$0	$0	$0	$0	$0	$0	$0	$0	$0	$147,916
	b. Clearings to Plant			0	0	147,916	0	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		$516,221	516,221	516,221	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	
3	Less: Accumulated Depreciation		(64,578)	(73,133)	(81,738)	(91,571)	(102,840)	(113,709)	(124,778)	(135,847)	(146,916)	(157,985)	(169,054)	(180,125)	(191,192)	
4	CWIP - Non-Interest Bearing		0	62,994	130,995	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$451,643	506,083	565,481	572,566	561,497	550,428	539,359	528,291	517,222	506,153	495,084	484,013	472,946	
6	Average Net Investment			478,863	536,782	569,023	567,032	555,963	544,894	533,825	522,756	511,687	500,618	489,548	478,480	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		4,454 (1)	4,993 (1)	5,292 (1)	5,273 (1)	5,170 (1)	5,068 (1)	4,966 (1)	4,862	4,759	4,656	4,553	4,450	$58,483
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		814 (2)	911 (2)	967 (2)	964 (2)	945 (2)	926 (2)	908 (2)	888	870	851	832	813	10,690
8	Investment Expenses															
	a. Depreciation (C)	20.00%		8,554 (3)	8,604 (3)	9,836 (3)	11,069 (3)	11,069 (3)	11,069 (3)	11,069 (3)	11,069	11,069	11,069	11,069	11,069	126,564
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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)	0.016336		874 (4)	703 (4)	904 (4)	904 (4)	904 (4)	904 (4)	904 (4)	904	904	904	904	904	10,319
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,445	15,200	16,999	18,211	18,088	17,967	17,845	17,723	17,602	17,480	17,358	17,236	206,155
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			14,445	15,200	16,999	18,211	18,088	17,967	17,845	17,723	17,602	17,480	17,358	17,236	206,155
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.93753	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)			13,543	14,250	15,937	17,073	16,959	16,845	16,730	16,616	16,502	16,388	16,274	16,159	193,276
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$13,543	$14,250	$15,937	$17,073	$16,959	$16,845	$16,730	$16,616	$16,502	$16,388	$16,274	$16,159	$193,276

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 8.85%, 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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
line 6c Based on 2005 Rate Case Settlement in Dkt. 050078-EI.

Σ ①'s = 35,205
Σ ②'s = 6,435
Σ ③'s = 71,320
Σ ④'s = 5,797

HEARING EXHIBIT - 00000796

Docket 080007-EI
PEF's Responses to Staff's Fourth
Set of Interrogatories (Nos. 9-18)
Attachment 8

24

PEF's response to Staff's Fifth Set of Interrogatories (Nos. 19 - 25)

HEARING EXHIBIT - 00000797

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 080007-EI
	DATED: October 13, 2008

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 19-25)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Fifth Set of Interrogatories (Nos. 19-25):

RESPONSES

19. **In the schedule of Project 4.1c shown on page 3 of 13 of Exhibit WG-2 filed on April 2, 2008, the total system recoverable expenses (Line 9) are $298,468. However, in the schedule of Project 4.1c shown in Attachment C to PEF's response to staff's second request for PODs (No. 2), the total system recoverable expenses (Line 9) for the same project are $285,336. Please reconcile these two numbers and provide an amended schedule for Project 4.1c.**

Answer: In the last two sentences in the first paragraph of PEF's response to staff's second request for PODs (No. 2), PEF stated that the corrected schedules (i.e. Attachment C) were only used for the purpose of calculating the correct return through the month (i.e. March 2007) the correction was made and not as the basis for any part of the schedule (i.e. Exhibit WG-2) after that month. This revised schedule (Attachment C) was created in March 2007 only for the purposes of calculating the adjustment to return that was necessary for January and February 2007 that were not recorded correctly. This adjustment was added to the March 2007 return in Line 7b. Therefore, the comparison between the total system recoverable expenses of $298,468 and $285,336 is not a meaningful comparison because the amount per Exhibit WG-2 was also based on the actual activity that occurred from April through December 2007, which was not included as part of Attachment C per the reasons cited above. Based on the reasons cited in this response, an amended schedule will not be provided.

20. **In the schedule of Project 4.1e shown on page 4 of 13 of Exhibit WG-2 filed on April 2, 2008, the figure on Line 2 PIS for December showed a discrepancy compared to**

the rest of the months of the year. If the same formula applied, the December amount should be $352,593 rather than $349,609 as filed. If this calculation is correct, please provide an amended schedule for Project 4.1e. If this calculation is not correct, please explain.

Answer: In December 2007, a project cost reconciliation was performed and PEF determined that $2,984 was incorrectly recorded to the project twice during 2007. Because the amount was not a true credit to the project per the project accounting system in December 2007, it was not included in line 1a and 1b. Instead, the amount was subtracted directly from Line 2 to correct the Plant In Service balance going forward. Based on the reasons cited in this response, an amended schedule will not be provided.

21. **In PEF's response to staff's second request for PODs (No. 2) dated July 31, 2008, it stated that "Project 4.1d and Project 4.1h also include immaterial return on equity true-ups totaling a decrease of $90 and return on debt true-ups totaling a decrease of $17 due to other minor calculation errors." Please provide amended schedules for 4.1d and 4.1h.**

Answer: The 2006 return on equity and debt were not filed correctly for Projects 4.1d (Avon Park) and 4.1h (University of Florida) in Exhibit WG-2 from Docket 070007-EI due to use of an incorrect in-service date. Attachments 1 and 2 show the schedules that were used for purposes of calculating the adjustments needed to correct the return for 2006 and these adjustments were added to the return on equity and debt in January 2007 in line 7a and 7b. Project 4.1d had adjustments of ($4) and ($1) and Project 4.1h had adjustments of ($86) and ($16) to return on equity and debt respectively. An amended schedule will not be provided due to the reasons included in this response.

22. **Based on the responses to the above Interrogatories Nos. 19, 20 and 21, please provide an amended schedule for project 4.1 of the Actual True-up Jan. 2007 through Dec. 2007.**

Answer: See responses for Nos. 19, 20, and 21. Amended schedules are not applicable.

23. **In the schedule Deferred Gain on Sales of Emissions Allowances (Project 5), on page 13 of 21, of Exhibit WG-1 filed on April 2, 2008, please explain or describe the following and provide an amended schedule for Project 5:**

a. **Why is the amount shown in January for Line 1a a discrepancy compared to the amounts listed in the same line for the other months of the year when using the same calculation formula.**

b. **Why is the amount shown in May for Line 1b in discrepancy compared to the amounts listed in the same line for the other months of the year when using the same calculation formula.**

Answer: In January 2007, there was a purchase of SO2 allowances for $10,400,000 so this amount increased the SO2 Emission Allowance Inventory in line 1a in January. In May 2007, the EPA purchased SO2 allowances from PEF for $1,098,566 which increased the Auctioned SO2 Allowance liability in line 1b in May. Due to the reasons included in this response, an amended schedule will not be provided.

24. **In the schedule Deferred Gain on Sales of Emissions Allowances (Project 5), on page 13 of 22, of Exhibit LC-1 filed on August 4, 2008, please explain or describe the following and provide an amended schedule for Project 5:**

a. **Why is the amount shown in January for Line 1a a discrepancy compared to the amounts listed in the same line for the other months of the year when using the same calculation formula.**

b. **Why is the amount shown in May for Line 1b a discrepancy compared to the amounts listed in the same line for the other months of the year when using the same calculation formula.**

Answer: In January 2008, there was a purchase of SO2 allowances for $23,027,500 so this amount increased the SO2 Emission Allowance Inventory in line 1a in January. In May 2008, the EPA purchased SO2 allowances from PEF for $906,201 which increased the Auctioned SO2 Allowance liability in line 1b in May. Due to the reasons included in this response, an amended schedule will not be provided.

25. **In the schedule Deferred Gain on Sales of Emissions Allowances (Project 5), on page 9 of 32, of Exhibit LC-3 filed on August 29, 2008, please explain or describe the following and provide an amended schedule for Project 5:**

a. **Why is the amount shown in May for Line 1b a discrepancy compared to the amounts listed in the same line for the other months of the year when using the same calculation formula.**

b. Why is the amount shown in April for Line 1c a discrepancy compared to the amounts listed in the same line for the other months of the year when using the same calculation formula.

Answer: 25(a) – The calculation is correct and no amended schedule will be provided. Line 1b represents the proceeds received for the allowances withheld by the EPA for auction. The auction proceeds are amortized during their vintage year. PEF receives the auction proceeds and then amortizes them over the year via two accounts: Auctioned SO2 Allowance (Line 1b) and SO2 Amortization Expense (Line 6b). The discrepancy seen in May on Line 1b represents the receipt of the 2009 proceeds, less the amortization for the first five months of the year. The 2009 proceeds based on the formula provided by the EPA were projected to be $560,489. The amortization expense of these proceeds for the first five months of the year was calculated to be $233,537 ($560,489/12*5). There is an additional $11,795 in amortization expense related to the amortization of advance purchased allowances. By taking the April ending balance of ($2,016,074) less the amortization expense of ($245, 332) [$233,537+$11,795] plus the annual proceeds received for the current year auction of $560,489 the May balance of ($2,331,231) is achieved.

25(b) – The calculation is correct and no amended schedule will be provided. Line 1c represents the NOx Emission Inventory Balance. The following is the formula to calculate the inventory balance: Beg Balance + Purchases – Expenses = Ending Balance. The schedule in question only provides stand alone lines for three of the four variables: Beginning Balance, Expense and Ending Balance. Prior to April 2009, there were no purchases allowing for a direct calculation [Line 1c – Line 6c] resulting in the next month balance on Line 1c being straightforward. In April 2009, however, there was a purchase of $7,160,625 which is included within Line 1c resulting in an indirect calculation of the formula demonstrated above. By isolating this purchase, the calculation of the balance is as follows:
(Line 1c-March) $53,614,523 + (Purchase) $7,160,625 – (Line6c-April) $3,892,117= (Line 1c-April) $56,883,031.

DATED this 13th day of October, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500
Attorneys for Progress Energy Florida, Inc.

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

Peaking [redacted]
20048148

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		715	-	52,815	60,991	32,011	-	-	-	-	28,594	-	-	175,126
	b. Clearings to Plant		-	-	-	-	-	-	-	150,344	-	28,594	-	-	
	c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other		-	-	-	-	-	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base	-	-	-	-	-	-	-	-	150,344	150,344	178,938	178,938	178,938	
3	Less: Accumulated Depreciation	-	-	-	-	-	-	-	-	(437)	(875)	(1,395)	(1,915)	(2,436)	
4	CWIP - Non-Interest Bearing	3,812	4,527	4,527	57,342	118,333	150,344	150,344	150,344	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	3,812	4,527	4,527	57,342	118,333	150,344	150,344	150,344	149,906	149,469	177,543	177,023	176,502	
6	Average Net Investment		4,170	4,527	30,935	87,837	134,338	150,344	150,344	150,125	149,688	163,506	177,283	176,762	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		39	42	288	817	1,249	1,398	1,398	1,396	1,392	1,521	1,649	1,644	12,833
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		7	8	53	149	228	256	256	255	254	278	301	300	2,346
8	Investment Expenses														
	a. Depreciation 3.49%		-	-	-	-	-	-	-	437	437	520	520	520	2,436
	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 0.010473		-	-	-	-	-	-	-	131	131	156	156	156	731
	e. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)		46	50	340	966	1,478	1,654	1,654	2,220	2,215	2,475	2,627	2,621	18,345
	a. Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand		46	50	340	966	1,478	1,654	1,654	2,220	2,215	2,475	2,627	2,621	18,345

HEARING EXHIBIT - 00000802

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

Docket 080007-EI
PEF's Responses to Staff's Fifth Set of Interrogatories (Nos. 19-25)
Attachment 2

Pending [illegible]
20050976

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		23,365	26,391	-	-	-	-	-	-	-	-	-	-	49,756
	b. Clearings to Plant		-	141,435	-	-	-	-	-	-	-	-	-	-	
	c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other		-	-	-	-	-	-	-	-	-	-	-	-	
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	
3	Less: Accumulated Depreciation	-	-	(794)	(1,589)	(2,383)	(3,178)	(3,972)	(4,766)	(5,561)	(6,355)	(7,150)	(7,944)	(8,738)	
4	CWIP - Non-Interest Bearing	91,679	115,044	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	91,679	115,044	140,641	139,846	139,052	138,257	137,463	136,669	135,874	135,080	134,285	133,491	132,697	
6	Average Net Investment		103,362	127,842	140,243	139,449	138,655	137,860	137,066	136,271	135,477	134,683	133,888	133,094	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		961	1,189	1,304	1,297	1,289	1,282	1,275	1,267	1,260	1,253	1,245	1,238	14,860
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		176	217	238	237	236	234	233	232	230	229	228	226	2,716
8	Investment Expenses														
	a. Depreciation 6.74%		-	794	794	794	794	794	794	794	794	794	794	794	8,738
	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 0.017522		-	207	207	207	207	207	207	207	207	207	207	207	2,272
	e. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)		1,137	2,407	2,544	2,535	2,526	2,517	2,509	2,500	2,491	2,482	2,474	2,465	28,587
	a. Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand		1,137	2,407	2,544	2,535	2,526	2,517	2,509	2,500	2,491	2,482	2,474	2,465	28,587

HEARING EXHIBIT - 00000803

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared WILL GARRETT, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 19 through 24 of Staff's 5th Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 080007-EI are true and correct to the best of his knowledge, information and belief.

Will Garrett

PEF - Controller
Title

SUZANNE H. MILLER
MY COMMISSION # DD 411455
EXPIRES: March 27, 2009
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida

My commission Expires:
3/27/09

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared Lori Cross, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory No. 25 of Staff's 5th Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 080007-EI are true and correct to the best of her knowledge, information and belief.

Lori J. Cross
Lori Cross

Mgr. Reg. Planning
Title

SUZANNE H. MILLER
MY COMMISSION # DD 411455
EXPIRES: March 27, 2009
Bonded Thru Notary Public Underwriters

Suzanne H. Miller
Notary Public
State of Florida

My commission Expires:
3/27/09

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PEF's response to Staff's Sixth Set of Interrogatories (No. 26)

HEARING EXHIBIT - 00000806

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 080007-EI
	DATED: October 20, 2008

PROGRESS ENERGY FLORIDA'S RESPONSE TO STAFF'S SIXTH SET OF INTERROGATORIES (NO. 26)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Sixth Set of Interrogatories (No. 26):

RESPONSE

26. **Please refer to the testimony of Lori Cross filed August 29, 2009, exhibit LC-3, page 3 of 32, line 3, which shows total costs allocated to energy as $74,695,222. Please show how this total is calculated (activities 5, 7.4, and 12 under line 1 do not appear to add up to the total shown on line 3).**

Answer: The calculation of the total costs allocated to energy on Form 42-2P line 3 is as follows:

Project No.	Project Description	End of Period Total
Line 1 - 5	SO2 and NOx Emissions	$71,976,198
Line 1 - 7.4	CAIR/CAMR Crystal River AFUDC	2,662,344
Line 1 - 12	Greenhouse Gas Inventory & Reporting	56,680
	Energy per Line 1: TOTAL	**$74,695,222**
Line 3	Recoverable Costs Allocated to Energy	$74,695,222
	Difference	**$ -**

DATED this 20th day of October, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared Lori Cross, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory No. 26 of Staff's 6th Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 080007-EI are true and correct to the best of her knowledge, information and belief.

Lori G. Cross
Lori Cross

Mgr. Regulatory Planning
Title

SUZANNE H. MILLER
MY COMMISSION # DD 411455
EXPIRES: March 27, 2009
Bonded Thru Notary Public Underwriters

Suzanne H. Miller
Notary Public
State of Florida

My commission Expires:
3/27/09

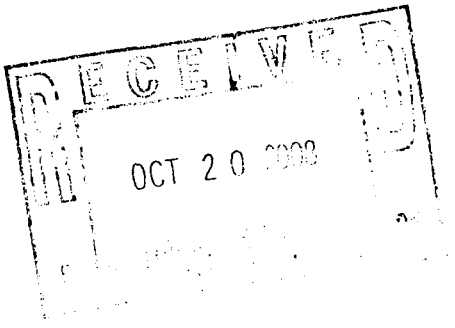
HEARING EXHIBIT - 00000809

Hopping Green & Sams

Attorneys and Counselors

Writer's Direct Dial Number
(850) 425-2359

October 20, 2008



BY HAND DELIVERY

Ann Cole
Director, Office of the Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 080007-EI
Notice of Service of Discovery Response

Dear Ms. Cole:

Please take notice that Progress Energy Florida, Inc. has today served its Response to Staff's Sixth Set of Interrogatories (No. 26).

By copy of this letter, the response has been furnished to all parties of record.

If you have any questions regarding this notice, please give me a call at 425-2359.

Very truly yours,

Gary V. Perko

GVP/dg
Enclosures
cc: Certificate of Service

HEARING EXHIBIT - 00000810

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished to all counsel of record and interested parties as listed below by hand-delivery (*) or regular U.S. mail this 20th day of October, 2008.

Martha Carter Brown (*)
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Lee L. Willis, Esq.
James D. Beasley, Esq.
Ausley Law Firm
P.O. Box 391
Tallahassee, FL 32302

Joseph McGlothlin, Esq.
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Rm. 812
Tallahassee, FL 32399

Jeffrey A. Stone, Esq.
Russell A. Badders, Esq.
Beggs & Lane Law Firm
P.O. Box 12950
Pensacola, FL 32591-2950

Florida Industrial Power Users Group
John W. McWhirter, Jr.
c/o McWhirter Law Firm
P.O. Box 3350
Tampa, FL 33601-3350

Florida Power & Light Co.
R. Wade Litchfield, Esq.
John T. Butler, Esq.
700 Universe Blvd.
Juno Beach, FL 33408-0420

Florida Power & Light Co.
Mr. Wade Litchfield
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301

Gulf Power Company
Susan Ritenour
One Energy Place
Pensacola, FL 32520-0780

Tampa Electric Company
Paula K. Brown
Regulatory Affairs
P.O. Box 111
Tampa, FL 33601-0111

R. Alexander Glenn
Deputy General Counsel - Florida
Progress Energy Service Company, LLC
P.O. Box 14042
St. Petersburg, FL 33733

John T. Burnett
Associate General Counsel - Florida
Progress Energy Service Company, LLC
P.O. Box 14042
St. Petersburg, FL 33733

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740

Attorney

26

Gulf's Response to Staff's First Request for Production of Documents (No. 1)

1. Referring to the testimony of Rhonda Martin dated April 2, 2008, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Schedule 8A attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

ANSWER:

In accordance with FPSC Order No. PSC-94-0044-FOF-EI, the rate of return used to develop the revenue requirements of ECRC investment is based on the capital structure and cost rates approved in Gulf's last rate case, Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI, dated June 10, 2002.

Gulf Power Company
Environmental Cost Recovery Clause
Calculation of Revenue Requirement Rate of Return

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Notes:
(1) Capital Structure Approved by FPSC on April 26, 2002 in Doc. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on April 26, 2002 in Doc. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

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Gulf's Response to Staff's Second Request for Production of Documents (Nos. 2 - 5)

2. Regarding the proposed Plant Smith SPCC Compliance Project, please provide the following:

   a. The original and the revised versions of Title 40 CFR Part 112.8(c), the SPCC regulation as commonly referred;

   b. Any and all workpapers that were used to derive the estimated 2009 Capital expenditures: $20,000 ± 20%;

   c. Any and all workpapers that were used to derive the estimated 2009 O&M expenses: $5,000 ± 20%.

ANSWER:

2(a) - The SPCC regulation that was in place prior to the July 2002 revision and subsequent amendments is included as Attachment A. The current SPCC regulation is provided in Attachment B. The revised SPCC regulation defines bulk storage containers as "any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container." According to the General Applicability section, 112.1(5), the revised SPCC regulation does not apply to "any container with a storage capacity of less than 55 gallons of oil."

2(b) - The Plant Smith SPCC capital cost estimate was based on a June 2008 proposal from Alabama Metal Fabricators, Inc. (AMF) to construct a concrete secondary containment area for a padmount transformer. The AMF quote is included as Attachment C.

2(c) - The O&M cost estimate was based on working knowledge from similar aboveground storage tank containment projects.

3. Regarding the proposed Plant Crist Water Conservation Project, please provide the following:

   a. A copy of the previously approved "Plant Crist Water Conservation and Consumptive Use Efficiency Program";

   b. A copy of all documents in FPL's possession related to Gulf Power Company's negotiations with Emerald Coast Utilities Authority for utilizing reclaimed water from the utility's new wastewater treatment plant;

   c. Any and all workpapers that Gulf Power used to derive the estimated 2009 Capital expenditures: $17,000,000 ± 20%;

   d. The detailed scope of the project.

ANSWER:

3(a) - A copy of the Plant Crist Consumptive Use permit and correspondence regarding measures Plant Crist has taken to conserve water are included in Attachment D. During 2006 Plant Crist installed automatic level controls on the fire water tanks to reduce groundwater usage. The FPSC granted ECRC approval for recovery of the Plant Crist level controls in Order No. PSC-05-1251-FOF-EI.

3(b) and 3(c) - Per discussion with Staff counsel, Gulf will provide the contract and documentation responsive to this request after negotiations have been completed.

3(d) - See Attachment E.

4. Regarding the proposed Impaired Waters Rule (IWR) Project, please provide the following:

   a. A copy of the FDEP proposed listing of waters in watersheds surrounding Gulf's generating facilities for nutrients and mercury;

   b. Any and all workpapers that Gulf Power used to derive the estimated 2009 O&M expenditures: $100,000 ± 30%;

   c. The detailed scope of the project.

ANSWER:

4(a) - The requested documents are provided as Attachments F, G, H and I.

The map entitled "Map of Hg Impaired Waterbodies" depicts areas in the state of Florida where water quality standards for mercury (Hg) have not been attained. These areas are illustrated in red on the map. This includes the Pensacola Bay system and Escambia River near Plant Crist in Pensacola, FL. The St. Andrews Bay system, which is near Plant Smith in Southport, FL, is also listed for impairment for mercury. Plant Scholz is located in Sneads, FL along the Apalachicola River. The Apalachicola Bay and surrounding Gulf waters are also illustrated as being impaired. There are many contributing factors to the listing of mercury (i.e. global pool of mercury from sources outside of the US as well as natural sources) and a modeling effort will mostly will be required to determine what effect, if any, Gulf's generating facilities may have on these water bodies.

Nutrient listings are also provided in Attachments G through I. These documents illustrate the nutrient as well as other listed impairments in the Apalachicola River (Attachment G), St. Andrews Bay system (Attachment H), and Pensacola Bay system (Attachment I). It should be noted that chlorophyll is a listed impairment that results from nutrients. In addition, in some cases dissolved oxygen listings can be a result of algal populations and other environmental factors. Therefore these parameters, which can be a result of nutrients, may also need to be evaluated.

4. Regarding the proposed Impaired Waters Rule (IWR) Project, please provide the following:

   a. A copy of the FDEP proposed listing of waters in watersheds surrounding Gulf's generating facilities for nutrients and mercury;

   b. Any and all workpapers that Gulf Power used to derive the estimated 2009 O&M expenditures: $100,000 ± 30%;

   c. The detailed scope of the project.

ANSWER:

4(b) - The estimated O&M expenses were derived from a verbal cost estimate from HydroQual, Inc. The verbal estimate from HydroQual was $100,000 per facility. In discussions with HydroQual, Gulf determined the possible need for both hydrodynamic and water quality modeling. Hydrodynamic modeling involves running a model that predicts the effects of wave action, currents and water flow into the system and how these factors affect concentrations of parameters such as nutrients, etc. The water quality modeling portion of the project involves how inputs into the water body as well as existing concentrations are affected by dispersion and diffusion of the various parameters.

If it is deemed necessary to expand the modeling effort to determine if Gulf Power needs to make any reductions in loadings, additional modeling such as air modeling or other studies (surface water or sediment sampling) may be required. This level of study may be required to evaluate the impact of Gulf's permitted industrial wastewater discharges.

4(c) - The IWR project scope has been discussed in response to item 4(b). In summary, water quality in the water bodies around Gulf's generating facilities may need to be modeled to evaluate Gulf's permitted industrial wastewater discharges. As previously discussed, additional sampling or modeling may be required to fully evaluate these sites.

5. Regarding the proposed Annual Climate Registry Fees, please provide any and all workpapers that Gulf Power used to derive the estimated 2009 O&M Expenditures: $8,000 ± 30%.

Answer:

See Attachment J.

The estimated cost for Gulf's initial climate registry fee and historical data reporting is $7,500. The initial registration fee will be based on Gulf's revenue. The initial registration fee for organizations with revenues between $500 million to $ 2 billion is $6,000. The historical data reporting fee is 25 % of the registration fee which would be $1,500 for Gulf.

Attachment A

HEARING EXHIBIT - 00000821

OF THE INTERIOR, SECRETARY OF TRANSPORTATION, AND ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY
APPENDIX C TO PART 112—SUBSTANTIAL HARM CRITERIA
APPENDIX D TO PART 112—DETERMINATION OF A WORST CASE DISCHARGE PLANNING VOLUME
APPENDIX E TO PART 112—DETERMINATION AND EVALUATION OF REQUIRED RESPONSE RESOURCES FOR FACILITY RESPONSE PLANS
APPENDIX F TO PART 112—FACILITY-SPECIFIC RESPONSE PLAN

AUTHORITY: 33 U.S.C. 1251 *et seq.*; 33 U.S.C. 2720; E.O. 12777 (October 18, 1991), 3 CFR, 1991 Comp., p. 351.

SOURCE: 38 FR 34165, Dec. 11, 1973, unless otherwise noted.

EDITORIAL NOTE: Nomenclature changes to part 112 appear at 65 FR 40798, June 30, 2000.

§ 112.1 General applicability.

(a) This part establishes procedures, methods and equipment and other requirements for equipment to prevent the discharge of oil from non-transportation-related onshore and offshore facilities into or upon the navigable waters of the United States or adjoining shorelines.

(b) Except as provided in paragraph (d) of this section, this part applies to owners or operators of non-transportation-related onshore and offshore facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing or consuming oil and oil products, and which, due to their location, could reasonably be expected to discharge oil in harmful quantities, as defined in part 110 of this chapter, into or upon the navigable waters of the United States or adjoining shorelines.

(c) As provided in section 313 (86 Stat. 875) departments, agencies, and instrumentalities of the Federal government are subject to these regulations to the same extent as any person, except for the provisions of § 112.6.

(d) This part does not apply to:

(1) Facilities, equipment or operations which are not subject to the jurisdiction of the Environmental Protection Agency, as follows:

(i) Onshore and offshore facilities, which, due to their location, could not reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines. This determination shall be based solely upon a consideration of the geographical, locational aspects of the facility (such as proximity to navigable waters or adjoining shorelines, land contour, drainage, etc.) and shall exclude consideration of manmade features such as dikes, equipment or other structures which may serve to restrain, hinder, contain, or otherwise prevent a discharge of oil from reaching navigable waters of the United States or adjoining shorelines; and

(ii) Equipment or operations of vessels or transportation-related onshore and offshore facilities which are subject to authority and control of the Department of Transportation, as defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, dated November 24, 1971, 36 FR 24000.

(2) Those facilities which, although otherwise subject to the jurisdiction of the Environmental Protection Agency, meet both of the following requirements:

(i) The underground buried storage capacity of the facility is 42,000 gallons or less of oil, and

(ii) The storage capacity, which is not buried, of the facility is 1,320 gallons or less of oil, provided no single container has a capacity in excess of 660 gallons.

(e) This part provides for the preparation and implementation of Spill Prevention Control and Countermeasure Plans prepared in accordance with § 112.7, designed to complement existing laws, regulations, rules, standards, policies and procedures pertaining to safety standards, fire prevention and pollution prevention rules, so as to form a comprehensive balanced Federal/State spill prevention program to minimize the potential for oil discharges. Compliance with this part does not in any way relieve the owner or operator of an onshore or an offshore facility from compliance with other Federal, State or local laws.

[38 FR 34165, Dec. 11, 1973, as amended at 41 FR 12657, Mar. 26, 1976]

§ 112.2 Definitions.

For the purposes of this part:

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Adverse weather means the weather conditions that make it difficult for response equipment and personnel to cleanup or remove spilled oil, and that will be considered when identifying response systems and equipment in a response plan for the applicable operating environment. Factors to consider include significant wave height as specified in Appendix E to this part, as appropriate, ice conditions, temperatures, weather-related visibility, and currents within the area in which the systems or equipment are intended to function.

Animal fat means a non-petroleum oil, fat, or grease of animal, fish, or marine mammal origin.

Complex means a facility possessing a combination of transportation-related and non-transportation-related components that is subject to the jurisdiction of more than one Federal agency under section 311(j) of the Clean Water Act.

Contract or other approved means: (1) A written contractual agreement with an oil spill removal organization(s) that identifies and ensures the availability of the necessary personnel and equipment within appropriate response times; and/or

(2) A written certification by the owner or operator that the necessary personnel and equipment resources, owned or operated by the facility owner or operator, are available to respond to a discharge within appropriate response times; and/or

(3) Active membership in a local or regional oil spill removal organization(s) that has identified and ensures adequate access through such membership to necessary personnel and equipment to respond to a discharge within appropriate response times in the specified geographic areas; and/or

(4) Other specific arrangements approved by the Regional Administrator upon request of the owner or operator.

Discharge includes but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying or dumping. For purposes of this part, the term *discharge* shall not include any discharge of oil which is authorized by a permit issued pursuant to section 13 of the River and Harbor Act of 1899 (30 Stat. 1121, 33 U.S.C. 407), or sections 402 or 405 of the FWPCA Amendments of 1972 (86 Stat. 816 *et seq.*, 33 U.S.C. 1251 *et seq.*).

Fish and wildlife and sensitive environments means areas that may be identified by either their legal designation or by evaluations of Area Committees (for planning) or members of the Federal On-Scene Coordinator's spill response structure (during responses). These areas may include wetlands, National and State parks, critical habitats for endangered/threatened species, wilderness and natural resource areas, marine sanctuaries and estuarine reserves, conservation areas, preserves, wildlife areas, wildlife refuges, wild and scenic rivers, recreational areas, national forests, Federal and State lands that are research national areas, heritage program areas, land trust areas, and historical and archeological sites and parks. These areas may also include unique habitats such as: aquaculture sites and agricultural surface water intakes, bird nesting areas, critical biological resource areas, designated migratory routes, and designated seasonal habitats.

Injury means a measurable adverse change, either long- or short-term, in the chemical or physical quality or the viability of a natural resource resulting either directly or indirectly from exposure to a discharge of oil, or exposure to a product of reactions resulting from a discharge of oil.

Maximum extent practicable means the limitations used to determine oil spill planning resources and response times for on-water recovery, shoreline protection, and cleanup for worst case discharges from onshore non- transportation-related facilities in adverse weather. It considers the planned capability to respond to a worst case discharge in adverse weather, as contained in a response plan that meets the requirements in § 112.20 or in a specific plan approved by the Regional Administrator.

The term *navigable waters* of the United States means *navigable waters* as defined in section 502(7) of the FWPCA, and includes:

(1) All navigable waters of the United States, as defined in judicial decisions prior to passage of the 1972 Amendments to the FWPCA (Pub. L. 92–500), and tributaries of such waters;

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(2) Interstate waters;

(3) Intrastate lakes, rivers, and streams which are utilized by interstate travelers for recreational or other purposes; and

(4) Intrastate lakes, rivers, and streams from which fish or shellfish are taken and sold in interstate commerce.

Navigable waters do not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other federal agency, for the purposes of the Clean Water Act, the final authority regarding Clean Water Act jurisdiction remains with EPA.

Non-petroleum oil means oil of any kind that is not petroleum-based, including but not limited to: Fats, oils, and greases of animal, fish, or marine mammal origin; and vegetable oils, including oils from seeds, nuts, fruits, and kernels.

Offshore facility means any facility of any kind located in, on, or under any of the navigable waters of the United States, which is not a transportation-related facility.

Oil means oil of any kind or in any form, including, but not limited to petroleum, fuel oil, sludge, oil refuse and oil mixed with wastes other than dredged spoil.

Oil Spill Removal Organization means an entity that provides oil spill response resources, and includes any for-profit or not-for-profit contractor, cooperative, or in-house response resources that have been established in a geographic area to provide required response resources.

Onshore facility means any facility of any kind located in, on, or under any land within the United States, other than submerged lands, which is not a transportation-related facility.

Owner or operator means any person owning or operating an onshore facility or an offshore facility, and in the case of any abandoned offshore facility, the person who owned or operated such facility immediately prior to such abandonment.

Person includes an individual, firm, corporation, association, and a partnership.

Petroleum oil means petroleum in any form, including but not limited to crude oil, fuel oil, mineral oil, sludge, oil refuse, and refined products.

Regional Administrator, means the Regional Administrator of the Environmental Protection Agency, or his designee, in and for the Region in which the facility is located.

Spill event means a discharge of oil into or upon the navigable waters of the United States or adjoining shorelines in harmful quantities, as defined at 40 CFR part 110.

Transportation-related and *non-transportation-related* as applied to an onshore or offshore facility, are defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, dated November 24, 1971, 36 FR 24080.

United States means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Canal Zone, Guam, American Samoa, the Virgin Islands, and the Trust Territory of the Pacific Islands.

Vegetable oil means a non-petroleum oil or fat of vegetable origin, including but not limited to oils and fats derived from plant seeds, nuts, fruits, and kernels.

Vessel means every description of watercraft or other artificial contrivance used, or capable of being used as a means of transportation on water, other than a public vessel.

Worst case discharge for an onshore non-transportation-related facility means the largest foreseeable discharge in adverse weather conditions as determined using the worksheets in Appendix D to this part.

[38 FR 34165, Dec. 11, 1973, as amended at 58 FR 45039, Aug. 25, 1993; 59 FR 34097, July 1, 1994; 65 FR 40798, June 30, 2000]

§ 112.3 Requirements for preparation and implementation of Spill Prevention Control and Countermeasure Plans.

(a) Owners or operators of onshore and offshore facilities in operation on or before the effective date of this part that have discharged or, due to their location, could reasonably be expected to discharge oil in harmful quantities, as defined in 40 CFR part 110, into or upon the navigable waters of the United States or adjoining shorelines,

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shall prepare a Spill Prevention Control and Countermeasure Plan (hereinafter "SPCC Plan"), in writing and in accordance with §112.7. Except as provided for in paragraph (f) of this section, such SPCC Plan shall be prepared within six months after the effective date of this part and shall be fully implemented as soon as possible, but not later than one year after the effective date of this part.

(b) Owners or operators of onshore and offshore facilities that become operational after the effective date of this part, and that have discharged or could reasonably be expected to discharge oil in harmful quantities, as defined in 40 CFR part 110, into or upon the navigable waters of the United States or adjoining shorelines, shall prepare an SPCC Plan in accordance with §112.7. Except as provided for in paragraph (f) of this section, such SPCC Plan shall be prepared within six months after the date such facility begins operations and shall be fully implemented as soon as possible, but not later than one year after such facility begins operations.

(c) Owners or operators of onshore and offshore mobile or portable facilities, such as onshore drilling or workover rigs, barge mounted offshore drilling or workover rigs, and portable fueling facilities shall prepare and implement an SPCC Plan as required by paragraphs (a), (b) and (d) of this section. The owners or operators of such facility need not prepare a new SPCC Plan each time the facility is moved to a new site. The SPCC Plan may be a general plan, prepared in accordance with §112.7, using good engineering practice. When the mobile or portable facility is moved, it must be located and installed using the spill prevention practices outlined in the SPCC Plan for the facility. No mobile or portable facility subject to this regulation shall operate unless the SPCC Plan has been implemented. The SPCC Plan shall only apply while the facility is in a fixed (non-transportation) operating mode.

(d) No SPCC Plan shall be effective to satisfy the requirements of this part unless it has been reviewed by a Registered Professional Engineer and certified to by such Professional Engineer. By means of this certification the engineer, having examined the facility and being familiar with the provisions of this part, shall attest that the SPCC Plan has been prepared in accordance with good engineering practices. Such certification shall in no way relieve the owner or operator of an onshore or offshore facility of his duty to prepare and fully implement such Plan in accordance with §112.7, as required by paragraphs (a), (b) and (c) of this section.

(e) Owners or operators of a facility for which an SPCC Plan is required pursuant to paragraph (a), (b) or (c) of this section shall maintain a complete copy of the Plan at such facility if the facility is normally attended at least 8 hours per day, or at the nearest field office if the facility is not so attended, and shall make such Plan available to the Regional Administrator for on-site review during normal working hours.

(f) *Extensions of time.* (1) The Regional Administrator may authorize an extension of time for the preparation and full implementation of an SPCC Plan beyond the time permitted for the preparation and implementation of an SPCC Plan pursuant to paragraph (a), (b) or (c) of this section where he finds that the owner or operator of a facility subject to paragraphs (a), (b) or (c) of this section cannot fully comply with the requirements of this part as a result of either nonavailability of qualified personnel, or delays in construction or equipment delivery beyond the control and without the fault of such owner or operator or their respective agents or employees.

(2) Any owner or operator seeking an extension of time pursuant to paragraph (f)(1) of this section may submit a letter of request to the Regional Administrator. Such letter shall include:

(i) A complete copy of the SPCC Plan, if completed;

(ii) A full explanation of the cause for any such delay and the specific aspects of the SPCC Plan affected by the delay;

(iii) A full discussion of actions being taken or contemplated to minimize or mitigate such delay;

(iv) A proposed time schedule for the implementation of any corrective actions being taken or contemplated, including interim dates for completion of

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tests or studies, installation and operation of any necessary equipment or other preventive measures.

In addition, such owner or operator may present additional oral or written statements in support of his letter of request.

(3) The submission of a letter of request for extension of time pursuant to paragraph (f)(2) of this section shall in no way relieve the owner or operator from his obligation to comply with the requirements of § 112.3 (a), (b) or (c). Where an extension of time is authorized by the Regional Administrator for particular equipment or other specific aspects of the SPCC Plan, such extension shall in no way affect the owner's or operator's obligation to comply with the requirements of § 112.3 (a), (b) or (c) with respect to other equipment or other specific aspects of the SPCC Plan for which an extension of time has not been expressly authorized.

[38 FR 34165, Dec. 11, 1973, as amended at 41 FR 12657, Mar. 26, 1976]

§ 112.4 Amendment of SPCC Plans by Regional Administrator.

(a) Notwithstanding compliance with § 112.3, whenever a facility subject to § 112.3 (a), (b) or (c) has: Discharged more than 1,000 U.S. gallons of oil into or upon the navigable waters of the United States or adjoining shorelines in a single spill event, or discharged oil in harmful quantities, as defined in 40 CFR part 110, into or upon the navigable waters of the United States or adjoining shorelines in two spill events, reportable under section 311(b)(5) of the FWPCA, occurring within any twelve month period, the owner or operator of such facility shall submit to the Regional Administrator, within 60 days from the time such facility becomes subject to this section, the following:

(1) Name of the facility;

(2) Name(s) of the owner or operator of the facility;

(3) Location of the facility;

(4) Date and year of initial facility operation;

(5) Maximum storage or handling capacity of the facility and normal daily throughput;

(6) Description of the facility, including maps, flow diagrams, and topographical maps;

(7) A complete copy of the SPCC Plan with any amendments;

(8) The cause(s) of such spill, including a failure analysis of system or subsystem in which the failure occurred;

(9) The corrective actions and/or countermeasures taken, including an adequate description of equipment repairs and/or replacements;

(10) Additional preventive measures taken or contemplated to minimize the possibility of recurrence;

(11) Such other information as the Regional Administrator may reasonably require pertinent to the Plan or spill event.

(b) Section 112.4 shall not apply until the expiration of the time permitted for the preparation and implementation of an SPCC Plan pursuant to § 112.3 (a), (b), (c) and (f).

(c) A complete copy of all information provided to the Regional Administrator pursuant to paragraph (a) of this section shall be sent at the same time to the State agency in charge of water pollution control activities in and for the State in which the facility is located. Upon receipt of such information such State agency may conduct a review and make recommendations to the Regional Administrator as to further procedures, methods, equipment and other requirements for equipment necessary to prevent and to contain discharges of oil from such facility.

(d) After review of the SPCC Plan for a facility subject to paragraph (a) of this section, together with all other information submitted by the owner or operator of such facility, and by the State agency under paragraph (c) of this section, the Regional Administrator may require the owner or operator of such facility to amend the SPCC Plan if he finds that the Plan does not meet the requirements of this part or that the amendment of the Plan is necessary to prevent and to contain discharges of oil from such facility.

(e) When the Regional Administrator proposes to require an amendment to the SPCC Plan, he shall notify the facility operator by certified mail addressed to, or by personal delivery to,

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the facility owner or operator, that he proposes to require an amendment to the Plan, and shall specify the terms of such amendment. If the facility owner or operator is a corporation, a copy of such notice shall also be mailed to the registered agent, if any, of such corporation in the State where such facility is located. Within 30 days from receipt of such notice, the facility owner or operator may submit written information, views, and arguments on the amendment. After considering all relevant material presented, the Regional Administrator shall notify the facility owner or operator of any amendment required or shall rescind the notice. The amendment required by the Regional Administrator shall become part of the Plan 30 days after such notice, unless the Regional Administrator, for good cause, shall specify another effective date. The owner or operator of the facility shall implement the amendment of the Plan as soon as possible, but not later than six months after the amendment becomes part of the Plan, unless the Regional Administrator specifies another date.

(f) An owner or operator may appeal a decision made by the Regional Administrator requiring an amendment to an SPCC Plan. The appeal shall be made to the Administrator of the United States Environmental Protection Agency and must be made in writing within 30 days of receipt of the notice from the Regional Administrator requiring the amendment. A complete copy of the appeal must be sent to the Regional Administrator at the time the appeal is made. The appeal shall contain a clear and concise statement of the issues and points of fact in the case. It may also contain additional information from the owner or operator, or from any other person. The Administrator or his designee may request additional information from the owner or operator, or from any other person. The Administrator or his designee shall render a decision within 60 days of receiving the appeal and shall notify the owner or operator of his decision.

[38 FR 34165, Dec. 11, 1973, as amended at 41 FR 12658, Mar. 26, 1976]

§ 112.5 Amendment of Spill Prevention Control and Countermeasure Plans by owners or operators.

(a) Owners or operators of facilities subject to § 112.3 (a), (b) or (c) shall amend the SPCC Plan for such facility in accordance with § 112.7 whenever there is a change in facility design, construction, operation or maintenance which materially affects the facility's potential for the discharge of oil into or upon the navigable waters of the United States or adjoining shore lines. Such amendments shall be fully implemented as soon as possible, but not later than six months after such change occurs.

(b) Notwithstanding compliance with paragraph (a) of this section, owners and operators of facilities subject to § 112.3 (a), (b) or (c) shall complete a review and evaluation of the SPCC Plan at least once every three years from the date such facility becomes subject to this part. As a result of this review and evaluation, the owner or operator shall amend the SPCC Plan within six months of the review to include more effective prevention and control technology if: (1) Such technology will significantly reduce the likelihood of a spill event from the facility, and (2) if such technology has been field-proven at the time of the review.

(c) No amendment to an SPCC Plan shall be effective to satisfy the requirements of this section unless it has been certified by a Professional Engineer in accordance with § 112.3(d).

§ 112.7 Guidelines for the preparation and implementation of a Spill Prevention Control and Countermeasure Plan.

The SPCC Plan shall be a carefully thought-out plan, prepared in accordance with good engineering practices, and which has the full approval of management at a level with authority to commit the necessary resources. If the plan calls for additional facilities or procedures, methods, or equipment not yet fully operational, these items should be discussed in separate paragraphs, and the details of installation and operational start-up should be explained separately. The complete SPCC Plan shall follow the sequence outlined below, and include a discussion of the

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facility's conformance with the appropriate guidelines listed:

(a) A facility which has experienced one or more spill events within twelve months prior to the effective date of this part should include a written description of each such spill, corrective action taken and plans for preventing recurrence.

(b) Where experience indicates a reasonable potential for equipment failure (such as tank overflow, rupture, or leakage), the plan should include a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each major type of failure.

(c) Appropriate containment and/or diversionary structures or equipment to prevent discharged oil from reaching a navigable water course should be provided. One of the following preventive systems or its equivalent should be used as a minimum:

(1) Onshore facilities:

(i) Dikes, berms or retaining walls sufficiently impervious to contain spilled oil;

(ii) Curbing;

(iii) Culverting, gutters or other drainage systems;

(iv) Weirs, booms or other barriers;

(v) Spill diversion ponds;

(vi) Retention ponds;

(vii) Sorbent materials.

(2) Offshore facilities:

(i) Curbing, drip pans;

(ii) Sumps and collection systems.

(d) When it is determined that the installation of structures or equipment listed in §112.7(c) to prevent discharged oil from reaching the navigable waters is not practicable from any onshore or offshore facility, the owner or operator should clearly demonstrate such impracticability and provide the following:

(1) A strong oil spill contingency plan following the provision of 40 CFR part 109.

(2) A written commitment of manpower, equipment and materials required to expeditiously control and remove any harmful quantity of oil discharged.

(e) In addition to the minimal prevention standards listed under §112.7(c), sections of the Plan should include a complete discussion of conformance with the following applicable guidelines, other effective spill prevention and containment procedures (or, if more stringent, with State rules, regulations and guidelines):

(1) *Facility drainage (onshore); (excluding production facilities).* (i) Drainage from diked storage areas should be restrained by valves or other positive means to prevent a spill or other excessive leakage of oil into the drainage system or inplant effluent treatment system, except where plan systems are designed to handle such leakage. Diked areas may be emptied by pumps or ejectors; however, these should be manually activated and the condition of the accumulation should be examined before starting to be sure no oil will be discharged into the water.

(ii) Flapper-type drain valves should not be used to drain diked areas. Valves used for the drainage of diked areas should, as far as practical, be of manual, open-and-closed design. When plant drainage drains directly into water courses and not into wastewater treatment plants, retained storm water should be inspected as provided in paragraphs (e)(2)(iii) (B), (C) and (D) of this section before drainage.

(iii) Plant drainage systems from undiked areas should, if possible, flow into ponds, lagoons or catchment basins, designed to retain oil or return it to the facility. Catchment basins should not be located in areas subject to periodic flooding.

(iv) If plant drainage is not engineered as above, the final discharge of all in-plant ditches should be equipped with a diversion system that could, in the event of an uncontrolled spill, return the oil to the plant.

(v) Where drainage waters are treated in more than one treatment unit, natural hydraulic flow should be used. If pump transfer is needed, two "lift" pumps should be provided, and at least one of the pumps should be permanently installed when such treatment is continuous. In any event, whatever techniques are used facility drainage systems should be adequately engineered to prevent oil from reaching navigable waters in the event of equipment failure or human error at the facility.

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(2) *Bulk storage tanks (onshore); (excluding production facilities).* (i) No tank should be used for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature, etc.

(ii) All bulk storage tank installations should be constructed so that a secondary means of containment is provided for the entire contents of the largest single tank plus sufficient freeboard to allow for precipitation. Diked areas should be sufficiently impervious to contain spilled oil. Dikes, containment curbs, and pits are commonly employed for this purpose, but they may not always be appropriate. An alternative system could consist of a complete drainage trench enclosure arranged so that a spill could terminate and be safely confined in an in-plant catchment basin or holding pond.

(iii) Drainage of rainwater from the diked area into a storm drain or an effluent discharge that empties into an open water course, lake, or pond, and bypassing the in-plant treatment system may be acceptable if:

(A) The bypass valve is normally sealed closed.

(B) Inspection of the run-off rain water ensures compliance with applicable water quality standards and will not cause a harmful discharge as defined in 40 CFR part 110.

(C) The bypass valve is opened, and resealed following drainage under responsible supervision.

(D) Adequate records are kept of such events.

(iv) Buried metallic storage tanks represent a potential for undetected spills. A new buried installation should be protected from corrosion by coatings, cathodic protection or other effective methods compatible with local soil conditions. Such buried tanks should at least be subjected to regular pressure testing.

(v) Partially buried metallic tanks for the storage of oil should be avoided, unless the buried section of the shell is adequately coated, since partial burial in damp earth can cause rapid corrosion of metallic surfaces, especially at the earth/air interface.

(vi) Aboveground tanks should be subject to periodic integrity testing, taking into account tank design (floating roof, etc.) and using such techniques as hydrostatic testing, visual inspection or a system of non-destructive shell thickness testing. Comparison records should be kept where appropriate, and tank supports and foundations should be included in these inspections. In addition, the outside of the tank should frequently be observed by operating personnel for signs of deterioration, leaks which might cause a spill, or accumulation of oil inside diked areas.

(vii) To control leakage through defective internal heating coils, the following factors should be considered and applied, as appropriate.

(A) The steam return or exhaust lines from internal heating coils which discharge into an open water course should be monitored for contamination, or passed through a settling tank, skimmer, or other separation or retention system.

(B) The feasibility of installing an external heating system should also be considered.

(viii) New and old tank installations should, as far as practical, be fail-safe engineered or updated into a fail-safe engineered installation to avoid spills. Consideration should be given to providing one or more of the following devices:

(A) High liquid level alarms with an audible or visual signal at a constantly manned operation or surveillance station; in smaller plants an audible air vent may suffice.

(B) Considering size and complexity of the facility, high liquid level pump cutoff devices set to stop flow at a predetermined tank content level.

(C) Direct audible or code signal communication between the tank gauger and the pumping station.

(D) A fast response system for determining the liquid level of each bulk storage tank such as digital computers, telepulse, or direct vision gauges or their equivalent.

(E) Liquid level sensing devices should be regularly tested to insure proper operation.

(ix) Plant effluents which are discharged into navigable waters should

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have disposal facilities observed frequently enough to detect possible system upsets that could cause an oil spill event.

(x) Visible oil leaks which result in a loss of oil from tank seams, gaskets, rivets and bolts sufficiently large to cause the accumulation of oil in diked areas should be promptly corrected.

(xi) Mobile or portable oil storage tanks (onshore) should be positioned or located so as to prevent spilled oil from reaching navigable waters. A secondary means of containment, such as dikes or catchment basins, should be furnished for the largest single compartment or tank. These facilities should be located where they will not be subject to periodic flooding or washout.

(3) *Facility transfer operations, pumping, and in-plant process (onshore); (excluding production facilities).* (i) Buried piping installations should have a protective wrapping and coating and should be cathodically protected if soil conditions warrant. If a section of buried line is exposed for any reason, it should be carefully examined for deterioration. If corrosion damage is found, additional examination and corrective action should be taken as indicated by the magnitude of the damage. An alternative would be the more frequent use of exposed pipe corridors or galleries.

(ii) When a pipeline is not in service, or in standby service for an extended time the terminal connection at the transfer point should be capped or blank-flanged, and marked as to origin.

(iii) Pipe supports should be properly designed to minimize abrasion and corrosion and allow for expansion and contraction.

(iv) All aboveground valves and pipelines should be subjected to regular examinations by operating personnel at which time the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces should be assessed. In addition, periodic pressure testing may be warranted for piping in areas where facility drainage is such that a failure might lead to a spill event.

(v) Vehicular traffic granted entry into the facility should be warned verbally or by appropriate signs to be sure that the vehicle, because of its size, will not endanger above ground piping.

(4) *Facility tank car and tank truck loading/unloading rack (onshore).* (i) Tank car and tank truck loading/unloading procedures should meet the minimum requirements and regulation established by the Department of Transportation.

(ii) Where rack area drainage does not flow into a catchment basin or treatment facility designed to handle spills, a quick drainage system should be used for tank truck loading and unloading areas. The containment system should be designed to hold at least maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded in the plant.

(iii) An interlocked warning light or physical barrier system, or warning signs, should be provided in loading/unloading areas to prevent vehicular departure before complete disconnect of flexible or fixed transfer lines.

(iv) Prior to filling and departure of any tank car or tank truck, the lowermost drain and all outlets of such vehicles should be closely examined for leakage, and if necessary, tightened, adjusted, or replaced to prevent liquid leakage while in transit.

(5) *Oil production facilities (onshore)*— (i) *Definition.* An onshore production facility may include all wells, flowlines, separation equipment, storage facilities, gathering lines, and auxiliary non-transportation-related equipment and facilities in a single geographical oil or gas field operated by a single operator.

(ii) *Oil production facility (onshore) drainage.* (A) At tank batteries and central treating stations where an accidental discharge of oil would have a reasonable possibility of reaching navigable waters, the dikes or equivalent required under § 112.7(c)(1) should have drains closed and sealed at all times except when rainwater is being drained. Prior to drainage, the diked area should be inspected as provided in paragraphs (e)(2)(iii) (B), (C), and (D) of this section. Accumulated oil on the rainwater should be picked up and returned to storage or disposed of in accordance with approved methods.

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(B) Field drainage ditches, road ditches, and oil traps, sumps or skimmers, if such exist, should be inspected at regularly scheduled intervals for accumulation of oil that may have escaped from small leaks. Any such accumulations should be removed.

(iii) *Oil production facility (onshore) bulk storage tanks.* (A) No tank should be used for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage.

(B) All tank battery and central treating plant installations should be provided with a secondary means of containment for the entire contents of the largest single tank if feasible, or alternate systems such as those outlined in §112.7(c)(1). Drainage from undiked areas should be safely confined in a catchment basin or holding pond.

(C) All tanks containing oil should be visually examined by a competent person for condition and need for maintenance on a scheduled periodic basis. Such examination should include the foundation and supports of tanks that are above the surface of the ground.

(D) New and old tank battery installations should, as far as practical, be fail-safe engineered or updated into a fail-safe engineered installation to prevent spills. Consideration should be given to one or more of the following:

(*1*) Adequate tank capacity to assure that a tank will not overfill should a pumper/gauger be delayed in making his regular rounds.

(*2*) Overflow equalizing lines between tanks so that a full tank can overflow to an adjacent tank.

(*3*) Adequate vacuum protection to prevent tank collapse during a pipeline run.

(*4*) High level sensors to generate and transmit an alarm signal to the computer where facilities are a part of a computer production control system.

(iv) *Facility transfer operations, oil production facility (onshore).* (A) All above ground valves and pipelines should be examined periodically on a scheduled basis for general condition of items such as flange joints, valve glands and bodies, drip pans, pipeline supports, pumping well polish rod stuffing boxes, bleeder and gauge valves.

(B) Salt water (oil field brine) disposal facilities should be examined often, particularly following a sudden change in atmospheric temperature to detect possible system upsets that could cause an oil discharge.

(C) Production facilities should have a program of flowline maintenance to prevent spills from this source. The program should include periodic examinations, corrosion protection, flowline replacement, and adequate records, as appropriate, for the individual facility.

(6) *Oil drilling and workover facilities (onshore).* (i) Mobile drilling or workover equipment should be positioned or located so as to prevent spilled oil from reaching navigable waters.

(ii) Depending on the location, catchment basins or diversion structures may be necessary to intercept and contain spills of fuel, crude oil, or oily drilling fluids.

(iii) Before drilling below any casing string or during workover operations, a blowout prevention (BOP) assembly and well control system should be installed that is capable of controlling any well head pressure that is expected to be encountered while that BOP assembly is on the well. Casing and BOP installations should be in accordance with State regulatory agency requirements.

(7) *Oil drilling, production, or workover facilities (offshore).* (i) Definition: "An oil drilling, production or workover facility (offshore)" may include all drilling or workover equipment, wells, flowlines, gathering lines, platforms, and auxiliary nontransportation-related equipment and facilities in a single geographical oil or gas field operated by a single operator.

(ii) Oil drainage collection equipment should be used to prevent and control small oil spillage around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and allied equipment. Drains on the facility should be controlled and directed toward a central collection sump or equivalent collection system sufficient to prevent discharges of oil into the navigable waters of the United States. Where drains and sumps are not practicable oil contained

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in collection equipment should be removed as often as necessary to prevent overflow.

(iii) For facilities employing a sump system, sump and drains should be adequately sized and a spare pump or equivalent method should be available to remove liquid from the sump and assure that oil does not escape. A regular scheduled preventive maintenance inspection and testing program should be employed to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(iv) In areas where separators and treaters are equipped with dump valves whose predominant mode of failure is in the closed position and pollution risk is high, the facility should be specially equipped to prevent the escape of oil. This could be accomplished by extending the flare line to a diked area if the separator is near shore, equipping it with a high liquid level sensor that will automatically shut-in wells producing to the separator, parallel redundant dump valves, or other feasible alternatives to prevent oil discharges.

(v) Atmospheric storage or surge tanks should be equipped with high liquid level sensing devices or other acceptable alternatives to prevent oil discharges.

(vi) Pressure tanks should be equipped with high and low pressure sensing devices to activate an alarm and/or control the flow or other acceptable alternatives to prevent oil discharges.

(vii) Tanks should be equipped with suitable corrosion protection.

(viii) A written procedure for inspecting and testing pollution prevention equipment and systems should be prepared and maintained at the facility. Such procedures should be included as part of the SPCC Plan.

(ix) Testing and inspection of the pollution prevention equipment and systems at the facility should be conducted by the owner or operator on a scheduled periodic basis commensurate with the complexity, conditions and circumstances of the facility or other appropriate regulations.

(x) Surface and subsurface well shut-in valves and devices in use at the facility should be sufficiently described to determine method of activation or control, e.g., pressure differential, change in fluid or flow conditions, combination of pressure and flow, manual or remote control mechanisms. Detailed records for each well, while not necessarily part of the plan should be kept by the owner or operator.

(xi) Before drilling below any casing string, and during workover operations a blowout preventer (BOP) assembly and well control system should be installed that is capable of controlling any well-head pressure that is expected to be encountered while that BOP assembly is on the well. Casing and BOP installations should be in accordance with State regulatory agency requirements.

(xii) Extraordinary well control measures should be provided should emergency conditions, including fire, loss of control and other abnormal conditions, occur. The degree of control system redundancy should vary with hazard exposure and probable consequences of failure. It is recommended that surface shut-in systems have redundant or "fail close" valving. Subsurface safety valves may not be needed in producing wells that will not flow but should be installed as required by applicable State regulations.

(xiii) In order that there will be no misunderstanding of joint and separate duties and obligations to perform work in a safe and pollution free manner, written instructions should be prepared by the owner or operator for contractors and subcontractors to follow whenever contract activities include servicing a well or systems appurtenant to a well or pressure vessel. Such instructions and procedures should be maintained at the offshore production facility. Under certain circumstances and conditions such contractor activities may require the presence at the facility of an authorized representative of the owner or operator who would intervene when necessary to prevent a spill event.

(xiv) All manifolds (headers) should be equipped with check valves on individual flowlines.

(xv) If the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to

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and including the header valves associated with that individual flowline, the flowline should be equipped with a high pressure sensing device and shut-in valve at the wellhead unless provided with a pressure relief system to prevent over pressuring.

(xvi) All pipelines appurtenant to the facility should be protected from corrosion. Methods used, such as protective coatings or cathodic protection, should be discussed.

(xvii) Sub-marine pipelines appurtenant to the facility should be adequately protected against environmental stresses and other activities such as fishing operations.

(xviii) Sub-marine pipelines appurtenant to the facility should be in good operating condition at all times and inspected on a scheduled periodic basis for failures. Such inspections should be documented and maintained at the facility.

(8) *Inspections and records.* Inspections required by this part should be in accordance with written procedures developed for the facility by the owner or operator. These written procedures and a record of the inspections, signed by the appropriate supervisor or inspector, should be made part of the SPCC Plan and maintained for a period of three years.

(9) *Security (excluding oil production facilities).* (i) All plants handling, processing, and storing oil should be fully fenced, and entrance gates should be locked and/or guarded when the plant is not in production or is unattended.

(ii) The master flow and drain valves and any other valves that will permit direct outward flow of the tank's content to the surface should be securely locked in the closed position when in non-operating or non-standby status.

(iii) The starter control on all oil pumps should be locked in the "off" position or located at a site accessible only to authorized personnel when the pumps are in a non-operating or non-standby status.

(iv) The loading/unloading connections of oil pipelines should be securely capped or blank-flanged when not in service or standby service for an extended time. This security practice should also apply to pipelines that are emptied of liquid content either by draining or by inert gas pressure.

(v) Facility lighting should be commensurate with the type and location of the facility. Consideration should be given to: (A) Discovery of spills occurring during hours of darkness, both by operating personnel, if present, and by non-operating personnel (the general public, local police, etc.) and (B) prevention of spills occurring through acts of vandalism.

(10) *Personnel, training and spill prevention procedures.* (i) Owners or operators are responsible for properly instructing their personnel in the operation and maintenance of equipment to prevent the discharges of oil and applicable pollution control laws, rules and regulations.

(ii) Each applicable facility should have a designated person who is accountable for oil spill prevention and who reports to line management.

(iii) Owners or operators should schedule and conduct spill prevention briefings for their operating personnel at intervals frequent enough to assure adequate understanding of the SPCC Plan for that facility. Such briefings should highlight and describe known spill events or failures, malfunctioning components, and recently developed precautionary measures.

§ 112.20 Facility response plans.

(a) The owner or operator of any non-transportation-related onshore facility that, because of its location, could reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines shall prepare and submit a facility response plan to the Regional Administrator, according to the following provisions:

(1) For the owner or operator of a facility in operation on or before February 18, 1993 who is required to prepare and submit a response plan under 33 U.S.C. 1321(j)(5), the Oil Pollution Act of 1990 (Pub. L. 101–380, 33 U.S.C. 2701 *et seq.*) requires the submission of a response plan that satisfies the requirements of 33 U.S.C. 1321(j)(5) no later than February 18, 1993.

(i) The owner or operator of an existing facility that was in operation on or before February 18, 1993 who submitted

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Attachment B

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OF TRANSPORTATION AND THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY
APPENDIX B TO PART 112—MEMORANDUM OF UNDERSTANDING AMONG THE SECRETARY OF THE INTERIOR, SECRETARY OF TRANSPORTATION, AND ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY
APPENDIX C TO PART 112—SUBSTANTIAL HARM CRITERIA
APPENDIX D TO PART 112—DETERMINATION OF A WORST CASE DISCHARGE PLANNING VOLUME
APPENDIX E TO PART 112—DETERMINATION AND EVALUATION OF REQUIRED RESPONSE RESOURCES FOR FACILITY RESPONSE PLANS
APPENDIX F TO PART 112—FACILITY-SPECIFIC RESPONSE PLAN

AUTHORITY: 33 U.S.C. 1251 *et seq.*; 33 U.S.C. 2720; E.O. 12777 (October 18, 1991), 3 CFR, 1991 Comp., p. 351.

SOURCE: 38 FR 34165, Dec. 11, 1973, unless otherwise noted.

EDITORIAL NOTE: Nomenclature changes to part 112 appear at 65 FR 40798, June 30, 2000.

Subpart A—Applicability, Definitions, and General Requirements for All Facilities and All Types of Oils

SOURCE: 67 FR 47140, July 17, 2002, unless otherwise noted.

§ 112.1 General applicability.

(a)(1) This part establishes procedures, methods, equipment, and other requirements to prevent the discharge of oil from non-transportation-related onshore and offshore facilities into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act).

(2) As used in this part, words in the singular also include the plural and words in the masculine gender also include the feminine and vice versa, as the case may require.

(b) Except as provided in paragraph (d) of this section, this part applies to any owner or operator of a non-transportation-related onshore or offshore facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location, could reasonably be expected to discharge oil in quantities that may be harmful, as described in part 110 of this chapter, into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act) that has oil in:

(1) Any aboveground container;

(2) Any completely buried tank as defined in § 112.2;

(3) Any container that is used for standby storage, for seasonal storage, or for temporary storage, or not otherwise "permanently closed" as defined in § 112.2;

(4) Any "bunkered tank" or "partially buried tank" as defined in § 112.2, or any container in a vault, each of which is considered an aboveground storage container for purposes of this part.

(c) As provided in section 313 of the Clean Water Act (CWA), departments, agencies, and instrumentalities of the Federal government are subject to this part to the same extent as any person.

(d) Except as provided in paragraph (f) of this section, this part does not apply to:

(1) The owner or operator of any facility, equipment, or operation that is not subject to the jurisdiction of the Environmental Protection Agency (EPA) under section 311(j)(1)(C) of the CWA, as follows:

(i) Any onshore or offshore facility, that due to its location, could not reasonably be expected to have a discharge as described in paragraph (b) of this section. This determination must be based solely upon consideration of

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the geographical and location aspects of the facility (such as proximity to navigable waters or adjoining shorelines, land contour, drainage, etc.) and must exclude consideration of manmade features such as dikes, equipment or other structures, which may serve to restrain, hinder, contain, or otherwise prevent a discharge as described in paragraph (b) of this section.

(ii) Any equipment, or operation of a vessel or transportation-related onshore or offshore facility which is subject to the authority and control of the U.S. Department of Transportation, as defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of EPA, dated November 24, 1971 (Appendix A of this part).

(iii) Any equipment, or operation of a vessel or onshore or offshore facility which is subject to the authority and control of the U.S. Department of Transportation or the U.S. Department of the Interior, as defined in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (Appendix B of this part).

(2) Any facility which, although otherwise subject to the jurisdiction of EPA, meets both of the following requirements:

(i) The completely buried storage capacity of the facility is 42,000 gallons or less of oil. For purposes of this exemption, the completely buried storage capacity of a facility excludes the capacity of a completely buried tank, as defined in §112.2, and connected underground piping, underground ancillary equipment, and containment systems, that is currently subject to all of the technical requirements of part 280 of this chapter or all of the technical requirements of a State program approved under part 281 of this chapter. The completely buried storage capacity of a facility also excludes the capacity of a container that is "permanently closed," as defined in §112.2.

(ii) The aggregate aboveground storage capacity of the facility is 1,320 gallons or less of oil. For the purposes of this exemption, only containers with a capacity of 55 gallons or greater are counted. The aggregate aboveground storage capacity of a facility excludes the capacity of a container that is "permanently closed," and the capacity of a "motive power container" as defined in §112.2.

(3) Any offshore oil drilling, production, or workover facility that is subject to the notices and regulations of the Minerals Management Service, as specified in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (Appendix B of this part).

(4) Any completely buried storage tank, as defined in §112.2, and connected underground piping, underground ancillary equipment, and containment systems, at any facility, that is subject to all of the technical requirements of part 280 of this chapter or a State program approved under part 281 of this chapter, except that such a tank must be marked on the facility diagram as provided in §112.7(a)(3), if the facility is otherwise subject to this part.

(5) Any container with a storage capacity of less than 55 gallons of oil.

(6) Any facility or part thereof used exclusively for wastewater treatment and not used to satisfy any requirement of this part. The production, recovery, or recycling of oil is not wastewater treatment for purposes of this paragraph.

(7) Any "motive power container," as defined in §112.2. The transfer of fuel or other oil into a motive power container at an otherwise regulated facility is not eligible for this exemption.

(e) This part establishes requirements for the preparation and implementation of Spill Prevention, Control, and Countermeasure (SPCC) Plans. SPCC Plans are designed to complement existing laws, regulations, rules, standards, policies, and procedures pertaining to safety standards, fire prevention, and pollution prevention rules. The purpose of an SPCC Plan is to form a comprehensive Federal/State spill prevention program that minimizes the potential for discharges. The SPCC Plan must address all relevant spill prevention, control, and countermeasures necessary at the specific facility. Compliance with this

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part does not in any way relieve the owner or operator of an onshore or an offshore facility from compliance with other Federal, State, or local laws.

(f) Notwithstanding paragraph (d) of this section, the Regional Administrator may require that the owner or operator of any facility subject to the jurisdiction of EPA under section 311(j) of the CWA prepare and implement an SPCC Plan, or any applicable part, to carry out the purposes of the CWA.

(1) Following a preliminary determination, the Regional Administrator must provide a written notice to the owner or operator stating the reasons why he must prepare an SPCC Plan, or applicable part. The Regional Administrator must send such notice to the owner or operator by certified mail or by personal delivery. If the owner or operator is a corporation, the Regional Administrator must also mail a copy of such notice to the registered agent, if any and if known, of the corporation in the State where the facility is located.

(2) Within 30 days of receipt of such written notice, the owner or operator may provide information and data and may consult with the Agency about the need to prepare an SPCC Plan, or applicable part.

(3) Within 30 days following the time under paragraph (b)(2) of this section within which the owner or operator may provide information and data and consult with the Agency about the need to prepare an SPCC Plan, or applicable part, the Regional Administrator must make a final determination regarding whether the owner or operator is required to prepare and implement an SPCC Plan, or applicable part. The Regional Administrator must send the final determination to the owner or operator by certified mail or by personal delivery. If the owner or operator is a corporation, the Regional Administrator must also mail a copy of the final determination to the registered agent, if any and if known, of the corporation in the State where the facility is located.

(4) If the Regional Administrator makes a final determination that an SPCC Plan, or applicable part, is necessary, the owner or operator must prepare the Plan, or applicable part, within six months of that final determination and implement the Plan, or applicable part, as soon as possible, but not later than one year after the Regional Administrator has made a final determination.

(5) The owner or operator may appeal a final determination made by the Regional Administrator requiring preparation and implementation of an SPCC Plan, or applicable part, under this paragraph. The owner or operator must make the appeal to the Administrator of EPA within 30 days of receipt of the final determination under paragraph (b)(3) of this section from the Regional Administrator requiring preparation and/or implementation of an SPCC Plan, or applicable part. The owner or operator must send a complete copy of the appeal to the Regional Administrator at the time he makes the appeal to the Administrator. The appeal must contain a clear and concise statement of the issues and points of fact in the case. In the appeal, the owner or operator may also provide additional information. The additional information may be from any person. The Administrator may request additional information from the owner or operator. The Administrator must render a decision within 60 days of receiving the appeal or additional information submitted by the owner or operator and must serve the owner or operator with the decision made in the appeal in the manner described in paragraph (f)(1) of this section.

[67 FR 47140, July 17, 2002, as amended at 71 FR 77290, Dec. 26, 2006]

§ 112.2 Definitions.

For the purposes of this part:

Adverse weather means weather conditions that make it difficult for response equipment and personnel to clean up or remove spilled oil, and that must be considered when identifying response systems and equipment in a response plan for the applicable operating environment. Factors to consider include significant wave height as specified in Appendix E to this part (as appropriate), ice conditions, temperatures, weather-related visibility, and currents within the area in which the systems or equipment is intended to function.

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Alteration means any work on a container involving cutting, burning, welding, or heating operations that changes the physical dimensions or configuration of the container.

Animal fat means a non-petroleum oil, fat, or grease of animal, fish, or marine mammal origin.

Breakout tank means a container used to relieve surges in an oil pipeline system or to receive and store oil transported by a pipeline for reinjection and continued transportation by pipeline.

Bulk storage container means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container.

Bunkered tank means a container constructed or placed in the ground by cutting the earth and re-covering the container in a manner that breaks the surrounding natural grade, or that lies above grade, and is covered with earth, sand, gravel, asphalt, or other material. A bunkered tank is considered an aboveground storage container for purposes of this part.

Completely buried tank means any container completely below grade and covered with earth, sand, gravel, asphalt, or other material. Containers in vaults, bunkered tanks, or partially buried tanks are considered aboveground storage containers for purposes of this part.

Complex means a facility possessing a combination of transportation-related and non-transportation-related components that is subject to the jurisdiction of more than one Federal agency under section 311(j) of the CWA.

Contiguous zone means the zone established by the United States under Article 24 of the Convention of the Territorial Sea and Contiguous Zone, that is contiguous to the territorial sea and that extends nine miles seaward from the outer limit of the territorial area.

Contract or other approved means means:

(1) A written contractual agreement with an oil spill removal organization that identifies and ensures the availability of the necessary personnel and equipment within appropriate response times; and/or

(2) A written certification by the owner or operator that the necessary personnel and equipment resources, owned or operated by the facility owner or operator, are available to respond to a discharge within appropriate response times; and/or

(3) Active membership in a local or regional oil spill removal organization that has identified and ensures adequate access through such membership to necessary personnel and equipment to respond to a discharge within appropriate response times in the specified geographic area; and/or

(4) Any other specific arrangement approved by the Regional Administrator upon request of the owner or operator.

Discharge includes, but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil, but excludes discharges in compliance with a permit under section 402 of the CWA; discharges resulting from circumstances identified, reviewed, and made a part of the public record with respect to a permit issued or modified under section 402 of the CWA, and subject to a condition in such permit; or continuous or anticipated intermittent discharges from a point source, identified in a permit or permit application under section 402 of the CWA, that are caused by events occurring within the scope of relevant operating or treatment systems. For purposes of this part, the term discharge shall not include any discharge of oil that is authorized by a permit issued under section 13 of the River and Harbor Act of 1899 (33 U.S.C. 407).

Facility means any mobile or fixed, onshore or offshore building, structure, installation, equipment, pipe, or pipeline (other than a vessel or a public vessel) used in oil well drilling operations, oil production, oil refining, oil storage, oil gathering, oil processing, oil transfer, oil distribution, and waste treatment, or in which oil is used, as described in Appendix A to this part. The boundaries of a facility depend on several site-specific factors, including, but not limited to, the ownership or operation of buildings, structures, and

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equipment on the same site and the types of activity at the site.

Farm means a facility on a tract of land devoted to the production of crops or raising of animals, including fish, which produced and sold, or normally would have produced and sold, $1,000 or more of agricultural products during a year.

Fish and wildlife and sensitive environments means areas that may be identified by their legal designation or by evaluations of Area Committees (for planning) or members of the Federal On-Scene Coordinator's spill response structure (during responses). These areas may include wetlands, National and State parks, critical habitats for endangered or threatened species, wilderness and natural resource areas, marine sanctuaries and estuarine reserves, conservation areas, preserves, wildlife areas, wildlife refuges, wild and scenic rivers, recreational areas, national forests, Federal and State lands that are research national areas, heritage program areas, land trust areas, and historical and archaeological sites and parks. These areas may also include unique habitats such as aquaculture sites and agricultural surface water intakes, bird nesting areas, critical biological resource areas, designated migratory routes, and designated seasonal habitats.

Injury means a measurable adverse change, either long- or short-term, in the chemical or physical quality or the viability of a natural resource resulting either directly or indirectly from exposure to a discharge, or exposure to a product of reactions resulting from a discharge.

Maximum extent practicable means within the limitations used to determine oil spill planning resources and response times for on-water recovery, shoreline protection, and cleanup for worst case discharges from onshore non-transportation-related facilities in adverse weather. It includes the planned capability to respond to a worst case discharge in adverse weather, as contained in a response plan that meets the requirements in §112.20 or in a specific plan approved by the Regional Administrator.

Mobile refueler means a bulk storage container onboard a vehicle or towed, that is designed or used solely to store and transport fuel for transfer into or from an aircraft, motor vehicle, locomotive, vessel, ground service equipment, or other oil storage container.

Motive power container means any onboard bulk storage container used primarily to power the movement of a motor vehicle, or ancillary onboard oil-filled operational equipment. An onboard bulk storage container which is used to store or transfer oil for further distribution is not a motive power container. The definition of motive power container does not include oil drilling or workover equipment, including rigs.

Navigable waters means the waters of the United States, including the territorial seas.

(1) The term includes:

(i) All waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters subject to the ebb and flow of the tide;

(ii) All interstate waters, including interstate wetlands;

(iii) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, wetlands, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation, or destruction of which could affect interstate or foreign commerce including any such waters:

(A) That are or could be used by interstate or foreign travelers for recreational or other purposes; or

(B) From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or,

(C) That are or could be used for industrial purposes by industries in interstate commerce;

(iv) All impoundments of waters otherwise defined as waters of the United States under this section;

(v) Tributaries of waters identified in paragraphs (1)(i) through (iv) of this definition;

(vi) The territorial sea; and

(vii) Wetlands adjacent to waters (other than waters that are themselves wetlands) identified in paragraph (1) of this definition.

(2) Waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of the

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CWA (other than cooling ponds which also meet the criteria of this definition) are not waters of the United States. Navigable waters do not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other Federal agency, for the purposes of the CWA, the final authority regarding CWA jurisdiction remains with EPA.

Non-petroleum oil means oil of any kind that is not petroleum-based, including but not limited to: Fats, oils, and greases of animal, fish, or marine mammal origin; and vegetable oils, including oils from seeds, nuts, fruits, and kernels.

Offshore facility means any facility of any kind (other than a vessel or public vessel) located in, on, or under any of the navigable waters of the United States, and any facility of any kind that is subject to the jurisdiction of the United States and is located in, on, or under any other waters.

Oil means oil of any kind or in any form, including, but not limited to: fats, oils, or greases of animal, fish, or marine mammal origin; vegetable oils, including oils from seeds, nuts, fruits, or kernels; and, other oils and greases, including petroleum, fuel oil, sludge, synthetic oils, mineral oils, oil refuse, or oil mixed with wastes other than dredged spoil.

Oil-filled operational equipment means equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process). Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (*e.g.*, those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, and other systems containing oil solely to enable the operation of the device.

Oil Spill Removal Organization means an entity that provides oil spill response resources, and includes any for-profit or not-for-profit contractor, cooperative, or in-house response resources that have been established in a geographic area to provide required response resources.

Onshore facility means any facility of any kind located in, on, or under any land within the United States, other than submerged lands.

Owner or operator means any person owning or operating an onshore facility or an offshore facility, and in the case of any abandoned offshore facility, the person who owned or operated or maintained the facility immediately prior to such abandonment.

Partially buried tank means a storage container that is partially inserted or constructed in the ground, but not entirely below grade, and not completely covered with earth, sand, gravel, asphalt, or other material. A partially buried tank is considered an aboveground storage container for purposes of this part.

Permanently closed means any container or facility for which:

(1) All liquid and sludge has been removed from each container and connecting line; and

(2) All connecting lines and piping have been disconnected from the container and blanked off, all valves (except for ventilation valves) have been closed and locked, and conspicuous signs have been posted on each container stating that it is a permanently closed container and noting the date of closure.

Person includes an individual, firm, corporation, association, or partnership.

Petroleum oil means petroleum in any form, including but not limited to crude oil, fuel oil, mineral oil, sludge, oil refuse, and refined products.

Production facility means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil, or associated storage or measurement,

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and located in a single geographical oil or gas field operated by a single operator.

Regional Administrator means the Regional Administrator of the Environmental Protection Agency, in and for the Region in which the facility is located.

Repair means any work necessary to maintain or restore a container to a condition suitable for safe operation, other than that necessary for ordinary, day-to-day maintenance to maintain the functional integrity of the container and that does not weaken the container.

Spill Prevention, Control, and Countermeasure Plan; SPCC Plan, or Plan means the document required by §112.3 that details the equipment, workforce, procedures, and steps to prevent, control, and provide adequate countermeasures to a discharge.

Storage capacity of a container means the shell capacity of the container.

Transportation-related and non-transportation-related, as applied to an onshore or offshore facility, are defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, dated November 24, 1971, (Appendix A of this part).

United States means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Commonwealth of the Northern Mariana Islands, Guam, American Samoa, the U.S. Virgin Islands, and the Pacific Island Governments.

Vegetable oil means a non-petroleum oil or fat of vegetable origin, including but not limited to oils and fats derived from plant seeds, nuts, fruits, and kernels.

Vessel means every description of watercraft or other artificial contrivance used, or capable of being used, as a means of transportation on water, other than a public vessel.

Wetlands means those areas that are inundated or saturated by surface or groundwater at a frequency or duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include playa lakes, swamps, marshes, bogs, and similar areas such as sloughs, prairie potholes, wet meadows, prairie river overflows, mudflats, and natural ponds.

Worst case discharge for an onshore non-transportation-related facility means the largest foreseeable discharge in adverse weather conditions as determined using the worksheets in Appendix D to this part.

[67 FR 47140, July 17, 2002, as amended at 71 FR 77290, Dec. 26, 2006]

§112.3 Requirement to prepare and implement a Spill Prevention, Control, and Countermeasure Plan.

The owner or operator of an onshore or offshore facility subject to this section must prepare a Spill Prevention, Control, and Countermeasure Plan (hereafter "SPCC Plan" or "Plan)," in writing, and in accordance with §112.7, and any other applicable section of this part.

(a)(1) If your onshore or offshore facility was in operation on or before August 16, 2002, you must maintain your Plan, but most amend it, if necessary to ensure compliance with this part, and implement the Plan no later than July 1, 2009. If your onshore or offshore facility becomes operational after August 16, 2002, through July 1, 2009, and could reasonably be expected to have a discharge as described in §112.1(b), you must prepare and implement a Plan on or before July 1, 2009.

(2) If your onshore facility is a farm as defined in §112.2, the compliance date described in paragraph (a)(1) of this section is delayed until the effective date of a rule establishing SPCC requirements specifically for farms or otherwise establishes dates by which farms must comply with the provisions of this part.

(b)(1) If you are the owner or operator of an onshore or offshore facility that becomes operational after July 1, 2009, and could reasonably be expected to have a discharge as described in §112.1(b), you must prepare and implement a Plan before you begin operations.

(2) If your onshore facility meets the definition of farm in §112.2, the compliance date described in paragraph (b)(1) of this section is delayed until the effective date of a rule establishing

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SPCC requirements specifically for farms or otherwise establishes dates by which farms must comply with the provisions of this part.

(c) If you are the owner or operator of an onshore or offshore mobile facility, such as an onshore drilling or workover rig, barge mounted offshore drilling or workover rig, or portable fueling facility, you must prepare, implement, and maintain a facility Plan as required by this section. You must maintain your Plan, but must amend and implement it, if necessary to ensure compliance with this part, on or before July 1, 2009. If your onshore or offshore mobile facility becomes operational after July 1, 2009, and could reasonably be expected to have a discharge as described in §112.1(b), you must prepare and implement a Plan before you begin operations. This provision does not require that you prepare a new Plan each time you move the facility to a new site. The Plan may be a general Plan. When you move the mobile or portable facility, you must locate and install it using the discharge prevention practices outlined in the Plan for the facility. The Plan is applicable only while the facility is in a fixed (non-transportation) operating mode.

(d) Except as provided in §112.6, a licensed Professional Engineer must review and certify a Plan for it to be effective to satisfy the requirements of this part.

(1) By means of this certification the Professional Engineer attests:

(i) That he is familiar with the requirements of this part ;

(ii) That he or his agent has visited and examined the facility;

(iii) That the Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part;

(iv) That procedures for required inspections and testing have been established; and

(v) That the Plan is adequate for the facility.

(2) Such certification shall in no way relieve the owner or operator of a facility of his duty to prepare and fully implement such Plan in accordance with the requirements of this part.

(e) If you are the owner or operator of a facility for which a Plan is required under this section, you must:

(1) Maintain a complete copy of the Plan at the facility if the facility is normally attended at least four hours per day, or at the nearest field office if the facility is not so attended, and

(2) Have the Plan available to the Regional Administrator for on-site review during normal working hours.

(f) *Extension of time.* (1) The Regional Administrator may authorize an extension of time for the preparation and full implementation of a Plan, or any amendment thereto, beyond the time permitted for the preparation, implementation, or amendment of a Plan under this part, when he finds that the owner or operator of a facility subject to this section, cannot fully comply with the requirements as a result of either nonavailability of qualified personnel, or delays in construction or equipment delivery beyond the control and without the fault of such owner or operator or his agents or employees.

(2) If you are an owner or operator seeking an extension of time under paragraph (f)(1) of this section, you may submit a written extension request to the Regional Administrator. Your request must include:

(i) A full explanation of the cause for any such delay and the specific aspects of the Plan affected by the delay;

(ii) A full discussion of actions being taken or contemplated to minimize or mitigate such delay; and

(iii) A proposed time schedule for the implementation of any corrective actions being taken or contemplated, including interim dates for completion of tests or studies, installation and operation of any necessary equipment, or other preventive measures. In addition you may present additional oral or written statements in support of your extension request.

(3) The submission of a written extension request under paragraph (f)(2) of this section does not relieve you of your obligation to comply with the requirements of this part. The Regional Administrator may request a copy of your Plan to evaluate the extension request. When the Regional Administrator authorizes an extension of time

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for particular equipment or other specific aspects of the Plan, such extension does not affect your obligation to comply with the requirements related to other equipment or other specific aspects of the Plan for which the Regional Administrator has not expressly authorized an extension.

(g) *Qualified Facilities.* The owner or operator of a qualified facility as defined in this subparagraph may self-certify his or her facility's Plan, as provided in §112.6. A qualified facility is one that:

(1) Has an aggregate aboveground storage capacity of 10,000 gallons or less; and

(2) Has had no single discharge as described in §112.1(b) exceeding 1,000 U.S. gallons or no two discharges as described in §112.1(b) each exceeding 42 U.S. gallons within any twelve month period in the three years prior to the SPCC Plan self-certification date, or since becoming subject to this part if the facility has been in operation for less than three years (other than discharges as described in §112.1(b) that are the result of natural disasters, acts of war, or terrorism).

[67 FR 47140, July 17, 2002, as amended at 68 FR 1351, Jan. 9, 2003; 68 FR 18894, Apr. 17, 2003; 69 FR 48798, Aug. 11, 2004; 71 FR 8466, Feb. 17, 2006; 71 FR 77290, Dec. 26, 2006; 72 FR 27447, May 16, 2007]

§112.4 Amendment of Spill Prevention, Control, and Countermeasure Plan by Regional Administrator.

If you are the owner or operator of a facility subject to this part, you must:

(a) Notwithstanding compliance with §112.3, whenever your facility has discharged more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b), or discharged more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b), occurring within any twelve month period, submit the following information to the Regional Administrator within 60 days from the time the facility becomes subject to this section:

(1) Name of the facility;

(2) Your name;

(3) Location of the facility;

(4) Maximum storage or handling capacity of the facility and normal daily throughput;

(5) Corrective action and countermeasures you have taken, including a description of equipment repairs and replacements;

(6) An adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary;

(7) The cause of such discharge as described in §112.1(b), including a failure analysis of the system or subsystem in which the failure occurred;

(8) Additional preventive measures you have taken or contemplated to minimize the possibility of recurrence; and

(9) Such other information as the Regional Administrator may reasonably require pertinent to the Plan or discharge.

(b) Take no action under this section until it applies to your facility. This section does not apply until the expiration of the time permitted for the initial preparation and implementation of the Plan under §112.3, but not including any amendments to the Plan.

(c) Send to the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located a complete copy of all information you provided to the Regional Administrator under paragraph (a) of this section. Upon receipt of the information such State agency or agencies may conduct a review and make recommendations to the Regional Administrator as to further procedures, methods, equipment, and other requirements necessary to prevent and to contain discharges from your facility.

(d) Amend your Plan, if after review by the Regional Administrator of the information you submit under paragraph (a) of this section, or submission of information to EPA by the State agency under paragraph (c) of this section, or after on-site review of your Plan, the Regional Administrator requires that you do so. The Regional Administrator may require you to amend your Plan if he finds that it does not meet the requirements of this part or that amendment is necessary to prevent and contain discharges from your facility.

(e) Act in accordance with this paragraph when the Regional Administrator proposes by certified mail or by personal delivery that you amend your

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SPCC Plan. If the owner or operator is a corporation, he must also notify by mail the registered agent of such corporation, if any and if known, in the State in which the facility is located. The Regional Administrator must specify the terms of such proposed amendment. Within 30 days from receipt of such notice, you may submit written information, views, and arguments on the proposed amendment. After considering all relevant material presented, the Regional Administrator must either notify you of any amendment required or rescind the notice. You must amend your Plan as required within 30 days after such notice, unless the Regional Administrator, for good cause, specifies another effective date. You must implement the amended Plan as soon as possible, but not later than six months after you amend your Plan, unless the Regional Administrator specifies another date.

(f) If you appeal a decision made by the Regional Administrator requiring an amendment to an SPCC Plan, send the appeal to the EPA Administrator in writing within 30 days of receipt of the notice from the Regional Administrator requiring the amendment under paragraph (e) of this section. You must send a complete copy of the appeal to the Regional Administrator at the time you make the appeal. The appeal must contain a clear and concise statement of the issues and points of fact in the case. It may also contain additional information from you, or from any other person. The EPA Administrator may request additional information from you, or from any other person. The EPA Administrator must render a decision within 60 days of receiving the appeal and must notify you of his decision.

§ 112.5 Amendment of Spill Prevention, Control, and Countermeasure Plan by owners or operators.

If you are the owner or operator of a facility subject to this part, you must:

(a) Amend the SPCC Plan for your facility in accordance with the general requirements in § 112.7, and with any specific section of this part applicable to your facility, when there is a change in the facility design, construction, operation, or maintenance that materially affects its potential for a discharge as described in § 112.1(b). Examples of changes that may require amendment of the Plan include, but are not limited to: commissioning or decommissioning containers; replacement, reconstruction, or movement of containers; reconstruction, replacement, or installation of piping systems; construction or demolition that might alter secondary containment structures; changes of product or service; or revision of standard operation or maintenance procedures at a facility. An amendment made under this section must be prepared within six months, and implemented as soon as possible, but not later than six months following preparation of the amendment.

(b) Notwithstanding compliance with paragraph (a) of this section, complete a review and evaluation of the SPCC Plan at least once every five years from the date your facility becomes subject to this part; or, if your facility was in operation on or before August 16, 2002, five years from the date your last review was required under this part. As a result of this review and evaluation, you must amend your SPCC Plan within six months of the review to include more effective prevention and control technology if the technology has been field-proven at the time of the review and will significantly reduce the likelihood of a discharge as described in § 112.1(b) from the facility. You must implement any amendment as soon as possible, but not later than six months following preparation of any amendment. You must document your completion of the review and evaluation, and must sign a statement as to whether you will amend the Plan, either at the beginning or end of the Plan or in a log or an appendix to the Plan. The following words will suffice, "I have completed review and evaluation of the SPCC Plan for (name of facility) on (date), and will (will not) amend the Plan as a result."

(c) Except as provided in § 112.6, have a Professional Engineer certify any technical amendments to your Plan in accordance with § 112.3(d).

[67 FR 47140, July 17, 2002, as amended at 71 FR 77291, Dec. 26, 2006]

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§ 112.6 Qualified Facility Plan Requirements.

(a) *Preparation and Self-certification of Plan.* If you are the owner or operator of a facility that meets the qualified facility qualification criteria in §112.3(g), you may choose to self-certify your Plan. You must certify in the Plan that:

(1) You are familiar with the requirements of this part;

(2) You have visited and examined the facility;

(3) The Plan has been prepared in accordance with accepted and sound industry practices and standards, and with the requirements of this part;

(4) Procedures for required inspections and testing have been established;

(5) The Plan is being fully implemented;

(6) The facility meets the qualification criteria set forth under §112.3(g);

(7) The Plan does not deviate from any requirement of this part as allowed by §§112.7(a)(2) and 112.7(d), except as provided in paragraph (c) of this section; and

(8) The Plan and individual(s) responsible for implementing the Plan have the full approval of management and the facility owner or operator has committed the necessary resources to fully implement the Plan.

(b) *Self-certification of Technical Amendments.* If you self-certify your Plan pursuant to paragraph (a) of this section, you must certify any technical amendments to your Plan in accordance with paragraph (a) of this section when there is a change in the facility design, construction, operation, or maintenance that affects its potential for a discharge as described in §112.1(b) except:

(1) If a Professional Engineer certified a portion of your Plan in accordance with paragraph (d) of this section, and the technical amendment affects this portion of the Plan, you must have the amended provisions of your Plan certified by a Professional Engineer in accordance with §112.6(d)(2).

(2) If the change is such that the facility no longer meets the qualifying criteria in §112.3(g) because it exceeds 10,000 gallons in aggregate aboveground storage capacity, you must prepare a Plan in accordance with the general Plan requirements in §112.7 and the applicable requirements in subparts B and C, including having the Plan certified by a Professional Engineer as required under §112.3(d).

(c) *Applicable Requirements.* Except as provided in this subparagraph, your self-certified SPCC Plan must comply with §112.7 and the applicable requirements in subparts B and C of this part:

(1) *Environmental Equivalence.* Your Plan may not include alternate methods which provide environmental equivalence pursuant to §112.7(a)(2), unless each alternate method has been reviewed and certified in writing by a Professional Engineer, as provided in paragraph (d) of this section.

(2) *Impracticability.* Your Plan may not include any determinations that secondary containment is impracticable and provisions in lieu of secondary containment pursuant to §112.7(d), unless each such determination and alternative provision has been reviewed and certified in writing by a Professional Engineer, as provided in paragraph (d) of this section.

(3) *Security (excluding oil production facilities).* You must either:

(i) Comply with the requirements under §112.7(g); or

(ii) Describe in your Plan how you secure and control access to the oil handling, processing and storage areas; secure master flow and drain valves; prevent unauthorized access to starter controls on oil pumps; secure out-of-service and loading/unloading connections of oil pipelines; address the appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges.

(4) *Bulk Storage Container Inspections.* You must either:

(i) Comply with the requirements under §112.8(c)(6) or §112.12(c)(6), as applicable; or

(ii) Test/inspect each aboveground container for integrity on a regular schedule and whenever material repairs are made. You must determine, in accordance with industry standards, the appropriate qualifications for personnel performing tests and inspections, the frequency and type of testing and inspections which take into account container size, configuration,

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and design (such as containers that are: shop built, skid-mounted, elevated, equipped with a liner, double walled, or partially buried). Examples of these integrity tests include, but are not limited to: visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other systems of non-destructive testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements of this paragraph.

(d) *Professional Engineer Certification of Portions of a Qualified Facility's Self-certified Plan.* As described in paragraph (c) of this section, the facility owner or operator may not self-certify alternative measures allowed under §112.7(a)(2) or (d), that are included in the facility's Plan. Such measures must be reviewed and certified, in writing, by a licensed Professional Engineer as follows:

(1) For each alternative measure allowed under §112.7(a)(2), the Plan must be accompanied by a written statement by a Professional Engineer that states the reason for nonconformance and describes the alternative method and how it provides equivalent environmental protection in accordance with §112.7(a)(2). For each determination of impracticability of secondary containment pursuant to §112.7(d), the Plan must clearly explain why secondary containment measures are not practicable at this facility and provide the alternative measures required in §112.7(d) in lieu of secondary containment.

(2) By certifying each measure allowed under §112.7(a)(2) and (d), the Professional Engineer attests:

(i) That he is familiar with the requirements of this part;

(ii) That he or his agent has visited and examined the facility; and

(iii) That the alternative method of environmental equivalence in accordance with §112.7(a)(2) or the determination of impracticability and alternative measures in accordance with §112.7(d) is consistent with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part.

(3) The review and certification by the Professional Engineer under this paragraph is limited to the alternative method which achieves equivalent environmental protection pursuant to §112.7(a)(2) or to the impracticability determination and measures in lieu of secondary containment pursuant to §112.7(d).

[71 FR 77291, Dec. 26, 2006]

§112.7 General requirements for Spill Prevention, Control, and Countermeasure Plans.

If you are the owner or operator of a facility subject to this part you must prepare a Plan in accordance with good engineering practices. The Plan must have the full approval of management at a level of authority to commit the necessary resources to fully implement the Plan. You must prepare the Plan in writing. If you do not follow the sequence specified in this section for the Plan, you must prepare an equivalent Plan acceptable to the Regional Administrator that meets all of the applicable requirements listed in this part, and you must supplement it with a section cross-referencing the location of requirements listed in this part and the equivalent requirements in the other prevention plan. If the Plan calls for additional facilities or procedures, methods, or equipment not yet fully operational, you must discuss these items in separate paragraphs, and must explain separately the details of installation and operational start-up. As detailed elsewhere in this section, you must also:

(a)(1) Include a discussion of your facility's conformance with the requirements listed in this part.

(2) Comply with all applicable requirements listed in this part. Except as provided in §112.6, your Plan may deviate from the requirements in paragraphs (g), (h)(2) and (3), and (l) of this section and the requirements in subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§112.8(c)(2), 112.8(c)(11),

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112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11), where applicable to a specific facility, if you provide equivalent environmental protection by some other means of spill prevention, control, or countermeasure. Where your Plan does not conform to the applicable requirements in paragraphs (g), (h)(2) and (3), and (i) of this section, or the requirements of subparts B and C of this part, except the secondary containment requirements in paragraph (c) and (h)(1) of this section, and §§ 112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11), you must state the reasons for nonconformance in your Plan and describe in detail alternate methods and how you will achieve equivalent environmental protection. If the Regional Administrator determines that the measures described in your Plan do not provide equivalent environmental protection, he may require that you amend your Plan, following the procedures in § 112.4(d) and (e).

(3) Describe in your Plan the physical layout of the facility and include a facility diagram, which must mark the location and contents of each container. The facility diagram must include completely buried tanks that are otherwise exempted from the requirements of this part under § 112.1(d)(4). The facility diagram must also include all transfer stations and connecting pipes. You must also address in your Plan:

(i) The type of oil in each container and its storage capacity;

(ii) Discharge prevention measures including procedures for routine handling of products (loading, unloading, and facility transfers, etc.);

(iii) Discharge or drainage controls such as secondary containment around containers and other structures, equipment, and procedures for the control of a discharge;

(iv) Countermeasures for discharge discovery, response, and cleanup (both the facility's capability and those that might be required of a contractor);

(v) Methods of disposal of recovered materials in accordance with applicable legal requirements; and

(vi) Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with whom you have an agreement for response, and all appropriate Federal, State, and local agencies who must be contacted in case of a discharge as described in § 112.1(b).

(4) Unless you have submitted a response plan under § 112.20, provide information and procedures in your Plan to enable a person reporting a discharge as described in § 112.1(b) to relate information on the exact address or location and phone number of the facility; the date and time of the discharge, the type of material discharged; estimates of the total quantity discharged; estimates of the quantity discharged as described in § 112.1(b); the source of the discharge; a description of all affected media; the cause of the discharge; any damages or injuries caused by the discharge; actions being used to stop, remove, and mitigate the effects of the discharge; whether an evacuation may be needed; and, the names of individuals and/or organizations who have also been contacted.

(5) Unless you have submitted a response plan under § 112.20, organize portions of the Plan describing procedures you will use when a discharge occurs in a way that will make them readily usable in an emergency, and include appropriate supporting material as appendices.

(b) Where experience indicates a reasonable potential for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of a discharge), include in your Plan a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure.

(c) Provide appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in § 112.1(b), except as provided in paragraph (k) of this section for qualified oil-filled operational equipment. The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank or pipe, will not escape the containment system before cleanup

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occurs. At a minimum, you must use one of the following prevention systems or its equivalent:

(1) For onshore facilities:

(i) Dikes, berms, or retaining walls sufficiently impervious to contain oil;

(ii) Curbing;

(iii) Culverting, gutters, or other drainage systems;

(iv) Weirs, booms, or other barriers;

(v) Spill diversion ponds;

(vi) Retention ponds; or

(vii) Sorbent materials.

(2) For offshore facilities:

(i) Curbing or drip pans; or

(ii) Sumps and collection systems.

(d) Provided your Plan is certified by a licensed Professional Engineer under §112.3(d), or, in the case of a qualified facility that meets the criteria in §112.3(g), the relevant sections of your Plan are certified by a licensed Professional Engineer under §112.6(d), if you determine that the installation of any of the structures or pieces of equipment listed in paragraphs (c) and (h)(1) of this section, and §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11) to prevent a discharge as described in §112.1(b) from any onshore or offshore facility is not practicable, you must clearly explain in your Plan why such measures are not practicable; for bulk storage containers, conduct both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; and, unless you have submitted a response plan under §112.20, provide in your Plan the following:

(1) An oil spill contingency plan following the provisions of part 109 of this chapter.

(2) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

(e) *Inspections, tests, and records.* Conduct inspections and tests required by this part in accordance with written procedures that you or the certifying engineer develop for the facility. You must keep these written procedures and a record of the inspections and tests, signed by the appropriate supervisor or inspector, with the SPCC Plan for a period of three years. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

(f) *Personnel, training, and discharge prevention procedures.* (1) At a minimum, train your oil-handling personnel in the operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and, the contents of the facility SPCC Plan.

(2) Designate a person at each applicable facility who is accountable for discharge prevention and who reports to facility management.

(3) Schedule and conduct discharge prevention briefings for your oil-handling personnel at least once a year to assure adequate understanding of the SPCC Plan for that facility. Such briefings must highlight and describe known discharges as described in §112.1(b) or failures, malfunctioning components, and any recently developed precautionary measures.

(g) *Security (excluding oil production facilities).* (1) Fully fence each facility handling, processing, or storing oil, and lock and/or guard entrance gates when the facility is not in production or is unattended.

(2) Ensure that the master flow and drain valves and any other valves permitting direct outward flow of the container's contents to the surface have adequate security measures so that they remain in the closed position when in non-operating or non-standby status.

(3) Lock the starter control on each oil pump in the "off" position and locate it at a site accessible only to authorized personnel when the pump is in a non-operating or non-standby status.

(4) Securely cap or blank-flange the loading/unloading connections of oil pipelines or facility piping when not in service or when in standby service for an extended time. This security practice also applies to piping that is emptied of liquid content either by draining or by inert gas pressure.

(5) Provide facility lighting commensurate with the type and location of the facility that will assist in the:

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(i) Discovery of discharges occurring during hours of darkness, both by operating personnel, if present, and by non-operating personnel (the general public, local police, etc.); and

(ii) Prevention of discharges occurring through acts of vandalism.

(h) *Facility tank car and tank truck loading/unloading rack (excluding offshore facilities).* (1) Where loading/unloading area drainage does not flow into a catchment basin or treatment facility designed to handle discharges, use a quick drainage system for tank car or tank truck loading and unloading areas. You must design any containment system to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility.

(2) Provide an interlocked warning light or physical barrier system, warning signs, wheel chocks, or vehicle break interlock system in loading/unloading areas to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines.

(3) Prior to filling and departure of any tank car or tank truck, closely inspect for discharges the lowermost drain and all outlets of such vehicles, and if necessary, ensure that they are tightened, adjusted, or replaced to prevent liquid discharge while in transit.

(i) If a field-constructed aboveground container undergoes a repair, alteration, reconstruction, or a change in service that might affect the risk of a discharge or failure due to brittle fracture or other catastrophe, or has discharged oil or failed due to brittle fracture failure or other catastrophe, evaluate the container for risk of discharge or failure due to brittle fracture or other catastrophe, and as necessary, take appropriate action.

(j) In addition to the minimal prevention standards listed under this section, include in your Plan a complete discussion of conformance with the applicable requirements and other effective discharge prevention and containment procedures listed in this part or any applicable more stringent State rules, regulations, and guidelines.

(k) *Qualified Oil-filled Operational Equipment.* The owner or operator of a facility with oil-filled operational equipment that meets the qualification criteria in paragraph (k)(1) of this subsection may choose to implement for this qualified oil-filled operational equipment the alternate requirements as described in paragraph (k)(2) of this sub-section in lieu of general secondary containment required in paragraph (c) of this section.

(1) *Qualification Criteria—Reportable Discharge History:* The owner or operator of a facility that has had no single discharge as described in §112.1(b) from any oil-filled operational equipment exceeding 1,000 U.S. gallons or no two discharges as described in §112.1(b) from any oil-filled operational equipment each exceeding 42 U.S. gallons within any twelve month period in the three years prior to the SPCC Plan certification date, or since becoming subject to this part if the facility has been in operation for less than three years (other than oil discharges as described in §112.1(b) that are the result of natural disasters, acts of war or terrorism); and

(2) *Alternative Requirements to General Secondary Containment.* If secondary containment is not provided for qualified oil-filled operational equipment pursuant to paragraph (c) of this section, the owner or operator of a facility with qualified oil-filled operational equipment must:

(i) Establish and document the facility procedures for inspections or a monitoring program to detect equipment failure and/or a discharge; and

(ii) Unless you have submitted a response plan under §112.20, provide in your Plan the following:

(A) An oil spill contingency plan following the provisions of part 109 of this chapter.

(B) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

[67 FR 47140, July 17, 2002, as amended at 71 FR 77292, Dec. 26, 2006]

HEARING EXHIBIT - 00000849

Subpart B—Requirements for Petroleum Oils and Non-Petroleum Oils, Except Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and Vegetable Oils (Including Oils from Seeds, Nuts, Fruits, and Kernels)

SOURCE: 67 FR 47146, July 17, 2002, unless otherwise noted.

§ 112.8 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).

If you are the owner or operator of an onshore facility (excluding a production facility), you must:

(a) Meet the general requirements for the Plan listed under §112.7, and the specific discharge prevention and containment procedures listed in this section.

(b) *Facility drainage.* (1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, as provided in paragraphs (c)(3)(ii), (iii), and (iv) of this section.

(3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.

(4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.

(5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two "lift" pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in §112.1(b) in case there is an equipment failure or human error at the facility.

(c) *Bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.

(2) Construct all bulk storage tank installations (except mobile refuelers) so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

(3) Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in §112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

HEARING EXHIBIT - 00000850

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§ 122.41(j)(2) and 122.41(m)(3) of this chapter.

(4) Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

(5) Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.

(6) Test each aboveground container for integrity on a regular schedule, and whenever you make material repairs. The frequency of and type of testing must take into account container size and design (such as floating roof, skid-mounted, elevated, or partially buried). You must combine visual inspection with another testing technique such as hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or another system of non-destructive shell testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

(7) Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.

(8) Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

(9) Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in § 112.1(b).

(10) Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

(11) Position or locate mobile or portable oil storage containers to prevent a discharge as described in § 112.1(b). Except for mobile refuelers, you must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

(d) *Facility transfer operations, pumping, and facility process.* (1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage,

HEARING EXHIBIT - 00000851

you must undertake additional examination and corrective action as indicated by the magnitude of the damage.

(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.

(3) Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

[67 FR 47146, July 17, 2002, as amended at 71 FR 77293, Dec. 26, 2006]

§ 112.9 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil production facilities.

If you are the owner or operator of an onshore production facility, you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed under this section.

(b) *Oil production facility drainage.* (1) At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in § 112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under § 112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in § 112.8(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

(c) *Oil production facility bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage.

(2) Provide all tank battery, separation, and treating facility installations with a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely confine drainage from undiked areas in a catchment basin or holding pond.

(3) Periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground.

(4) Engineer or update new and old tank battery installations in accordance with good engineering practice to prevent discharges. You must provide at least one of the following:

(i) Container capacity adequate to assure that a container will not overfill if a pumper/gauger is delayed in making regularly scheduled rounds.

(ii) Overflow equalizing lines between containers so that a full container can overflow to an adjacent container.

(iii) Vacuum protection adequate to prevent container collapse during a pipeline run or other transfer of oil from the container.

(iv) High level sensors to generate and transmit an alarm signal to the computer where the facility is subject to a computer production control system.

(d) *Facility transfer operations, oil production facility.* (1) Periodically and upon a regular schedule inspect all aboveground valves and piping associated with transfer operations for the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items.

HEARING EXHIBIT - 00000852

(2) Inspect saltwater (oil field brine) disposal facilities often, particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge.

(3) Have a program of flowline maintenance to prevent discharges from each flowline.

§ 112.10 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.

If you are the owner or operator of an onshore oil drilling and workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Position or locate mobile drilling or workover equipment so as to prevent a discharge as described in § 112.1(b).

(c) Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.

(d) Install a blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

§ 112.11 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

If you are the owner or operator of an offshore oil drilling, production, or workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Use oil drainage collection equipment to prevent and control small oil discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment. You must control and direct facility drains toward a central collection sump to prevent the facility from having a discharge as described in § 112.1(b). Where drains and sumps are not practicable, you must remove oil contained in collection equipment as often as necessary to prevent overflow.

(c) For facilities employing a sump system, provide adequately sized sump and drains and make available a spare pump to remove liquid from the sump and assure that oil does not escape. You must employ a regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(d) At facilities with areas where separators and treaters are equipped with dump valves which predominantly fail in the closed position and where pollution risk is high, specially equip the facility to prevent the discharge of oil. You must prevent the discharge of oil by:

(1) Extending the flare line to a diked area if the separator is near shore;

(2) Equipping the separator with a high liquid level sensor that will automatically shut in wells producing to the separator; or

(3) Installing parallel redundant dump valves.

(e) Equip atmospheric storage or surge containers with high liquid level sensing devices that activate an alarm or control the flow, or otherwise prevent discharges.

(f) Equip pressure containers with high and low pressure sensing devices that activate an alarm or control the flow.

(g) Equip containers with suitable corrosion protection.

(h) Prepare and maintain at the facility a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems.

(i) Conduct testing and inspection of the pollution prevention equipment and systems at the facility on a scheduled periodic basis, commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations. You

HEARING EXHIBIT - 00000853

must use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems.

(j) Describe in detailed records surface and subsurface well shut-in valves and devices in use at the facility for each well sufficiently to determine their method of activation or control, such as pressure differential, change in fluid or flow conditions, combination of pressure and flow, manual or remote control mechanisms.

(k) Install a BOP assembly and well control system during workover operations and before drilling below any casing string. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while the BOP assembly and well control system are on the well.

(l) Equip all manifolds (headers) with check valves on individual flowlines.

(m) Equip the flowline with a high pressure sensing device and shut-in valve at the wellhead if the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to and including the header valves. Alternatively you may provide a pressure relief system for flowlines.

(n) Protect all piping appurtenant to the facility from corrosion, such as with protective coatings or cathodic protection.

(o) Adequately protect sub-marine piping appurtenant to the facility against environmental stresses and other activities such as fishing operations.

(p) Maintain sub-marine piping appurtenant to the facility in good operating condition at all times. You must periodically and according to a schedule inspect or test such piping for failures. You must document and keep a record of such inspections or tests at the facility.

Subpart C—Requirements for Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and for Vegetable Oils, including Oils from Seeds, Nuts, Fruits, and Kernels.

SOURCE: 67 FR 57149, July 17, 2002, unless otherwise noted.

§ 112.12 Spill Prevention, Control, and Countermeasure Plan requirements.

If you are the owner or operator of an onshore facility (excluding a production facility), you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed in this section.

(b) *Facility drainage.* (1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, subject to the requirements of paragraphs (c)(3)(ii), (iii), and (iv) of this section.

(3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.

HEARING EXHIBIT - 00000854

(4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.

(5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two "lift" pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in §112.1(b) in case there is an equipment failure or human error at the facility.

(c) *Bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.

(2) Construct all bulk storage tank installations (except mobile refuelers) so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

(3) Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in §112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§122.41(j)(2) and 122.41(m)(3) of this chapter.

(4) Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

(5) Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.

(6) Test each aboveground container for integrity on a regular schedule, and whenever you make material repairs. The frequency of and type of testing must take into account container size and design (such as floating roof, skid-mounted, elevated, or partially buried). You must combine visual inspection with another testing technique such as hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or another system of non-destructive shell testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

(7) Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.

(8) Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly

HEARING EXHIBIT - 00000855

attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

(9) Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in §112.1(b).

(10) Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

(11) Position or locate mobile or portable oil storage containers to prevent a discharge as described in §112.1(b). Except for mobile refuelers, you must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

(d) *Facility transfer operations, pumping, and facility process.* (1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.

(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.

(3) Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

[67 FR 57149, July 17, 2002, as amended at 71 FR 77293, Dec. 26, 2006]

§§ 112.13–112.15 [Reserved]

Subpart D—Response Requirements

§ 112.20 Facility response plans.

(a) The owner or operator of any non-transportation-related onshore facility that, because of its location, could reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines shall prepare and submit a facility response plan to the Regional Administrator, according to the following provisions:

(1) For the owner or operator of a facility in operation on or before February 18, 1993 who is required to prepare and submit a response plan under 33 U.S.C. 1321(j)(5), the Oil Pollution Act of 1990 (Pub. L. 101-380, 33 U.S.C. 2701 *et seq.*) requires the submission of a response plan that satisfies the requirements of 33 U.S.C. 1321(j)(5) no later than February 18, 1993.

(i) The owner or operator of an existing facility that was in operation on or before February 18, 1993 who submitted a response plan by February 18, 1993 shall revise the response plan to satisfy

HEARING EXHIBIT - 00000856

Attachment C

HEARING EXHIBIT - 00000857

Alabama Metal Fabricators, Inc.

June 19, 2008

Marie Largilliere
Gulf Power Lansing Smith
P.O. Box 1210
Lynn Haven, FL 32444-1210

RE: Concrete Containment Wall

Dear Ms. Largilliere,

Alabama Metal Fabricators, Inc. appreciates the opportunity to quote the above referenced project. We will supply the material and labor to form and pour the slab and containment wall. The slab will be 5" thick x 9'-6" x 13'-6", with the wall being 6" wide x 14" tall. Both will have #4 rebar for internal strength and will be poured with 4000 pounds of concrete.

The cost for this project will be $9,282.00 (Nine thousand two hundred eighty-two dollars). Please allow 2 to 3 weeks after receipt of order to complete. If you have any questions, please do not hesitate to contact me at 251-986-6257.

Sincerely,

David Weaver
Estimator

DW/tms

27094 HIGHWAY U.S. 98 • ELBERTA, ALABAMA 36530 • PHONE (251) 986-6257 • FAX (251) 986-6258
Website: www.almetalfab.com • E-mail: amf@almetalfab.com

HEARING EXHIBIT - 00000858

Attachment D

HEARING EXHIBIT - 00000859

Northwest Florida Water Management District

Division of Resource Regulation
152 Water Management Drive, Havana, Florida 32333-4711
(U.S. Highway 90, 10 miles west of Tallahassee)
(850) 539-5999 • (Suncom) 793-5999 • (Fax) 539-2777

Douglas E. Barr
Executive Director

January 28, 2005

Gulf Power, Inc.
Crist Electric Generating Plant
One Energy Place
Pensacola, FL 32520-0328

NOTICE OF AGENCY ACTION
Individual Water Use Permit No. 19850074
Consumptive Use Permit Application No. I06475

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 January 27, 2005. 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.

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 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
Division of Resource Regulation

Enclosure
cc: Richard M. Markey

JOYCE ESTES, Chair, Eastpoint
L. E. MCMULLIAN, Vice Chair, Sneads
STEPHANIE H. BLOYD, Secretary/Treasurer, Panama City Beach
LOIS BENSON, Pensacola
WAYNE BODIE, DeFuniak Springs
PAUL BRADSHAW, Havana
HULAN CARTER, Chipley
SHARON T. GASKIN, Wewahitchka
RICHARD PETERMANN, Fort Walton Beach

HEARING EXHIBIT - 00000860

NORTHWEST FLORIDA WATER MANAGEMENT DISTRICT
INDIVIDUAL WATER USE PERMIT
(NWFWMD Form No. A2-E)

Permit granted to:

Gulf Power Company
Crist Electrical Generating Plant
One Energy Place

Pensacola, Florida 32520-0328
(Legal Name and Address)

Permit No.: 19850074 Modification/Renewal

Date Permit Granted: January 27, 2005

Permit Expires On: February 1, 2010

Source Classification: Sand-and-Gravel Aquifer
Governor's Bayou/
Escambia River

Use Classification: Public Supply
Power Generation

County: Escambia Area: C

Location: Section 25 1/4 Section

Application No.: 106475

Township 1 North Range 30 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.

HEARING EXHIBIT - 00000861

5. This Permit authorizes the Permittee to make a combined average annual withdrawal of **257,500,000*** gallons of water per day, a maximum combined withdrawal of **305,400,000**** gallons during a single day, and a combined monthly withdrawal of **9,366,700,000***** 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
CEGP #2 (AAA6423)	Sec. 25, TIN, R30W		720,000 Abandoned
CEGP #3 (AAA6421)	Sec. 25, TIN, R30W		1,080,000
CEGP #4 (AAA6418)	Sec. 25, TIN, R30W		1,080,000
CEGP #5 (AAA6420)	Sec. 25, TIN, R30W		1,080,000
CEGP #6 (AAA6419)	Sec. 25, TIN, R30W		1,080,000
CEGP #7	Sec. 25, TIN, R30W		1,080,000
CEGP 1A	Sec. 25, TIN, R30W		24,480,000
CEGP 1B	Sec. 25, TIN, R30W		24,480,000
CEGP 2A	Sec. 25, TIN, R30W		24,480,000
CEGP 2B	Sec. 25, TIN, R30W		24,480,000
CEGP 3A	Sec. 25, TIN, R30W		28,800,000
CEGP 3B	Sec. 25, TIN, R30W		28,800,000
CEGP 4A	Sec. 25, TIN, R30W		56,160,000
CEGP 4B	Sec. 25, TIN, R30W		56,160,000
CEGP 5A	Sec. 25, TIN, R30W		56,160,000
CEGP 5B	Sec. 25, TIN, R30W		56,160,000
CEGP 6A/7A	Sec. 25, TIN, R30W		17,568,000
CEGP 6B/7B	Sec. 25, TIN, R30W		17,568,000
CEGP 7C/7C	Sec. 25, TIN, R30W		17,568,000

* 2,500,000 Ground Water – 255,000,000 Surface Water
** 5,400,000 Ground Water – 300,000,000 Surface Water
*** 88,360,000 Ground Water – 9,278,300,000 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.

HEARING EXHIBIT - 00000862

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

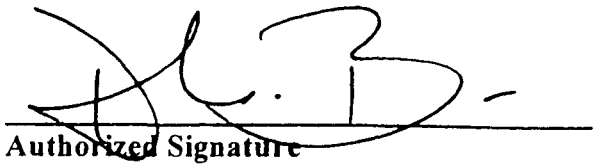
(a) In the event of a declared water shortage, water withdrawal reductions shall be made as ordered by the District.

(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.

HEARING EXHIBIT - 00000863

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

HEARING EXHIBIT - 00000864

ATTACHMENT
Gulf Power Company
Crist Electrical Generating Plant

Individual Water Use Permit No. 19850074
Individual Water Use Application No. I06475

1. The Permittee shall include the Individual Water Use Permit number and each well's Florida Unique Identification Number (e.g., AAA###) when submitting reports or otherwise corresponding with the District.

2. The Permittee shall maintain, in working order, in-line totaling flow meters on the well head of each production well.

3. The Permittee shall record the data required on 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 and surface water). The ground and surface water withdrawals shall also be provided as a combined total. 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 report for the year 2005 is due by January 31, 2006.

4. The Permittee, by January 31 of each year, shall report the following information:

   a. Water quality sample results from withdrawal well AAA6421 (CEPG #3) collected during the first two weeks of each month and analyzed for sodium, chloride, sulfate, bicarbonate, carbonate, calcium, magnesium, potassium, specific conductance, total dissolved solids and pH. Prior to sampling, the Permittee shall purge three to five well volumes from the well, and shall report with the test results, the purging duration, volume and rate used.

   b. Static water level data for each production well during the first two weeks of January, April, July, and October. The water level data shall be referenced to mean sea level.

   The Permittee, if preferred, may submit the reports electronically by e-mailing the data to compliance@nwfwmd.state.fl.us.

   The Permittee shall immediately initiate monthly collection, analysis, and reporting of ground-water quality samples and ground-water levels from all withdrawal wells identified in this permit, should drawdowns or water quality exceed a level of concern, as determined by the District. In this event, the Permittee shall, within 30 days, submit a written plan to the District identifying the specific actions it will implement to address the issue(s) of concern including monthly recording of the required data.

HEARING EXHIBIT - 00000865

5. The Permittee shall continue to return at least 95% of the surface water withdrawn from Governor's Bayou/Escambia River. The Permittee shall submit a statement to this effect by January 31 of each year. The first statement is due by January 31, 2006.

6. The Permittee shall implement measures to increase water conservation and efficiency at the facility. The Permittee, by January 31 of each year, shall submit to the District a report detailing the actions taken, and the progress during the previous year, in achieving the stated goal. The first submittal is due by January 31, 2006.

7. The Permittee shall mitigate interference to existing users that is attributable to the withdrawal amounts authorized herein, should it occur. The Permittee shall report the occurrence of any such interference to the District and shall identify the mitigation action undertaken to address the interference.

HEARING EXHIBIT - 00000866

2.9.51

GULF POWER
A SOUTHERN COMPANY

January 28, 2008

Northwest Florida Water Management District
Division of Resource of Regulation
152 Water Management Drive
Havana, Florida 32333-9700

Dear Mr. Sir/Madam:
Individual Water Use Permit No. 19850074 Gulf Power Company Crist Electric Generating Plant

This letter is intended to present the District with the permit-required information. Attached are the copies of the quarterly static level readings from the wells, and the required analytical results for Well No. 3 and for Well No.5 that were sampled as part of our Groundwater Monitoring Plan. In addition the Water Use Summary Sheets are included.

Permit condition 5 indicates that the permittee shall implement measures to conserve water. The plant has installed level controllers and valves to keep the fire tanks full without overflowing. In 2004 the plant abandoned the CEGP # 2 that was previously used to wash the intake screens.

Permit condition 5 requires the plant to return at least 95% of the surface water withdrawn. The plant continues to operate in accordance with this requirement.

In addition to the description above, reductions in the groundwater withdrawals have been accomplished by the following:

1) Clear water reductions of an estimated 15,768,000 gal/yr by eliminating the cooling water to the no. 2 demineralizer booster pumps.
2) Clear water reduction of an estimated 175,200 gal/yr. by recycling pH sample lines from Units 6 & 7 back into the service water tanks.

Rainfall is collected from a stormwater pond at the landfill and a portion is transferred to the Cooing water basin for unit 6. The new cooling tower has improved drift eliminators that reduce the fog produced which equates to water losses.

If any questions arise concerning the information in these reports, please call me at (850) 444-6429.

Sincerely,

Joe Neese
Environmental Specialist

Attachments

cc: John Dominey
Mike Markey

HEARING EXHIBIT - 00000867

Attachment E

HEARING EXHIBIT - 00000868

Gulf Power Company
Plant Crist Unit 6 & 7
ECUA Reclaimed Water Project

INTRODUCTION

Gulf Power Company's Plant Crist is a coal-fired generating facility located in Pensacola, Florida. To reduce the amount of water drawn from the Governor's Bayou of the Escambia River, Gulf Power Company has partnered with Emerald Coast Utilities Authority (ECUA) to reuse reclaimed water. The reclaimed water will be used as makeup water for the scrubber system and for unit 6 and 7 cooling towers. To satisfy regulatory requirements, the reclaimed water has to be used in unit 7 circulating water system before it can be supplied to the scrubber system. When unit 7 circulating water is out of service the reclaimed water will be supplied directly to the scrubber system. Plant Crist will also return the used and un-used reclaimed water, up to a maximum of 6 million gallons per day (MGD), to ECUA as industrial wastewater for land application. As a result of the ECUA regulatory requirements, river water must be use to supply units 4, 5, 6, and 7 ash sluice systems. The river water will be pumped from the 4/5 intake structure to the existing ash sluice systems. In case of a 100 year flood a Canal drawn down system will be designed to pump water out of unit 6 intake canal to unit 4/5 discharge tunnel.

SCOPE DEFINITION

ECUA Return and Supply

The reclaimed water will be sent to two new pipelines that shall be installed at the property boundary of Plant Crist near Clear Creek. ECUA will design a 30" and 20" pipelines from their water facility to Plant Crist property boundary. Southern Company Mechanical group will design and route a 30" and 16" pipeline from the boundary to a new enclosed pit – which will be the final designation for the pipes – located near the 4/5 intake structure. The 30" pipeline will be the "Service Pipe" from ECUA to Plant Crist and the 16" pipeline will be the "Return Pipe" from Plant Crist to ECUA. The Service Pipe will be designed to supply water to the following systems or locations: unit 6 and 7 cooling tower, scrubber makeup water tank, and the 4/5 intake tunnel. The 16" return line will tie into a vertical pump discharge header. Two (2) 4200 gallon per minute (GPM) vertical pumps will be installed. These vertical pumps will be placed over a new enclosed pit to pump the blowdown water from unit 6 and 7 cooling tower back to ECUA. The 30" supply line will be reduced to two (2) 16" pipes near the 4/5 stack. The first 16" supply line will be routed to the 4/5 intake tunnel at coordinate N: 579523.6 E: 1111300.41 Z: 73.00 The second 16" supply line will be routed to the enclosed pit. Also, the existing 30" blowdown pipe will be modified to send the blowdown water to the enclosed pit. The water in the new closed pit will be pumped back to ECUA through the 16" return line and tie into the 20"return pipeline at the property boundary. In order not to exceed the maximum 6 MGD return water to ECUA, two (2) additional 4000 GPM pumps will be installed at the enclosed pit to pump water to the 4/5 intake tunnel.

HEARING EXHIBIT - 00000869

Ash Sluice System

The existing units 4, 5, 6 and 7 ash sluice systems shall be modified to take water from Escambia River. Three (3) new 4800 GPM vertical pumps will be installed between the 4/5 intake structure screens and the new ECUA 4/5 intake tunnel feed to delivery water to the existing ash sluice systems. Two (2) pumps shall be sized to supply the maximum required flow to the ash sluice systems, with one (1) pump being an available back-up. A new pipeline will be routed from the new ash sluice header supply pumps to the existing units 4, 5, 6 and 7 existing ash sluice pumps located in various locations of the plant. This pipeline shall be composed of both carbon steel and HDPE piping. The existing units 4, 5, 6 and 7 ash sluice feed systems shall be isolated from the new supply system.

There shall also be two (2) new refractory cooling jockey pumps installed at the 4/5 intake structure. These pumps shall be used to supply river water to Refractory Cooling in the event none of the Ash Sluice Header Supply Pumps are not in service. One pump shall serve as a back-up. When one of the Ash Sluice Header Supply Pumps are in service, the Refractory Cooling Jockey Pumps shall be out of service. These pumps shall be tied into the same piping system used for the new ash sluice system.

As a result of the new Refractory Cooling Jockey Pumps, the existing Refractory Cooling Pumps PPCH 610A and B located in the vicinity of the Unit 6 Ash Sluice Pumps shall be removed from service. The new pumps shall supply sufficient flow and pressure to supply to Refractory Cooling.

Canal Drawdown System

In the event of a 100 year flood, a Canal drawdown system will be designed to pump water from the unit 6 intake canal to unit 4/5 discharge tunnel. Three pumps (3) will be installed in the sub-basement of unit 6, between columns HX 25-1/3 and I 24-1/3. When intake canal 6 water level exceeds sea level elevation of 97', two of the Canal Drawdown pumps will be used for operation. The third pump is used as a spare.

The 20" suction pipe for the new Canal Drawdown Pumps will tie into unit 6 condenser inlet pipe, which is located east of the pumps. There will be a manual valve on the suction pipe that will be opened in the event of a flood. This will allow water from the condenser inlet to flow into the suction pipe of the Canal Drawdown Pumps. It is important to note, the valve for the unit 6 circulating pumps, must be in the open position to allow water from the canal to flow into the condenser inlet pipe.

The discharge pipes of the Canal Drawdown Pumps will tie into a common header above the pumps. This 20" discharge pipe will then be routed from the sub-basement of unit 6 to the basement floor of unit 5 near Column 17-I. The Canal Drawdown Pumps discharge pipe will then tie into unit 4/5 cooling water pipe, near column Fc18, which discharges water into unit 4/5 discharge tunnel.

HEARING EXHIBIT - 00000870

MECHANICAL

Mechanical Project Scope of Work:

1. Provide field constructability walk down to determine existing space available for equipment layout, pipe routing and supports.
2. Prepare equipment specification and piping bill of materials for purchase.
3. Prepare equipment layout and pipe routing drawings (Isometrics, pipe support plans, plans and details).
4. Review and approve vendor drawings.
5. Provide construction support during installation.

Mechanical Work Included:

Provide for the following:

1. Prepare the specification, bid evaluation and recommendation, as well as, the requisition necessary to purchase all valves, piping, and pumps.
2. Review and approve vendor drawings.
3. Prepare all necessary design drawings including equipment layout and pipe routing for bid packages.
4. Provide piping layout locations and loads to Civil Discipline for use in designing the pumping pit foundation and piping supports.
5. Transmit to Document Control all final drawings including field changes for:
   - Routing of pipes from Plant Crist property boundary line to the new pumping pit with new control valve, isolation valve, and flow meter.
   - Routing of piping from 4/5 intake structure ash sluice pumps make up pump to the units 4, 5, 6 and 7 existing ash sluice pumps with new control valves and isolation valves.
   - Routing of piping from Refractory Cooling Jockey Pumps to the new ash sluice supply piping.
   - Routing of pipes from canal draw down pumps near unit 6 condenser inlets to 4 & 5 intake tunnel with manual valve, isolation valve and flow meter.

Mechanical Assumptions:

1. The Plant shall approve the proposed equipment location and pipe routing prior to start the design.
2. Design and procure the diversion tees and valves for all designed locations on the flow diagram.

HEARING EXHIBIT - 00000871

ELECTRICAL

Electrical Project Scope of Work:

1. Provide field constructability walk down to determine existing available space for electrical equipment building, any demolition requirements and raceway routing feasibility.
2. Provide field constructability walk down to determine power source availability.
3. Prepare single line diagrams and conceptual estimate.
4. Prepare cable sizing calculation for all electrical loads.
5. Prepare cable pulling calculations for worst case pulling conditions.
6. Design and layout PEEC equipment for new electrical building and surrounding area.
7. Design and layout equipment, raceway and grounding in the ECUA pump area, the Ash Sluice pump area and the Canal Drawdown pump area in the sub-basement of Unit 6 Turbine Building for motors, valves and instrumentation.
8. Provide grounding, lightning protection, lighting, heat tracing and fiber optic design as required.
9. Prepare design drawings including elementary and wiring diagrams.
10. Input data into the (PDMS) to develop cable pull & termination cards, bill of material, raceway and cable schedules.
11. Prepare & issue equipment specifications and bid evaluations.
12. Prepare and issue requisitions.
13. Review and approve other discipline's drawings.
14. Review and approve vendor drawings.
15. Provide field support during Construction.
16. As-built & Red-line Drawings
17. Transmit to Document Control final electrical drawings including field changes.

Power Supply Design Philosophy

- Power for the new ECUA Electrical building will be derived from the Scrubber new 4.16kV switchgears located in the JBR building.

- Two new 4.16kV motor control centers will be located in the ECUA Electrical building to power the (2) ECUA Return pump-motors, (3) Ash Sluice pump-motors and (2) 4160-480V power transformers.

- The transformers will power two new 480V motor control centers located in the ECUA Electrical building. The 480V MCC's will power the (2) ECUA Surplus & the (2) Refractory Cooling jockey pump-motors, distribution systems for motor operated valves and misc loads associated with the new ECUA electrical building.

Refer to drawing **D39070** for Master Single line Diagram.

- The (3) Canal Drawdown pump-motors will be fed from existing 600V motor control center 6F located in the Unit 6, elevation 132'.

Electrical Work Included:

ECUA Electrical Building

1. Existing Demineralizer building superstructure will be demolished, and a new electrical equipment building will be placed, with care taken not to damage any grounding or piping which is to remain for later connections. Civil discipline will address any action to be taken to modify the foundation for the new PEEC building.

2. A 16 ft x 50 ft pre-fabricated building will be procured with all electrical equipment such as the 4160V & the 480V MCC's, distribution panel boards and dry-type transformers, etc. and all cable tray, all indoor & outdoor lighting fixtures, receptacles, HVAC and equipment already installed and set in place before shipment. Equipment shall be installed, if practical, and shop tested prior to shipping. The building finished floor EL. will be 97'+/-. Refer to drawings **D39170** & **D39173** for building equipment contents and physical arrangement.

3. Define (for Civil) any stairs, platforms, oil containment, and Tee poles around electrical building needed for access and maintenance of HVAC equipment and power transformers. The base EL. of the transformers will be 97' +/-.

4. The existing ground cables stubbed out of the existing foundation corners are to be tested for continuity and readings prior to use with the new system. A ground loop shall be designed around the power transformers with ground rods driven to an 80' depth or refusal.

5. The building will be protected by addition of 8 – 18" air terminals along the ridge of the building roof. The air terminals will be connected to a 4/0 down-lead which will be carried to the existing ground cables at the four corners of the building support. The down-lead will also be connected to the support column (if present) with a Cadweld connection.

6. The (2) 4.16kV circuits providing power to the ECUA bldg from the JBR bldg will be routed in cable 2-12" tray runs approximately 1,100'. Fiber optic cables for control, security & LAN will be routed in the same redundant trays. These trays will be field-routed and supported.

Demineralizer Bldg and Chemical & Results Distribution

The Demineralizer bldg is currently fed from a 70A breaker of the existing 600V motor control center located in the Coal Handling house. Chemical & Results 120/208V distribution and outdoor lighting for the oil storage area are currently fed from a 120/208V distribution panel which is fed from the 600V motor control center via a 600-208/120V step-down transformer located in the Demineralizer Bldg.

It was decided that after demolition of the Demineralizer bldg:

1. The 70A breaker of the existing 600V motor control center located in the Coal Handling house will be utilized to feed the Chemical & Results 120/208V distribution via a new 45kVA transformer to be located @ the C&R pit area. Additional equipment, raceway and grounding design is required at this area. This work will be completed prior to demolition effort.

2. The outdoor lighting for the oil storage area will be fed from the new ECUA electrical building. Prior to completion of the ECUA electrical bldg, lighting will be fed temporary from the construction power.

ECUA Supply and Return

1. Design a raceway system and power, control & low level signal cabling from the ECUA electrical building to the ECUA pumps pit and within the pit area, including equipment, grounding, lighting and supports. Tee pole supports are required by Civil for overhead raceway.

2. The ECUA Return & Surplus pumps will be controlled via a HOA control station and the DCS located in the ECUA electrical bldg.

3. The motor operated valves within the pumps pit area will be powered from a new local 120/208V distribution system. The MOVs will be controlled from the DCS in the ECUA electrical bldg.

4. MOVs at the 6&7 Cooling Tower Makeup will be powered & controlled from the new Gypsum electrical building.

5. MOV at ECUA Scrubber line will be powered & controlled from the new JBR electrical building.

Ash Sluice System

1. Design a raceway system and power, control & low level signal cabling from the ECUA electrical building to the Ash Sluice pumps pit and the surrounding 4/5 intake canal area, including equipment, grounding and supports. Tee pole supports are required by Civil for overhead raceway.

2. Design an underground raceway system under the roadway access to the screen area and direct buried conduit as required.

3. The Ash Sluice HDR Supply & Refractory Cooling pumps will be controlled via a HOA control station and the DCS located in the ECUA electrical bldg.

4. The motor operated valves within the pumps pit area will be powered from a new local 120/208V distribution system. The MOVs will be controlled from the DCS in the ECUA electrical bldg.

HEARING EXHIBIT - 00000874

5. The air operated valves at Units 4/5, 6 & 7 Ash Sluice Pumps in the sub-basement controlled from the DCS in the ECUA electrical bldg.

Canal Drawdown

1. Design a raceway system and power & low level signal cabling from the Canal Drawdown pump location in Unit 6 sub-basement to the Unit 6 relay room and MCC 6F location on EL.132 platform and within the pump area, including equipment, grounding and supports.

2. The Canal Drawdown pumps will be controlled automatically via the DCS in the Unit 6 relay room.

3. The canal level transmitter will be wired to the DCS in the Unit 6 relay room.

Miscellaneous

1. There are valves, flow devices and various instruments and heat tracing which are located in remote areas, requiring power, control and low level signal cables to be routed from plant sources/destinations agreed upon with plant representatives.

Electrical Assumptions:

1. Plant approves the demolition of the existing Demineralizer building and the erection of the proposed ECUA Electrical building.
2. Plant approves the use of spare buckets/breakers of the 600V motor control center 6F to power the (3) Canal Drawdown pump motors.
3. B&V approves the 4.16kV feeds to the ECUA electrical bldg from the new 4.16kV Scrubber switchgears in the JBR bldg.
4. B&V approves the feeds to new MOVs from the JBR and Gypsum buildings and utilization of raceways in the duct bank running to the Gypsum building.
5. Sole source for the ECUA (PEEC) Electrical Building.
6. Accuracy of Motor HP ratings from Mechanical discipline.
7. Accuracy of PI&D & piping drawings from Mechanical discipline.
8. One out of two ECUA Return Pump will be running
9. All two (2) ECUA Surplus Pumps will be running
10. One out of two Refractory Cooling Pump will be running
11. All three (3) Ash Sluice Header Supply Pumps will be running
12. Two out of three Canal Drawdown Pumps will be running

HEARING EXHIBIT - 00000875

CIVIL

Civil Project Scope of Work:

Scope includes the following items.

1. Provide field constructability walk down to determine existing space available for equipment layout, pipe routing and supports.
2. Provide design for the ECUA Supply and Return pumping pit.
3. Provide design for Ash Sluice Pumping structure
4. Provide design for pipe supports.
5. Provide design for a manhole near cooling tower # 6.
6. Provide foundation design for the new Electrical switchgear building.
7. Provide all necessary design drawings.

Civil Work Included:

ECUA Supply and Return

1. Design pipe support bridge spanning canal and roads north of cooling tower #6
2. Design valve pit on north east side of cooling tower #6.
3. Verify and modify existing precipitator #7 framing steel at top of steel el 116'-9" as required. Framing at north end for supporting 30" and 16" diameter pipes.
4. Design Pipe Bridge and set of t-poles north of precipitator #6 along existing coal wall for continuation of 30' and 16" diameter pipes.
5. Design cross over and t-poles from end of existing coal wall to edge of pipe trench going east towards existing duct support steel framing.
6. Verify and modify existing duct support steel for supporting continuation of pipe running south into existing unit #4 & #5 intake tunnel
7. Provide design and drawings for new ECUA pump pit west of fire water tank.

Ash Sluice System

1. Provide design & drawings for new Ash Sluice Pump structure pit.
2. Provide new concrete trench for routing of 20' diameter pipe under existing road south of new ash sluice pump pit.
3. Verify existing abandoned duct steel framing north of units #1 & #2 for routing of 20" diameter pipe.
4. Provide supports and verify existing structures from unit #3 thru unit #7 for routing of 12",14",18" and 20" diameter pipes
5. Provide structural drawings indicating new support and members that need to be reinforced.

Canal Drawdown

1. Provide supports for a 20" diameter pipe between unit # 5 & # 6 from top of concrete el. 60'-0" to top of concrete el. 75'-0"
2. Verify existing steel at support locations for new loads.
3. Provide structural steel drawings at reinforced locations.

HEARING EXHIBIT - 00000876

Electrical Building

1. Verify and modify existing demineralization building foundation for new electrical building
2. Provide design for stairs and platforms around electrical building for access and maintenance.
3. Provide design for platforms and containment around new transformers
4. Provide design for steel support of electrical building skid
5. Provide design for t-poles around and near electrical building
6. Provide t-poles around pump pits
7. Provide construction support during installation
8. Transmit final drawings to Document Control.

Civil Assumptions:

1. Lead discipline information will be available at time of design.
2. Certified vendor information will be available at time of design.
3. Foundations will use same piles as scrubber projects on site.
4. Design drawings will be based on latest grid coordinate system..

INSTRUMENTATION & CONTROL

Instrument & Control Project Scope of Work:

Provide control logic and control graphics for pump protection and system performance monitoring; control of the ECUA return, ash sluice and canal draw down pumps. Provide control logic to monitor flow for the canal draw down and ECUA return and supply system. Provide control logic to monitor all associated motor control operated valves.

1. Work with other discipline to review and revise P&ID.
2. Prepare all necessary control logic drawings.

Instrument & Control Work Included:

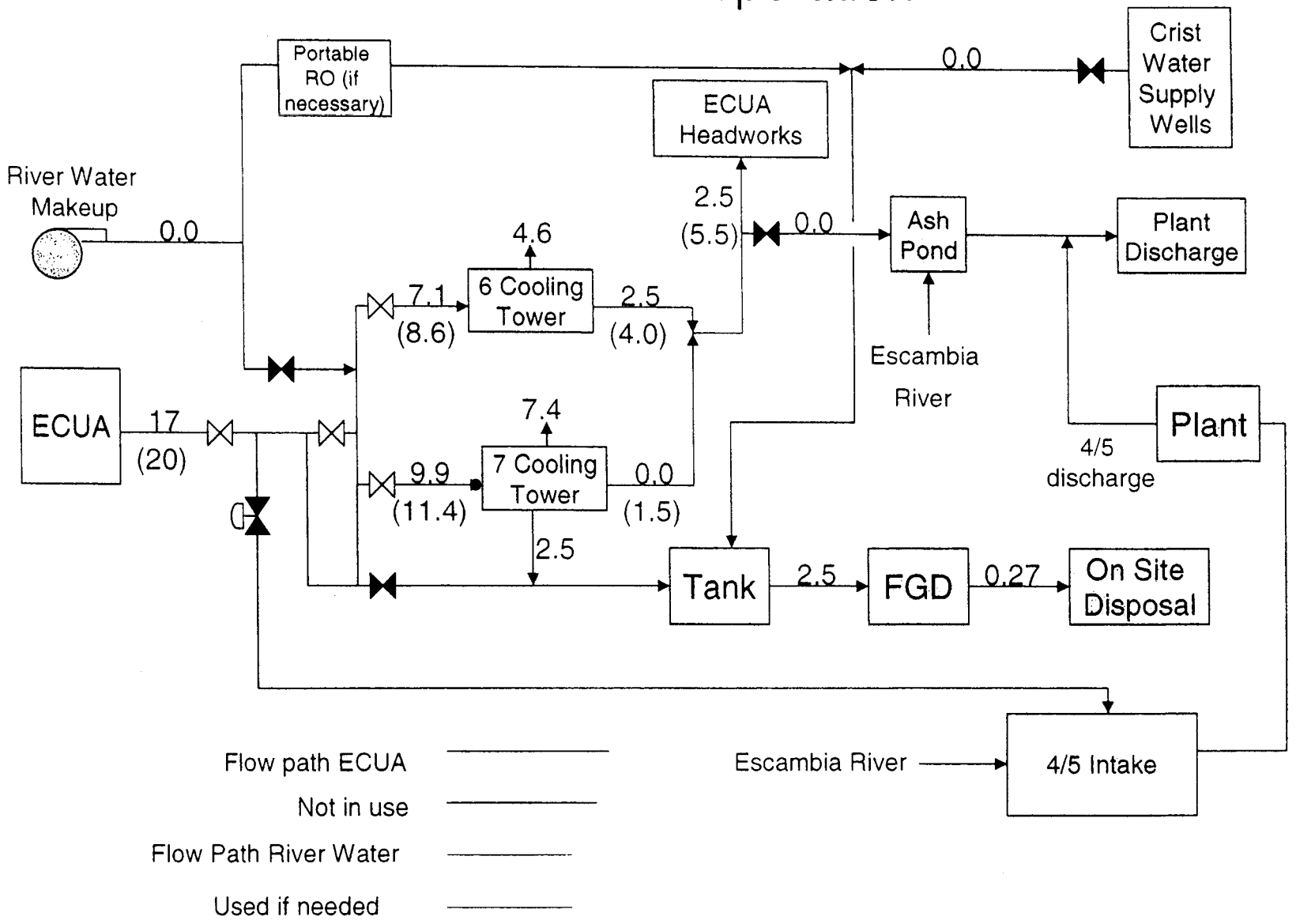
1. Prepare requisition and purchase all control equipment needed for all water systems.
2. Provide Ovation control sheets, instrument list, instrument location drawings, primary connection drawings and installation details. Updating of the FGD DCS point data base to include this new equipment.
3. Produce AS-Build drawings for these drawings.
4. Transmit to Document Control final design drawings including field changes.

Instrument & Control Assumptions:

1. ECG, project personnel and plant personnel will develop the operational requirements for each of the three subsystems for the FGD water systems.
2. The control of this equipment will be through the common FGD node of the Ovation distributed control system.
3. Remote DCS nodes will be located in electrical buildings. These nodes will be defined later.

Revised June 2008

ECUA normal operation



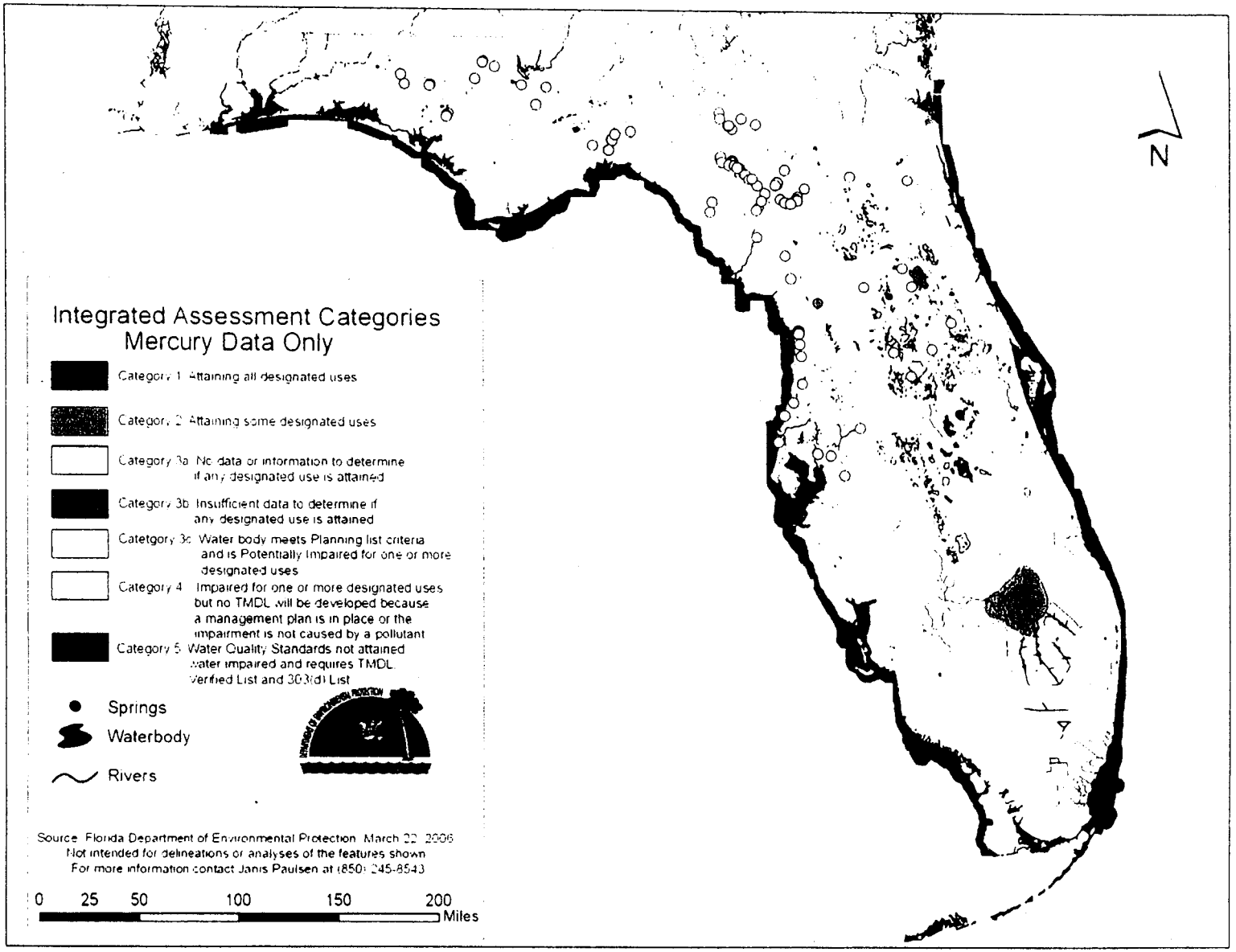
0548

HEARING EXHIBIT - 00000878

Attachment F

HEARING EXHIBIT - 00000879

Map of Hg Impaired Waterbodies



HEARING EXHIBIT - 00000880

Attachment G

HEARING EXHIBIT - 00000881

Apalachicola - Chipola Group 2 Basin - Northwest District - Verified List
Hydrologic Units - Apalachicola River, Chipola River

OCG Case Number	Basin Group Name	WBID	Water Segment Name	Waterbody Type	Waterbody Class	Parameters Assessed Using the IWR	Concentrations Causing Impairment	Priority for TMDL Development[1]	Projected Year for TMDL Development[1]	Comments[2] PP=Planning Period VP=Verified Period (#Exceedances/#Samples)
03 2374	Apalachicola Bay	1266	St George Sound	Estuary	2	Bacteria (in shellfish)	Exceeds SEAS thresholds	Medium	2008	Listed based on change in shelfish harvesting classification (downgraded from approved to conditionally restricted).
03 2375	Apalachicola Bay	1274	Apalachicola Bay	Estuary	2	Fecal Coliform	>400 colonies per 100 mL	High	2003	PP - 483/3256 Potentially Impaired VP - 215/1710 Verified Impaired
03 2376	Apalachicola Bay	1274	Apalachicola Bay	Estuary	2	Bacteria (in shellfish)	Exceeds SEAS thresholds	Medium	2008	Listed based on change in shelfish harvesting classification (downgraded from approved to conditionally restricted)
03 2377	Apalachicola Bay	1274A	East Bay	Estuary	2	Fecal Coliform	>400 colonies per 100 mL	Medium	2008	PP - 461/2047 Potentially Impaired VP - 150/900 Verified Impaired
03 2378	Apalachicola Bay	1274A	East Bay	Estuary	2	Bacteria (in shellfish)	Exceeds SEAS thresholds	Medium	2008	Listed based on change in shelfish harvesting classification (downgraded from conditionally approved to conditionally restricted)
03 2379	Apalachicola Bay	1274B	Apalachicola Bay	Estuary	2	Bacteria (in shellfish)	Exceeds SEAS thresholds	Medium	2008	Listed based on change in shelfish harvesting classification (downgraded from approved to conditionally approved).
03 2380	Apalachicola Bay	1288	Money Bayou	Estuary	3M	Bacteria (in shellfish)	Exceeds SEAS thresholds	Medium	2008	Listed based on change in shellfish harvesting classification (downgraded from unclassified to prohibited)
03 2381	Apalachicola River	1286	Huckleberry Creek	Stream	3F	Fecal Coliform	>400 colonies per 100 mL	High	2003	PP - No data VP - Verified impaired (11/23). Data from consultant for Apalachicola Wastewater Treatment Facility Monitoring.
03 2382	Apalachicola River	1286	Huckleberry Creek	Stream	3F	Dissolved Oxygen	BOD > 2.0 mg/L	Medium	2008	PP - No data VP - Verified impaired (19/22). Data from consultant for Apalachicola Wastewater Treatment Facility Monitoring. Causative pollutant is BOD (median value of approximately 3.0 mg/L).
03 2383	Apalachicola River	376	Mosquito Creek	Stream	1	Fecal Coliform	>400 colonies per 100 mL	Medium	2008	PP - 15/34 Potentially Impaired VP - 9/23 Verified Impaired
03 2384	Apalachicola River	376	Mosquito Creek	Stream	1	Total Coliform	>2400 per 100 mL	Medium	2008	PP - 14/30 Potentially Impaired VP - 10/23 Verified Impaired
03 2385	Apalachicola River	926A1	Lake Mystic	Stream	3F	Fish - Mercury	> 0.5 ug/L	Low	2011	PP - Not impaired VP - Listed based on fish tissue data. Eleven out of 20 fish sampled had mercury levels greater than 0.5 ppm, with a mean value of .554 ppm.
03 2386	Chipola River	51E	Chipola River	Stream	3F	Fecal Coliform	>400 colonies per 100 mL	Medium	2008	PP - 14/82 Not Impaired VP - 10/37 Verified Impaired
03 2387	Chipola River	52	Cowarts Creek	Stream	3F	Fecal Coliform	>400 colonies per 100 mL	Medium	2008	PP - 11/57 Not Impaired VP - 13/58 Verified Impaired
03 2388	Chipola River	52	Cowarts Creek	Stream	3F	Total Coliform	>2400 colonies per 100 mL	Medium	2008	PP - 18/52 Potentially Impaired VP - 9/41 Verified Impaired
03 2389	New River	1256	Alligator Harbor	Estuary	3M	Bacteria (in shellfish)	Exceeds SEAS thresholds	Medium	2008	Listed based on change in shellfish harvesting classification (downgraded from unclassified to prohibited)

1 Where a parameter was 1998 303(d) listed, the priority shown for it in the 1998 303(d) list was retained (high or low). Where a parameter was only identified as impaired under the IWR, priorites of high, medium and low were used. Waterbodies where Mercury (in fish tissue) has been identified as impaired under the IWR, have been given a medium priority and a TMDL is scheduled for 2011

2 PP - Planning Period (January, 1991 through December, 2000); VP - Verified Period (January, 1996 through June, 2003)

The Apalachicola/Chipola Verified List is based on IWR2002 Run 14.2

0062

HEARING EXHIBIT - 00000882

Apalachicola - Chipola Group 2 Basin - Northwest District - Delist List
Hydrologic Units - Apalachicola River, Chipola River

OGC Case Number	Basin Group Name	WBID	Waterbody Segment Name	Waterbody Type	Waterbody Class	1998 303(d) Parameters of Concern	Parameters Assessed Using the IWR	Comments[1] PP=Planning Period VP=Verified Period (#Exceedances/#Samples)
03 2697	Apalachicola Bay	1274	Apalachicola Bay	Estuary	2	Nutrients	Nutrients (Chla)	PP - Potentially Impaired VP - Not Impaired Chlorophyll:6 years of annual means; Range of annual means: 1 - 5.09 ug/L; Mean of annual means: 3.832 ug/L
03 2699	Apalachicola Bay	1274B	Apalachicola Bay	Estuary	2	Coliforms	Fecal Coliform	PP - 126/2832 Not Impaired VP - 79/1459 Not Impaired
03 2700	Apalachicola Bay	1274B	Apalachicola Bay	Estuary	2	Nutrients	Nutrients (Chla)	PP - Insufficient data VP - Not Impaired. Chlorophyll: 2 years of annual means; Range of annual means: 4.57-10.76 ug/L; Mean of annual means: 7.67 ug/L.
03 2701	Apalachicola River	375E	Apalachicola River	Stream	3F	Coliforms	Total Coliform	This segment is being delisted because there were sufficient data for making the planning list assessment. PP - 0/20 Not Impaired VP - 0/9 Insufficient data
03 2702	Apalachicola River	375E	Apalachicola River	Stream	3F	Coliforms	Fecal Coliform	This segment is being delisted because there were sufficient data for the making planning list assessment. PP - 0/20 Not Impaired VP - 0/9 Insufficient data
03 2703	Apalachicola River	487	Flat Creek	Stream	3F	Total Suspended Solids	Turbidity	This segment is being delisted because there were sufficient Turbidity data for making the planning list assessment. PP - 2/10 Not impaired; VP - 0/1 Insufficient data (Based upon Turbidity data)
03 2704	Apalachicola River	487	Flat Creek	Stream	3F	Turbidity	Turbidity	This segment is being delisted because there were sufficient data for making the planning list assessment. PP - 2/10 Not impaired; VP - 0/1 Insufficient data
03 2705	Apalachicola River	1109A	Equiloxic Creek	Stream	3F	Turbidity	Turbidity	This segment is being delisted because there were sufficient data for making the planning list assessment. PP- 0/29 Not Impaired VP - 0/9 Insufficient data
03 2706	Chattahoochee River/Lake Seminole	60	Lake Seminole	Lake	3F	Dissolved Oxygen	Dissolved Oxygen	This segment is being delisted because there were sufficient data for making the planning list assessment. PP - 1/32 Not Impaired VP - 1/17 Insufficient data
03 2707	Chipola River	51A	Dead Lake	Stream	3F	Coliforms	Total Coliform	PP - 0/29 Not Impaired VP - 0/20 Not Impaired
03 2708	Chipola River	51A	Dead Lake	Stream	3F	Coliforms	Fecal Coliform	PP - 1/37 Not Impaired VP - 0/20 Not Impaired
03 2709	Chipola River	51A	Dead Lake	Stream	3F	Turbidity	Turbidity	PP - 3/81 Not Impaired VP - 1/20 Not Impaired

1. PP - Planning Period (January, 1991 through December, 2000); VP - Verified Period (January, 1996 through June 2003)

Based upon IWR 14.2, December 2003

HEARING EXHIBIT - 00000883

Attachment H

HEARING EXHIBIT - 00000884

Choctawhatchee - St Andrews Group 3 Basins
Verified List

OGC Case Number	Planning Unit	WBID	Waterbody Segment Name	Waterbody Type	Waterbody Class[1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule (IWR)	Concentrations Causing Impairment[2]	Priority for TMDL Development[3]	Projected Year for TMDL Development[3]	Comments (# Exceedances/# Samples) PP=Planning Period VP=Verified Period[4]
	Choctawhatchee Bay	692	BOGGY BAYOU	ESTUARY	3M		Bactena	Exceeds DOH threshholds	Medium	2009	Beach advisones > 21 days/yr for 2002 and 2003.
	Choctawhatchee Bay	754	POQUITO BAYOU	ESTUARY	3M		Bactena	Exceeds DOH threshholds	Medium	2009	Beach advisones > 21 days/yr for 2003.
	Choctawhatchee Bay	778AC	GULF ISLAND NATIONAL SEASHORE	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisones > 21 days/yr for 2003.
	Choctawhatchee Bay	722B	ROCKY BAYOU STATE PARK	COASTAL	3M		Bactena	Exceeds DOH threshholds	Medium	2009	Beach advisones > 21 days/yr for 2002 and 2003.
	Choctawhatchee Bay	778A	CHOCTAWHATCHEE BAY	ESTUARY	2		Fecal Coliform (Shellfish Harvesting)	Exceeds SEAS threshholds	Medium	2009	PP = 35 / 1090; VP = 27 / 474. This WBID was listed because there was a downgrade in the shellfish harvesting classification (from approved to conditionally approved) for some portion of this Class II waterbody.
	Choctawhatchee Bay	778B	CHOCTAWHATCHEE BAY	ESTUARY	2	Coliforms	Fecal Coliform (Shellfish Harvesting)	Exceeds SEAS threshholds	Medium	2009	PP = 9 / 4032; VP = 4 / 453. This WBID was listed because there was a downgrade in the shellfish harvesting classification (from approved to conditionally approved) for some portion of this Class II waterbody.
	Choctawhatchee Bay	778C	CHOCTAWHATCHEE BAY	ESTUARY	2	Coliforms	Fecal Coliform (Shellfish Harvesting)	Exceeds SEAS threshholds	Medium	2009	PP = 518 / 4533; VP = 153 / 1751. This WBID was listed because there was a downgrade in the shellfish harvesting classification (from approved to conditionally approved) for some portion of this Class II waterbody.
	Choctawhatchee Bay	778CA	CHOCTAW BEACH COUNTY PARK	ESTUARY	2		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisones > 21 days/yr prior to June 30, 2004.
	Choctawhatchee Bay	843B	GARNIERS PARK	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisones > 21 days/yr for 2002 and 2003.
	Choctawhatchee River	49, 49A-F	CHOCTAWHATCHEE RIVER	STREAM	3F	Mercury (Based on Fish Consumption Advisory) in WBIDs 49, 49F	Mercury (in Fish Tissue)	Exceeds DOH threshhold (> 0.5 mg/kg)	Low	2011	Data verified to be within the last 7.5 years. In 2004, 26 Largemouth Bass had an average mercury concentration of 0.69 mg/kg
	Choctawhatchee River	49F	CHOCTAWHATCHEE RIVER	STREAM	3F	Coliforms	Total Coliform	>2400 colonies/100 mL	Medium	2009	PP = 13 / 36; VP = 10 / 33
	Choctawhatchee River	49F	CHOCTAWHATCHEE RIVER	STREAM	3F	Coliforms	Fecal Coliform	>400 colonies/100 mL	Medium	2009	PP = 17 / 49; VP = 15/65
	St. Andrews Bay	986	PEACH CREEK	STREAM	3F		Historic Chlorophyll	Median TP=0.007 mg/l	Medium	2009	PP = Potentially Impaired; VP = Impaired. Historcal chla = 2 ug/l for 1992-1996. For 2001 and 2002, annual means > 50% above historcal background for 2 consecutive years, with values of 5.5 ug/L and 5.3 ug/L, respectively. TP is the limiting nutrient based on a mean TN/TP ratio of 62, using 212 values.
	St. Andrews Bay	1009	WESTERN LAKE OUTLET	ESTUARY	3M		Historic Chlorophyll	Median TP=0.007 mg/l	Medium	2009	PP = Potentially Impaired; VP = Impaired Historical chla = 2 ug/l for 1993-1997. For 2000 and 2001, annual means > 50% above historcal background for 2 consecutive years, with values of 6.3 ug/L and 3.1 ug/L, respectively. TP is the limiting nutrient based on a mean TN/TP ratio of 32, using 320 values.

06:5
HEARING EXHIBIT - 00000885

Choctawhatchee - St Andrews Group 3 Basins
Verified List

OGC Case Number	Planning Unit	WBID	Waterbody Segment Name	Waterbody Type	Waterbody Class[1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule (IWR)	Concentrations Causing Impairment[2]	Priority for TMDL Development[3]	Projected Year for TMDL Development[3]	Comments (# Exceedances/# Samples) PP=Planning Period VP=Verified Period[4]
	St. Andrews Bay	1265	DIRECT RUNOFF TO BAY	STREAM	2		Fecal Coliform	>400 colonies/100 mL	Medium	2009	PP = 51 / 301; VP = 19 / 87
	St. Andrews Bay	1061A	WEST BAY	ESTUARY	2		Historic Chlorophyll	Median TN= 0.31 mg/l Median TP= 0.018 mg/l	Medium	2009	PP = Potentially Impaired; VP = Impaired. Historical chla=3.6918 ug/l for 1994-1998. For 2002-2003, annual means > 50% above historical background for 2 consecutive years in 2002 and 2003, with values of 6.2 ug/L and 6.5 ug/L, respectively. Co-limiting nutrients based on a mean TN/TP ratio of 20, using 265 values.
	St. Andrews Bay	1061BB	CARL GRAY PARK	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2001, 2002 and 2003.
	St. Andrews Bay	1061BB	CARL GRAY PARK	COASTAL	3M		Fecal Coliform	>400 colonies/100 mL	Medium	2009	PP = 13 / 44; VP = 30 / 131
	St. Andrews Bay	1061CB	BEACH DRIVE	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2002 and 2003.
	St. Andrews Bay	1061EB	DELWOOD	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2002 and 2003.
	St. Andrews Bay	1061F	EAST BAY (E)	ESTUARY	2		Fecal Coliform (Shellfish Harvesting)	Exceeds SEAS threshholds	Medium	2009	PP = 270 / 2799; VP = 73 / 1188. This WBID was listed because there was a downgrade in the shellfish harvesting classification for some portion of this Class II waterbody.
	St. Andrews Bay	1061FB	DUPONT BRIDGE	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2002 and 2003.
	St. Andrews Bay	1267C	ST. JOE BAY MONUMENT BEACH	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2001, 2002, and 2003.
	St. Andrews Bay	8012B	LAGUNA BEACH	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2003.
	St. Andrews Bay	8012C	PANAMA CITY BEACH CITY PIER	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2003.
	St. Andrews Bay	8013A	BID-A-WEE BEACH	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2003.
	St. Andrews Bay	8013B	BECKRICH ROAD	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2003.
	St. Andrews Bay	8015A	8TH STREET	COASTAL	3M		Bacteria	Exceeds DOH threshholds	Medium	2009	Beach advisories > 21 days/yr for 2003.
	Choctawhatchee - St Andrews	8999	Gulf Coast	COASTAL	3M	Mercury (Based on Fish Consumption Advisory) in WBID 778C	Mercury (in Fish Tissue)	Exceeds DOH threshhold (> 0.5 mg/kg)	Low	2011	Data verified to be within the last 7.5 years. Confirmed recent data for coastal fish advisory for King Mackerel, Shark, Spotted Seatrout, Little Tunny, Cobia, Greater Amberjack, Bluefish, Crevalle Jack, Gafftopsail catfish. This includes the following WBIDs:722B, 778A, 778AB, 778AC, 778B, 778C, 778D, 843B, 1061BB, 1061CB, 1061EB, 1061FB, 1267A, 1267B, 1267C, 8008, 8008A, 8008B, 8008C, 8008D, 8008E, 8009, 8009A, 8010, 8010A, 8010B, 8010C, 8011, 8011A, 8011B, 8012, 8012A, 8012B, 8012C, 8013, 8013A, 8013B, 8013C, 8013D, 8014, 8015, 8015A, 8015B, 8015C, 8015D, 8015E, 8016, and 8017.

066

HEARING EXHIBIT - 00000886

Choctawhatchee - St Andrews Group 3 Basins
Verified List

OGC Case Number	Planning Unit	WBID	Waterbody Segment Name	Waterbody Type	Waterbody Class[1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule (IWR)	Concentrations Causing Impairment[2]	Priority for TMDL Development[3]	Projected Year for TMDL Development[3]	Comments (# Exceedances/# Samples) PP=Planning Period VP=Verified Period[4]

[1] Florida's waterbody classifications are defined as: 1 - Potable water supplies, 2 - Shellfish propagation or harvesting, 3F - Recreation, propagation, and maintenance of a healthy, well-balanced population of fish and wildlife in fresh water, 3M - Recreation, propagation, and maintenance of a healthy, well-balanced population of fish and wildlife in marine waters, 4 - Agricultural water supplies, 5 - Navigation, utility, and industrial use.

[2] "ln H+" means the natural logarithm of total hardness expressed as mg/L of CaCO3. For metals criteria involving equations with hardness, the hardness shall be set as 25 mg/L if actual hardness is < 25mg/L and set at 400 mg/L if actual hardness is > 400 mg/L. The concentration causing impairment for nutrient listings is the median.

[3] Priority and schedule for this WBID reflects the priority established for the WBID in the 1998 303(d) list. Where a parameter was 1998 303(d) listed, the priority shown for it in the 1998 303(d) list was retained if it was originally high or changed to medium if it was originally low. In the case of mercury, the priority remains low. Where a parameter was only identified as impaired under the IWR, priorities of high, medium, or low were used.

[4] PP - Planning Period (January 1, 1992 through December 31, 2001); VP - Verified Period (January 1, 1997 through June 30, 2004)

Choctawhatchee Basin / St. Andrews Basin Verified List based on IWR Run 17.

DEP
HEARING EXHIBIT - 00000887

Choctawhatchee Group 3 Basin
Delist List

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class[1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule (IWR)	Comments (#Exceedances/#Samples) PP=Planning Period; VP=Verified Period[2]
	Choctawhatchee Bay	692	BOGGY BAYOU	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 4 / 57; VP = 6 / 102
	Choctawhatchee Bay	778B	CHOCTAWHATCHEE BAY	ESTUARY	2	Coliforms	Fecal Coliform	PP = 9 / 1032; VP = 4 / 453
	Choctawhatchee Bay	778B	CHOCTAWHATCHEE BAY	ESTUARY	2	Coliforms	Total Coliform	PP = 0 / 15; VP = 1 / 18. Sufficient data in the planning period to support delisting.
	Choctawhatchee Bay	778C	CHOCTAWHATCHEE BAY	ESTUARY	2	Coliforms	Fecal Coliform	PP = 518 / 4482; VP = 154 / 1764
	Choctawhatchee Bay	778C	CHOCTAWHATCHEE BAY	ESTUARY	2	Coliforms	Total Coliform	PP = 4 / 74; VP = 3 / 51
	Choctawhatchee Bay	778C	CHOCTAWHATCHEE BAY	ESTUARY	2	Turbidity	Turbidity	PP = 7 / 4521; VP = 6 / 1959
	Choctawhatchee Bay	778D	CHOCTAWHATCHEE BAY	ESTUARY	2	Dissolved Oxygen	Dissolved Oxygen	PP = 2 / 252; VP = 2 / 165
	Choctawhatchee Bay	778D	CHOCTAWHATCHEE BAY	ESTUARY	2	Nutrients	Nutrients (chl a)	PP - No chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 2.95 - 6.25 ug/L. VP - No chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 2.95 - 7.02 ug/L. The annual means from 1997-2002 were 4.75, 2.96, 6.17, 6.22, 6.26, and 7.02 ug/L. 167 TN values, median 0.43 mg/L. 167 TP values, median 0.023 mg/L.
	Choctawhatchee Bay	906	JOES BAYOU	ESTUARY	3M	Nutrients	Nutrients (chl a)	PP - No chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 5.03 - 8.09 ug/L. VP - No ch a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 5.03 - 8.09 ug/L. The annual means from 1997-2003 were 6.7, 8.09, 5.0, 5.14, 5.03, 5.1, and 5.91 ug/L. 78 TN values, median 0.35 mg/L. 97 TP values, median 0.019 mg/L.
	Choctawhatchee Bay	917	INDIAN BAYOU	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 2 / 50; VP = 3 / 73
	Choctawhatchee Bay	917	INDIAN BAYOU	ESTUARY	3M	Nutrients	Nutrients (chl a)	PP - No chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 5.025 - 5.4 ug/L. VP - No chl a annual means exceeded 11 ug/L. Chla annual mean values ranged from 5.025 - 5.4 ug/L. The annual means from 1999-2003 were 5.03, 5.4, 5.0, 5.0, and 5.16 ug/L. 112 TN values, median 0.3105 mg/L. 120 TP values, median 0.02 mg/L.

888
HEARING EXHIBIT - 00000888

Choctawhatchee Group 3 Basin
Delist List

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class[1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule (IWR)	Comments (#Exceedances/#Samples) PP=Planning Period; VP=Verified Period[2]
	Choctawhatchee River	49	CHOCTAWHATCHEE RIVER	STREAM	3F	Coliforms	Total Coliform	PP = 1 / 20, Not Impaired; VP = 4 / 10, Insufficient Data. Delist based on data from the Planning Period.
	Choctawhatchee River	49F	CHOCTAWHATCHEE RIVER	STREAM	3F	Nutrients	Nutrients (chl a)	PP - No chl a annual means exceeded 20 ug/L. Chl a annual mean values ranged from 1.10 - 1.16 ug/L. VP - No chl a annual means exceeded 20 ug/L. Chl a annual mean values ranged from 1.10 - 1.28 ug/L. The annual means from 2000-2002 were 1.10, 1.16, and 1.28 ug/L, respectively. 61 TN values, median 0.8 mg/L. 61 TP values, median 0.068 mg/L.
	Choctawhatchee River	49F	CHOCTAWHATCHEE RIVER	STREAM	3F	Turbidity	Turbidity	VP = 9/56. 9 values out of 56 that were more than 29 NTUs above 34.9 NTUs (with a background turbidity of 5.9 NTUs).
	St. Andrews Bay	1053	DIRECT RUNOFF TO BAY	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 1 / 409; VP = 1 / 253
	St. Andrews Bay	1110	CALLOWAY BAYOU	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 4 / 142; VP = 0 / 26
	St. Andrews Bay	1136	WATSON BAYOU	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 29 / 80; VP = 4 / 27
	St. Andrews Bay	1172	PITTS BAY	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 5 / 173; VP = 0 / 48
	St. Andrews Bay	1267	ST. JOSEPH BAY	ESTUARY	2	BOD	BOD	Median BOD = 1.23 mg/L (less than screening value of 2.1 mg/L). Dissolved oxygen not impaired. PP = 73 / 2085; VP = 69 / 1097
	St. Andrews Bay	1267	ST. JOSEPH BAY	ESTUARY	2	Chlorides	Chlorides	PP = No Data; VP = 0 / 26. Not 10% above background.
	St. Andrews Bay	1267	ST. JOSEPH BAY	ESTUARY	2	Coliforms	Fecal Coliform	PP = 85 / 3125; VP = 18 / 1215. Shellfish downgrade was due to administrative reasons.
	St. Andrews Bay	1267	ST. JOSEPH BAY	ESTUARY	2	Coliforms	Total Coliform	PP = 1 / 1; VP = 0 / 30. Shellfish downgrade was due to administrative reasons.
	St. Andrews Bay	1267	ST. JOSEPH BAY	ESTUARY	2	Nutrients	Nutrients (chl a)	PP - No annual chl a means data. VP - No annual means exceeded 11 ug/L. Chl a annual mean for 2002 was 2.70 ug/l.

[1] 1 - Potable water supplies, **2** - Shellfish propogation or harvesting, **3F** - Recreation, propagation, and maintenance of a healthly, well-balanced population of fish and wildlife in fresh water, **3M** - Recreation, propagation, and maintenance of a healthly, well-balanced population of fish and wildlife in marine waters

[2] **PP** - Planning Period (January, 1992 through December, 2001);**VP** - Verified Period (January, 1997 through June 30, 2004)

Assessment Results Are Based on IWR Run 17

069

HEARING EXHIBIT - 00000889

Attachment I

HEARING EXHIBIT - 00000890

Pensacola (Group 4) - Verified List
Hydrologic Unit: Pensacola

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class [1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule	Concentration Causing Impairment [2]	Priority for TMDL Development [3]	Projected Year for TMDL Development [3]	Comments PP=Planning Period VP=Verified Period (#Exceedances/#Samples) [4]
06-0581	Blackwater River	23	ROCK CREEK	STREAM	3F	Mercury - Fish	Mercury (in fish tissue)	Exceeds DOH threshold (> 0.43 mg/Kg)	Low	2011	Data verified to be within the last 7.5 years. In 2003-2004, 19 Largemouth Bass from Woodbine Springs/ Rock Creek had an average mercury concentration of 2.33 mg/Kg
06-0582	Blackwater River	24	BLACKWATER RIVER	STREAM	3F		Mercury (in fish tissue)	Exceeds DOH threshold (> 0.43 mg/Kg)	Low	2011	Data verified to be within the last 7.5 years. In 2004, 21 Largemouth Bass had an average mercury concentration of 0.72 mg/Kg
06-0583	Blackwater River	176	POND CREEK	STREAM	3F		Fecal Coliform	>400 colonies / 100 ml	Medium	2012	pp = 87 / 470; vp = 84 / 462
06-0584	Blackwater River	176	POND CREEK	STREAM	3F		Total Coliform	>2400 colonies / 100 ml	Medium	2012	pp = 46 / 447; vp = 63 / 453
06-0585	Blackwater River	24A	BLACKWATER RIVER	STREAM	3F	Coliforms	Fecal Coliform	>400 colonies / 100 ml	Low	2011	pp = 33 / 259; vp = 45 / 357
06-0586	Blackwater River	24A-D	BLACKWATER RIVER	STREAM	3F	Mercury - Fish	Mercury (in fish tissue)	Exceeds DOH threshold (> 0.43 mg/Kg)	Low	2011	Data verified to be within the last 7.5 years. In 2004, 21 Largemouth Bass had an average mercury concentration of 0.72 mg/kg.
06-0587	Escambia River	10A-G	ESCAMBIA RIVER	STREAM	3F		Mercury (in fish tissue)	Exceeds DOH threshold (> 0.43 mg/Kg)	Low	2011	Data verified to be within the last 7.5 years. In 2004, 19 Largemouth Bass had an average mercury concentration of 0.57 mg/kg.
06-0588	Escambia River	10F	ESCAMBIA RIVER	STREAM	3F	Coliforms	Fecal Coliform	>400 colonies / 100 ml	Low	2011	pp = 35 / 270; vp = 47 / 381
06-0589	Pensacola Bay	676	CARPENTER CREEK	STREAM	3F	Coliforms	Fecal Coliform	>400 colonies / 100 ml	Low	2011	pp = 32 / 92; vp = 21 / 73
06-0590	Pensacola Bay	676	CARPENTER CREEK	STREAM	3F	Coliforms	Total Coliform	>2400 colonies / 100 ml	Low	2011	pp = 23 / 94; vp = 22 / 76
06-0591	Pensacola Bay	738	TEXAR BAYOU	ESTUARY	3M	Coliforms	Fecal Coliform	>400 colonies / 100 ml	Low	2011	pp = 68 / 471; vp = 68 / 437
06-0592	Pensacola Bay	846	BAYOU CHICO	ESTUARY	3M	Coliforms	Fecal Coliform	>400 colonies / 100 ml	High	2006	pp = 14 / 51; vp = 15 / 62
06-0593	Pensacola Bay	846	BAYOU CHICO	ESTUARY	3M	Coliforms	Total Coliform	>2400 colonies / 100 ml	High	2006	pp = 13 / 51; vp = 15 / 62
06-0594	Pensacola Bay	915	SANTA ROSA SOUND	ESTUARY	2		Fecal Coliform (Shellfish Harvesting)	>400 colonies / 100ml and exceeds SEAS thresholds	Medium	2012	pp = 89 / 785; vp = 109 / 869. This WBID was also listed because there was a downgrade in the shellfish harvesting classification (from approved to conditionally approved) for some portion of this Class 2 waterbody
06-0595	Pensacola Bay	548A	ESCAMBIA BAY (N)	ESTUARY	3M	Nutrients	Nutrients (Historic Chlorophyll)	TN=0.67 mg/L TP=0.035 mg/L	High	2006	pp = Chl a annual means = 14.7 ug/L for 1993, 5.5 ug/L for 1994, 6.0 ug/L for 2000, 8.6 ug/L for 2001, and 9.7 ug/L for 2002. No annual means exceeded the historic minimum of 4.0 ug/L by more than 50%. vp = Chl a annual means =6.0 ug/L for 2000, 8.7 ug/L for 2001, 9.7 ug/L for 2002, 5.8 ug/L for 2003, and 7.9 ug/L for 2004. The annual mean chl a values exceeded the historic minimum (of 4.0 ug/L for the years 1975-1979) by more than 50% in two consecutive years (2001 and 2002). Co-limited based on median TN/TP ratio of 15, using 38 values.

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HEARING EXHIBIT - 00000891

Pensacola (Group 4) - Verified List
Hydrologic Unit: Pensacola

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class [1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule	Concentration Causing Impairment [2]	Priority for TMDL Development [3]	Projected Year for TMDL Development [3]	Comments PP=Planning Period VP=Verified Period (#Exceedances/#Samples) [4]
06-0596	Pensacola Bay	548AB	FLORIDATOWN PARK	COASTAL	3M		Nutrients (Chlorophyll)	TN=0.91 mg/L TP=0.056 mg/L	Medium	2012	pp = Two chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 7.0 - 12.8 ug/L. vp = Four chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 7.0 - 13.4 ug/L. The annual means from 1998 - 2004 were 12.76, 10.40, 6.96, 8.86, 12.23, 13.43, and 11.69 ug/L. 22 TN values, median 0.704 ug/L. 22 TP values, median 0.0355 ug/L. Co-limited based on median TN/TP ratio of 19.98, using 22 values.
06-0597	Pensacola Bay	548BB	BAY BLUFFS PARK	COASTAL	3M		Bacteria	Exceeds SEAS thresholds	Medium	2012	Beach advisories > 21 days/yr for 2003.
06-0598	Pensacola Bay	548FB	NAVY POINT	COASTAL	3M		Bacteria	Exceeds SEAS thresholds	Medium	2012	Beach advisories > 21 days/yr for 2001-2004.
06-0599	Pensacola Bay	548FB	NAVY POINT	COASTAL	3M		Fecal Coliform	>400 colonies / 100 ml	Medium	2012	pp = 52 / 483; vp = 77 / 571
06-0600	Pensacola Bay	548H	EAST BAY	ESTUARY	2		Nutrients (Historic Chlorophyll)	TN=0.49 mg/L TP=0.03 mg/L	Medium	2012	pp = Chl a annual means = 5.1 ug/L for 1999, 5.1 ug/L for 2000, 5.1 ug/L for 2001, and 7.6 ug/L for 2002. No annual means exceeded the historic minimum of 3.5 ug/L by more than 50%. vp = Chl a annual means = 5.1 ug/L for 1999, 5.1 ug/L for 2000, 5.1 ug/L for 2001, 7.6 ug/L for 2002, 5.5 ug/L for 2003, and 5.1 ug/L for 2004. The annual mean chl a values exceeded the historic minimum (of 3.5 ug/L for the years 1974-1978) by more than 50% in two consecutive years (2002 and 2003). Co-limited based on median TN/TP ratio of 14.6, using 32 values.
06-0601	Pensacola Bay	548H	EAST BAY	ESTUARY	2		Total Coliform	>2400 colonies / 100 ml	Medium	2012	pp = 46 / 289; vp = 51 / 391
06-0602	Pensacola Bay	738AB	BAYVIEW PARK PIER	COASTAL	3M		Bacteria	Exceeds SEAS thresholds	Medium	2012	Beach advisories > 21 days/yr for 2002 - 2003.
06-0603	Pensacola Bay	738AB	BAYVIEW PARK PIER	COASTAL	3M		Fecal Coliform	>400 colonies / 100 ml	Medium	2012	pp = 16 / 80; vp = 46 / 204
06-0604	Pensacola Bay	846A	JONES CREEK	STREAM	3F	Coliforms	Fecal Coliform	>400 colonies / 100 ml	Low	2011	pp = 20 / 37; vp = 13 / 39
06-0605	Pensacola Bay	846A	JONES CREEK	STREAM	3F	Coliforms	Total Coliform	>2400 colonies / 100 ml	Low	2011	pp = 16 / 37; vp = 14 / 39
06-0606	Pensacola Bay	846B	JACKSON CREEK	STREAM	3F	Dissolved Oxygen (mg/l)	Dissolved Oxygen	< 5 mg/L	Low	2011	pp = 10 / 30, vp = 15 / 36. DO met the verification threshold of the IWR, and nitrogen is the causative pollutant. 43 TN values, with a median of 2.13 mg/L. 43 TP values, with a median of 0.056 mg/L. 39 BOD values, with a median of 0.7 mg/L.
06-0607	Pensacola Bay	846B	JACKSON CREEK	STREAM	3F	Coliforms	Fecal Coliform	>400 colonies / 100 ml	Low	2011	pp = 16 / 31, vp = 15 / 38
06-0608	Pensacola Bay	846B	JACKSON CREEK	STREAM	3F	Coliforms	Total Coliform	>2400 colonies / 100 ml	Low	2011	pp = 12 / 31; vp = 17 / 37
06-0609	Pensacola Bay	846CB	BAYOU CHICO BEACH	COASTAL	3M		Bacteria	Exceeds DOH thresholds	Medium	2012	Beach advisories > 21 days/yr for 2001-2004.

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HEARING EXHIBIT - 00000892

Pensacola (Group 4) - Verified List
Hydrologic Unit: Pensacola

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class [1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule	Concentration Causing Impairment [2]	Priority for TMDL Development [3]	Projected Year for TMDL Development [3]	Comments PP=Planning Period VP=Verified Period (#Exceedances/#Samples) [4]
06-0610	Pensacola Bay	846CB	BAYOU CHICO BEACH	COASTAL	3M		Nutrients (Chlorophyll)	TN=0.91 mg/L TP=0.063 mg/L	Medium	2012	pp = Two chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 8.5 - 21.5 ug/L. vp = Three chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 7.2 - 21.5 ug/L. The annual means from 1998 - 2004 were 16.17, 10.71, 8.51, 21.53, 9.88, 11.67, and 7.21 ug/L. 25 TN values, median 0.79 ug/L. 25 TP values, median 0.04 ug/L. Co-limited based on median TN/TP ratio of 14.7, using 25 values.
06-0611	Pensacola Bay	846CB	BAYOU CHICO BEACH	COASTAL	3M		Fecal Coliform	>400 colonies / 100 ml	Medium	2012	pp = 76 / 420, vp = 123 / 576
06-0612	Pensacola Bay	848DA	SANDERS BEACH	COASTAL	3M		Bactena	Exceeds DOH thresholds	Medium	2012	Beach advisones > 21 days/yr for 2001-2004.
06-0613	Pensacola Bay	848DA	SANDERS BEACH	COASTAL	3M		Fecal Coliform	>400 colonies / 100 ml	Medium	2012	pp = 10 / 77, vp = 30 / 201
06-0614	Pensacola Bay	915A	WOODLAWN BEACH	COASTAL	3M		Bacteria	Exceeds DOH thresholds	Medium	2012	Beach advisories > 21 days/yr for 2004
06-0615	Pensacola Bay	915B	NAVARRE PARK HWY 98	COASTAL	3M		Bactena	Exceeds DOH thresholds	Medium	2012	Beach advisones > 21 days/yr for 2004.
06-0616	Pensacola Bay	915C	LIZA JACKSON PARK	COASTAL	3M		Bacteria	Exceeds DOH thresholds	Medium	2012	Beach advisories > 21 days/yr for 2003-2004
06-0617	Pensacola Bay	915D	MARLER PARK	COASTAL	3M		Bactena	Exceeds DOH thresholds	Medium	2012	Beach advisones > 21 days/yr for 2003-2004.
06-0618	Yellow River	30	YELLOW RIVER	STREAM	3F	Coliforms	Fecal Coliform	>400 colonies / 100 ml	Low	2011	pp = 25 / 152, vp = 23 / 148
06-0619	Yellow River	35	POND CREEK	STREAM	3F		Fecal Coliform	>400 colonies / 100 ml	Medium	2012	pp = 12 / 48, vp = 7 / 26
06-0620	Yellow River	160B	SHOAL RIVER	STREAM	3F		Fecal Coliform	>400 colonies / 100 ml	Medium	2012	pp = 12 / 45, vp = 12 / 34
06-0621	Yellow River	160B	SHOAL RIVER	STREAM	3F		Total Coliform	>2400 colonies / 100 ml	Medium	2012	pp = 5 / 42, vp = 6 / 31
06-0622	Yellow River	30, 30A-30E	YELLOW RIVER	STREAM	3F	Mercury - Fish	Mercury (in fish tissue)	Exceeds DOH threshold (> 0.43 mg/Kg)	Low	2011	Data verified to be within the last 7.5 years. In 2004, 18 Largemouth Bass had an average mercury concentration of 0.69 mg/kg.
06-0623	Pensacola	8999	GULF COAST	COASTAL / ESTUARY	3M	Mercury - Fish	Mercury (in fish tissue)	Exceeds DOH threshold (> 0.43 mg/Kg)	Low	2011	Data verified to be within the last 7.5 years. Confirmed coastal fish advisory for King Mackerel and the Bull Shark. 87 King Mackerel averaged 0.67 mg/Kg in 2002. This includes the following WBIDs: 502, 548A, 548AB, 548B, 548BB, 548C, 548CB, 548CC, 548D, 548E, 548F, 548FB, 548G, 548H, 738, 738AB, 8002, 8002A, 8003, 8003D, 8003E, 8004, 8004B, 8004C, 8005, 8006, 8006A, 8007, 8007A, 833, 846, 846CB, 848DA, 915, 915A, 915B, 915C, 915D, 915E, 915F, 987.

[1] Florida's waterbody classifications are defined as: 1 - Potable water supplies, 2 - Shellfish propagation or harvesting, 3F - Recreation, propagation, and maintenance of a healthy, well-balanced population of fish and wildlife in fresh water, 3M - Recreation, propagation, and maintenance of a healthy, well-balanced population of fish and wildlife in marine waters, 4 - Agricultural water supplies, 5 - Navigation, utility, and industrial use.

[2] The nutrient concentrations represent the 75th percentiles of data from the Verified Period. The target nutrient concentration used in the subsequent TMDL will be determined during the TMDL process.

[3] Priorities and schedule for TMDL development are only provided for waters in Category 5. Priorities set under the EPA Consent Decree were retained. Medium priority is used for newly listed waters identified unde

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HEARING EXHIBIT - 00000893

Pensacola (Group 4) - Verified List
Hydrologic Unit: Pensacola

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class [1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule	Concentration Causing Impairment [2]	Priority for TMDL Development [3]	Projected Year for TMDL Development [3]	Comments PP=Planning Period VP=Verified Period (#Exceedances/#Samples) [4]

[4] Planning Period (PP) - 1/1/1993 to 12/31/2002; Verified Period (VP) - 1/1/1998 to 6/30/2005

The Verified List is based on IWR Run 22

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HEARING EXHIBIT - 00000894

Pensacola (Group 4) - Delist List
Hydrologic Unit: Pensacola

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class [1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule	Comments (#Exceedances/#Samples) PP=Planning Period VP=Verified Period [2]
06-0399	Blackwater River	18	BIG COLDWATER CREEK	STREAM	3F	Coliforms	Fecal Coliform	PP = 49 / 400; VP = 53 / 453
06-0400	Blackwater River	18	BIG COLDWATER CREEK	STREAM	3F	Coliforms	Total Coliform	PP = 32 / 391; VP = 39 / 441
06-0401	Blackwater River	19	BIG JUNIPER CREEK	STREAM	3F	Coliforms	Fecal Coliform	PP = 6 / 51; VP = 3 / 29
06-0402	Blackwater River	19	BIG JUNIPER CREEK	STREAM	3F	Coliforms	Total Coliform	PP = 3 / 44; VP = 3 / 27
06-0403	Blackwater River	19	BIG JUNIPER CREEK	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 1 / 64; VP = 0 / 30
06-0404	Blackwater River	11A	WEST FORK	STREAM	3F	Coliforms	Fecal Coliform	PP = 6 / 37; VP = 6 / 39
06-0405	Blackwater River	11A	WEST FORK	STREAM	3F	Coliforms	Total Coliform	PP = 2 / 34; VP = 3 / 38
06-0406	Blackwater River	18A	EAST FORK	STREAM	3F	Coliforms	Fecal Coliform	PP = 4 / 37; VP = 5 / 28
06-0407	Blackwater River	18A	EAST FORK	STREAM	3F	Coliforms	Total Coliform	PP = 3 / 34; VP = 3 / 27
06-0408	Blackwater River	24A	BLACKWATER RIVER	STREAM	3F	Coliforms	Total Coliform	PP = 16 / 257; VP = 26 / 356.
06-0409	Blackwater River	24D	BLACKWATER RIVER	STREAM	3F	Coliforms	Total Coliform	PP = 0 / 23.
06-0410	Escambia River	5	PINE BARREN CREEK	STREAM	3F	Coliforms	Fecal Coliform	PP = 6 / 55; VP = 2 / 30
06-0411	Escambia River	5	PINE BARREN CREEK	STREAM	3F	Coliforms	Total Coliform	PP = 0 / 51; VP = 0 / 30
06-0412	Escambia River	5	PINE BARREN CREEK	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 2 / 56; VP = 1 / 30
06-0413	Escambia River	7	CANOE CREEK	STREAM	3F	Coliforms	Fecal Coliform	PP = 7 / 50; VP = 4 / 29
06-0414	Escambia River	7	CANOE CREEK	STREAM	3F	Coliforms	Total Coliform	PP = 2 / 50; VP = 3 / 30
06-0415	Escambia River	10C	ESCAMBIA RIVER	STREAM	3F	Coliforms	Fecal Coliform	PP = 8 / 110; VP = 12 / 112
06-0416	Escambia River	10C	ESCAMBIA RIVER	STREAM	3F	Coliforms	Total Coliform	PP = 1 / 84; VP = 2 / 65
06-0417	Escambia River	10C	ESCAMBIA RIVER	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 8 / 147; VP = 9 / 128
06-0418	Escambia River	10D	ESCAMBIA RIVER	STREAM	3F	Coliforms	Fecal Coliform	PP = 12 / 114; VP = 8 / 110
06-0419	Escambia River	10D	ESCAMBIA RIVER	STREAM	3F	Coliforms	Total Coliform	PP = 1 / 95; VP = 1 / 63
06-0420	Escambia River	10D	ESCAMBIA RIVER	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 6 / 149; VP = 4 / 123
06-0425	Escambia River	10E	ESCAMBIA RIVER	STREAM	3F	Coliforms	Fecal Coliform	PP = 0 / 14; VP = 0 / 19
06-0426	Escambia River	10F	ESCAMBIA RIVER	STREAM	3F	Coliforms	Total Coliform	PP = 23 / 267; VP = 39 / 367
06-0427	Escambia River	10F	ESCAMBIA RIVER	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 2 / 202; VP = 2 / 219
06-0428	Pensacola Bay	539	MULATTO BAYOU	ESTUARY	3M	Nutrients	Chlorophyll	PP = Insufficient data; VP = No chl a annual means exceeded 11 ug/L. Chl a annual mean value for 2004 was 8.016 ug/L. 16 TN values, median 0.6995 ug/L. 16 TP values, median 0.04 ug/L.
06-0429	Pensacola Bay	694	TROUT BAYOU	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 1 / 89; VP = 3 / 75
06-0430	Pensacola Bay	694	TROUT BAYOU	ESTUARY	3M	Coliforms	Fecal Coliform	PP = 0 / 167; VP = 0 / 99

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HEARING EXHIBIT - 00000895

Pensacola (Group 4) - Delist List
Hydrologic Unit: Pensacola

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class [1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule	Comments (#Exceedances/#Samples) PP=Planning Period VP=Verified Period [2]
06-0431	Pensacola Bay	701	EAST RIVER BAY	STREAM	3F	Coliforms	Fecal Coliform	PP = 6 / 63; VP = 8 / 80
06-0432	Pensacola Bay	701	EAST RIVER BAY	STREAM	3F	Coliforms	Total Coliform	PP = 3 / 44; VP = 3 / 33
06-0433	Pensacola Bay	701	EAST RIVER BAY	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 0 / 69; VP = 0 / 80
06-0434	Pensacola Bay	738	TEXAR BAYOU	ESTUARY	3M	Coliforms	Total Coliform	PP = 42 / 462; VP = 47 / 432
06-0435	Pensacola Bay	740	BAYOU GRANDE	ESTUARY	3M	Coliforms	Fecal Coliform	PP = 4 / 35; VP = 4 / 30
06-0436	Pensacola Bay	740	BAYOU GRANDE	ESTUARY	3M	Coliforms	Total Coliform	PP = 2 / 37; VP = 3 / 31
06-0437	Pensacola Bay	846	BAYOU CHICO	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 1 / 49; VP = 2 / 61. 61 TN values, with a median of 1.33 mg/L. 63 TP values, with a median of 0.038 mg/L. 68 BOD values, with a median of 1.6 mg/L.
06-0438	Pensacola Bay	548A	ESCAMBIA BAY (N)	ESTUARY	3M	Nutrients	Chlorophyll	PP = One chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 5.5 - 14.7 ug/L. VP = No chl a annual means exceeded 11 ug/L. Chl a annual mean values ranged from 5.822 - 9.718 ug/L. The annual means from 2000 - 2003 were 6.039, 9.418, 9.718, and 5.822 ug/L. 38 TN values, median 0.625 ug/L. 39 TP values, median 0.038 ug/L. May move to delist list pending further analysis of TN data.
06-0439	Pensacola Bay	548A	ESCAMBIA BAY (N)	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 13 / 581; VP = 20 / 476. 38 TN values, with a median of 0.65 mg/L. 100 TP values, with a median of 0.0117 mg/L. 43 BOD values, with a median of 1.5 mg/L.
06-0440	Pensacola Bay	548A	ESCAMBIA BAY (N)	ESTUARY	3M	Coliforms	Total Coliform	PP = 0 / 40; VP = 0 / 31
06-0441	Pensacola Bay	548A	ESCAMBIA BAY (N)	ESTUARY	3M	Turbidity (NTU)	Turbidity	PP = 2 / 1006; VP = 0 / 502
06-0442	Pensacola Bay	548AB	FLORIDATOWN PARK	COASTAL	3M		Fecal Coliform	PP = 48 / 411; VP = 48 / 463
06-0443	Pensacola Bay	548B	ESCAMBIA BAY (S)	ESTUARY	3M	Nutrients	Chlorophyll	PP = Insufficient data; VP = No chl a annual means exceeded 11 ug/L. Chl a annual mean value for 2003 was 4.937 ug/L. 18 TN values, median 0.626 ug/L. 18 TP values, median 0.04 ug/L.
06-0444	Pensacola Bay	548B	ESCAMBIA BAY (S)	ESTUARY	3M	Dissolved Oxygen	Dissolved Oxygen	PP = 15 / 728; VP = 26 / 614. 18 TN values, with a median of 0.626 mg/L. 26 TP values, with a median of 0.025 mg/L. 15 BOD values, with a median of 1.3 mg/L.
06-0445	Pensacola Bay	548B	ESCAMBIA BAY (S)	ESTUARY	3M	Turbidity (NTU)	Turbidity	PP = 9 / 1313; VP = 8 / 770

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HEARING EXHIBIT - 00000896

Pensacola (Group 4) - Delist List
Hydrologic Unit: Pensacola

OGC Case Number	Planning Unit	WBID	Waterbody Segment	Waterbody Type	Waterbody Class [1]	Parameters Included on the 1998 303(d) List	Parameters Assessed Using the Impaired Waters Rule	Comments (#Exceedances/#Samples) PP=Planning Period VP=Verified Period [2]
06-0446	Pensacola Bay	548E	PENSACOLA BAY (MOUTH)	ESTUARY	3M	Nutrients	Chlorophyll	PP = No data; VP = No chl a annual means exceeded 11 ug/L. Chl a annual mean value for 2003 was 6.618 ug/L. 25 TN values, median 0.437 ug/L. 25 TP values, median 0.02 ug/L.
06-0447	Pensacola Bay	548E	PENSACOLA BAY (MOUTH)	ESTUARY	3M	Turbidity (NTU)	Turbidity	PP = 0 / 7; VP = 0 / 40
06-0448	Pensacola Bay	8003D	SABINE YACHT AND RACKET	COASTAL	3M		Total Coliform	PP = 0 / 15; VP = 0 / 10
06-0449	Pensacola Bay	846A	JONES CREEK	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 0 / 37; VP = 0 / 39
06-0450	Pensacola Bay	846B	JACKSON CREEK	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 0 / 32; VP = 0 / 38
06-0451	Yellow River	30	YELLOW RIVER	STREAM	3F	Coliforms	Total Coliform	PP = 10 / 121; VP = 9 / 97
06-0452	Yellow River	30	YELLOW RIVER	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 6 / 195; VP = 2 / 154
06-0453	Yellow River	30A	YELLOW RIVER	STREAM	3F	Dissolved Oxygen	Dissolved Oxygen	PP = 6 / 112; VP = 7 / 110. 110 TN values, with a median of 0.395 mg/L. 111 TP values, with a median of 0.019 mg/L. 15 BOD values, with a median of 0.5 mg/L.
06-0454	Yellow River	30A	YELLOW RIVER	STREAM	3F	Turbidity (NTU)	Turbidity	PP = 4 / 116; VP = 3 / 109

[1] Florida's waterbody classifications are defined as: **1** - Potable water supplies, **2** - Shellfish propagation or harvesting, **3F** - Recreation, propagation, and maintenance of a healthy, well-balanced population of fish and wildlife in fresh water, **3M** - Recreation, propagation, and maintenance of a healthy, well-balanced population of fish and wildlife in marine water, **4** - Agricultural water supplies, **5** - Navigation, utility, and industrial use.

[2] **PP** - Planning Period (January 1, 1993 through December 31, 2002); **VP** - Verified Period (January 1, 1998 through June 30, 2005)

Delist List is based on IWR Run 22.

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HEARING EXHIBIT - 00000897

Attachment J

HEARING EXHIBIT - 00000898

Climate Registry Cost Estimate

1) Initial Registration Fee $6000
2) Historical Data Reporting Fee (25% of Registration Fee) = $1500
Total First Year Registration Fee = $7500

HEARING EXHIBIT - 00000899

Submit by Email | Print Form

The Climate Registry

Statement of Intent Form

_____ will participate in The Climate Registry.

We will:

- Inventory and report entity-wide direct and indirect greenhouse gas (GHG) emissions, according to the guidance provided by The Climate Registry (the Registry).
- Verify our emissions through a Registry approved verifier.
- Report our total emissions through the Registry's online reporting software.

Signed: _____

Name: _____

Title: _____

Address: _____

_____

Phone: _____

Email: _____

Date: ____/____/20____

Organization's Annual Revenue/Budget:
(Check to determine annual fee)*

Annual Revenue/Budget
- ☐ Over $2 billion
- ☐ $500 million - $2 billion
- ☐ $100 million - $500 million
- ☐ $20 million - $100 million
- ☐ Under $20 million

Organization Type
- ☐ Academic
- ☐ Commercial/Industrial
- ☐ Government
- ☐ Non-profit

1st year of data to be reported for verification
- ☐ 2008
- ☐ 2009
- ☐ Prior year**_____

Official Contact for the Registry

Name: _____

Title: _____

Address: _____

_____

Phone: _____

Email: _____

Technical Contact (if different from Official)

Name: _____

Title: _____

Address: _____

_____

Phone: _____

Email: _____

Return to:
The Climate Registry, P.O. Box 712545, Los Angeles, CA 90071 or Fax to 213-623-6716

HEARING EXHIBIT - 00000900

The Climate Registry

*Annual Fee Structure

Commercial and Industrial Organizations with Revenues:

Over $2 billion	$10,000
From $500 million - $2 billion	$6,000
From $100 million - $500 million	$3,500
From $20 million - $100 million	$1,700
Under $20 million	$600

Non-profit, Government and Academic Organizations with Budgets:

Over $2 billion	$5,000
From $500 million - $2 billion	$3,500
From $100 million - $500 million	$2,500
From $20 million - $100 million	$850
Under $20 million	$450

**Reporting Historic Data: Reporters may choose any year to begin reporting historical data, as long as they report consecutive years of data up through the year in which they join the Registry

- **To report 1-3 years of historical data**: One time fee of 25 percent of a Reporter's annual reporting fee
- **To report 4 or more years of historical data**: One time fee of 50 percent of a Reporter's annual reporting fee

Please provide a 100-word (or less) description of your organization:

Return to:
The Climate Registry, P.O. Box 712545, Los Angeles, CA 90071 or Fax to 213-623-6716

HEARING EXHIBIT - 00000901

STATEMENTS OF INCOME

For the Years Ended December 31, 2007, 2006, and 2005

Gulf Power Company 2007 Annual Report

	2007	2006	2005
		(in thousands)	
Operating Revenues:			
Retail revenues	**$1,006,329**	$952,038	$864,859
Wholesale revenues --			
Non-affiliates	**83,514**	87,142	84,346
Affiliates	**113,178**	118,097	91,352
Other revenues	**56,787**	46,637	43,065
Total operating revenues	**1,259,808**	1,203,914	1,083,622
Operating Expenses:			
Fuel	**573,354**	534,921	415,789
Purchased power --			
Non-affiliates	**11,994**	16,288	29,995
Affiliates	**59,499**	57,536	68,402
Other operations	**201,768**	192,375	176,620
Maintenance	**68,672**	67,144	73,150
Depreciation and amortization	**85,613**	89,170	85,002
Taxes other than income taxes	**82,992**	79,808	76,387
Total operating expenses	**1,083,892**	1,037,242	925,345
Operating Income	**175,916**	166,672	158,277
Other Income and (Expense):			
Interest income	**5,348**	5,228	3,804
Interest expense, net of amounts capitalized	**(44,680)**	(44,133)	(40,317)
Other income (expense), net	**(1,502)**	(3,185)	(813)
Total other income and (expense)	**(40,834)**	(42,090)	(37,326)
Earnings Before Income Taxes	**135,082**	124,582	120,951
Income taxes	**47,083**	45,293	44,981
Net Income	**87,999**	79,289	75,970
Dividends on Preferred and Preference Stock	**3,881**	3,300	761
Net Income After Dividends on Preferred and Preference Stock	**$ 84,118**	$ 75,989	$ 75,209

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

HEARING EXHIBIT - 00000902

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Gulf's Response to Staff's Third Request for Production of Documents (No. 6)

6. Referring to the testimony of Susan Ritenour dated April 4, 2008, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Schedule 8E attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

ANSWER:

In accordance with FPSC Order No. PSC-94-0044-FOF-EI, the rate of return used to develop the revenue requirements of ECRC investment is based on the capital structure and cost rates approved in Gulf's last rate case, Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI, dated June 10, 2002.

Gulf Power Company
Environmental Cost Recovery Clause
Calculation of Revenue Requirement Rate of Return

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Notes:
(1) Capital Structure Approved by FPSC on April 26, 2002 in Doc. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on April 26, 2002 in Doc. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

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Gulf's response to Staff's First Set of Interrogatories (Nos. 1 -3)

1. Please refer to Gulf's petition filed August 28, 2009, page 7, regarding SPCC's 2009 projections for capital expenditures of $25,000, and refer to Exhibit SDR-3, page 3 of 87, line 1.20 - SPCC Compliance. Please reconcile the amount shown in the petition with the total shown in Exhibit SDR-3 ($128,006).

ANSWER:

The $25,000 as stated in Gulf's petition and shown on Exhibit SDR-3, page 23 of 87 (Line 1a of Schedule 4P, Page 20), represents total expenditures and placed-in-service for the SPCC Compliance Program in 2009. The $128,006 on Exhibit SDR-3, page 3 of 87, line 1.20 – SPCC Compliance represents total 2009 revenue requirements for the entire SPCC Compliance program.

This program includes two projects: PE 1272 – Crist Switchyard Stormwater (a previously approved project) and PE 1401 – Plant Smith SPCC Compliance (a new project). For 2009, PE 1272 has no projected expenditures. The 2009 revenue requirements for PE's 1272 and 1401 are $125,105 and $2,901 respectively.

2. Please refer to Gulf's petition filed August 28, 2009, page 7, regarding SPCC's 2009 projections for O&M expenditures of $5,000, and refer to Exhibit SDR-3, page 2 of 87. Please state where the O&M expenditures are shown in Exhibit SDR-3.

ANSWER:

The $5,000 in O&M expenses for the SPCC Program is included in Exhibit SDR-3, page 2 of 87, Line Item 1.11 – General Solid and Hazardous Waste.

3. Please refer to Gulf's petition filed August 28, 2009, page 7, regarding Plant Crist Water Conservation Project 2009 projections for capital expenditures of 17.4 million, and refer to Exhibit SDR-3, page 3 of 87, line 1.24 - Crist Water Conservation. Please reconcile the amount shown in the petition with the total shown in Exhibit SDR-3 ($35,571).

ANSWER:

The $17.4 million [(1)], as stated in the Gulf's petition, represents the total projected expenditures for the Plant Crist Water Conservation Project. For 2009, total expenditures and placed-in-service amounts for the project are projected to be $1.3 million as shown on Exhibit SDR-3, page 27 of 87 (Line 1a of Schedule 4P, Page 24). The $35,571 on Exhibit SDR-3, page 3 of 87, line 1.24 – Crist Water Conservation represents the demand portion of the total revenue requirements of $38,538 for the entire program.

This program is made up of two projects, PE 1227 and PE 1298. PE 1227 is a previously approved Plant Crist Water Conservation project that consisted of installing level controls on the fire water tanks during 2006. PE 1298 is a new Plant Crist Water Conservation project to utilize reclaimed water from a local wastewater treatment plant. For 2009, PE 1227 has no projected expenditures. The 2009 revenue requirements for PE's 1227 and 1298 are $12,745 and $25,793 respectively.

(1) The $17.4 million included in the petition inadvertently omitted AFUDC of approximately $0.5 million. This amount has been corrected in Section F (Company Specific Issues) in Gulf's position on Issue 3 in our Prehearing Statement.

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TECO's Response to Staff's Second Request for Production of Documents (No. 2)

HEARING EXHIBIT - 00000910

2. Please provide workpapers (break down into line items) to support the Company's estimate of $15,000 - $150,000 O&M expenses for 2009.

A. The high-level estimate range was developed through telephone conversations with members of other Florida utilities. It includes, minimally, the fees to join the Climate Registry pursuant to the website, www.theclimateregistry.org as well as anticipated costs for establishing an infrastructure for data collection, reporting and third party verification of greenhouse gas emissions as required by House Bill 7135 ("HB 7135").

Attached is a preliminary, non-binding quote that Tampa Electric received to establish a Compliance Management System to track GHG. Once the Florida Department of Environmental Protection has finished reviewing HB 7135 and has established a rule and official start date Tampa Electric will have a better understanding of the compliance requirements and will be able to provide more definitive program details and costs. Although this quote includes other aspects of air emissions monitoring beyond GHG, at such time Tampa Electric files with the Commission a GHG program, the company will only request cost recovery for those expenditures specifically related to GHG and will take the steps to bid out the necessary work needed to comply with the rule and HB 7135.

HEARING EXHIBIT - 00000911

MALCOLM PIRNIE

INDEPENDENT ENVIRONMENTAL ENGINEERS, SCIENTISTS AND CONSULTANTS

Malcolm Pirnie, Inc.
1300 E. 8th Avenue, Suite F100
Tampa, FL 33605
T: 813.248.6900 F: 813.248.8085
www.pirnie.com

April 9, 2008

Mr. Byron T. Burrows, P.E., BCEE
Manager, Air Programs
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601-0111

Re: Request for Proposal
Tampa Electric Company
Bayside Power Station
Compliance Management System and Enviance System Configuration
Title V Air Permitting, Air Emissions Inventory, and Greenhouse Gas Management

Dear Mr. Burrows:

Malcolm Pirnie appreciates the opportunity to provide the Tampa Electric Company (TEC) with this proposal to further develop their Enviance® compliance management system with respect to Title V Air Permitting, Air Emission Inventory, and Greenhouse Gas (GHG) Management at its Bayside Power Station.

This proposal is being written at the request of TEC following our February 21, 2008 meeting at TEC's training facility in Tampa in which Malcolm Pirnie provided an overview demonstration of the Enviance® system that included Title V permitting and reporting at TEC's Big Bend, Bayside, Polk, and Phillips Power Stations. Our demonstration also included GHG and TRI applications which TEC could utilize in their recordkeeping and reporting at these facilities.
The scope for this proposal was further defined during our conference call held on March 28, 2008.

Based on these discussions, Malcolm Pirnie understood that TEC's ultimate goals for the expansion of the Enviance® system with respect to air program compliance include:

- Track milestones, deadlines, requirements, and compliance items associated with environmental regulations at its powers stations.
- Provide task notifications and calendaring to support the successful completion of compliance items at its power stations.
- Perform data compilations and calculations associated with the preparation of Annual Operating Reports (AORs).
- The automation of weekly emissions reports generated from CEMS data for internal review.
- Verification of compliance for Annual Compliance Certification Reports.
- Data tracking and creation of deviation reports.
- Data integration into the Enviance® system to allow this system to function as a data repository so that information can be pulled out and reported in tables or graphs (for trending analysis) for both internal use and externally as required for reporting purposes.
- GHG management and tracking with respect to but not limited to the following: development of baseline emissions, future emissions tracking, measurement of performance, and association of costs with GHG management and tracking efforts.
- To provide a system that is easily manageable by internal TEC personnel.

As we discussed in our March 28, 2008 conference call, TEC would like to initially configure the Enviance® system for Title V Permitting and Air Emissions Inventory at its Bayside Power Station. The configuration of the Bayside Power Station for air compliance will provide TEC with a complete air permitting "template" that can be used as a guide by TEC personnel to build out and configure the system for the other power stations. For expansion of the Title V and emission inventory configuration to the other three sites, Malcolm Pirnie can provide training to allow for TEC personnel to perform these configurations.

At TEC's request, this proposal is written in three sections, with a section addressing each of the following: Title V Permitting, Air Emissions Inventory, and GHG Management.

Scope of Work

Title V Permitting

The Bayside Power Station is an electric power plant consisting of combined cycle gas turbine units. The facility also generates emissions at its F.J. Gannon Station Fuel Yard from activities including the transfer and storage of coal via railcar, truck, and barge.

A full Title V Environmental Compliance solution, which provides a centralized relational database with task and event notification, tracking, and reporting will be created for the Bayside Power Station. Each and every requirement from the Title V permit will be configured in the system. Malcolm Pirnie will convert the requirements of the Title V permit into active objects within the system, including tasks, data inputs, calculations, emissions limits tracking, log books, permit deviations documentation, and compliance tracking.

The scope of this proposal is based on the Bayside Power Station Title V Permit numeric and non-numeric requirements as outlined in the excel spreadsheet named *Bayside Title V Limits & Compliance Summary* provided to Malcolm Pirnie via email on March 3, 2008 and the Title V permit dated January 1, 2005.
Malcolm Pirnie understands that this spreadsheet may not be completely up to date with respect to current permitting conditions. Malcolm Pirnie will review the Title V permit in full and identify additional requirements (and associated tasks) that are not in the current spreadsheet. These identified requirements will be included in the configuration scope. Based on our cursory review of the Compliance Summaries and Title V Air permits we estimate there are approximately 50 numeric and 50 non-numeric requirements for the Bayside facility.

Project Planning, Data Collection, and Solution Design

Malcolm Pirnie proposes to conduct a one-day project kickoff and data collection workshop at TEC's office in Tampa, Florida. The purpose of the data collection workshop is to define and document the specific details and decisions related to the layout and configuration of the environmental compliance solution. Based on the information gathered prior to and during the workshop and follow-up communications, Malcolm Pirnie will prepare for TEC's review and comment a data collection worksheet (DCW). The DCW will allow the project team to jointly review and approve the conceptual solution prior to the configuration of requirements in the Enviance® system.

After review of the DCW and incorporation of project team comments, TEC and Malcolm Pirnie will sign off on the DCW prior to initiation of the Configuration phase. Changes to the DCW may be necessary

during the course of the project as additional information becomes available. The project team will review any potential changes to determine their impact on the overall solution as well as on the project scope, schedule, and budget. Changes approved by the project team will be documented and incorporated into the DCW.

Configuration

Once TEC signs off on the DCW, Malcolm Pirnie will begin the configuration of the Title V Air Permitting solution. During configuration, TEC will have access to the system to review the progress of the configuration. Malcolm Pirnie will conduct internal solution testing during configuration to evaluate the results against the DCW. At the completion of the Configuration phase, Malcolm Pirnie will perform solution testing of the entire solution and evaluate it against success criteria contained in the DCW as well as project scope for completeness. TEC will have the opportunity to evaluate the system configuration. If deficiencies are found with respect to the fulfillment of the DCW, then Malcolm Pirnie will work with TEC to address them. Once the configuration is deemed complete, the project will move into the deployment phase.

Deployment and Training

Malcolm Pirnie will provide up to 8 TEC end user personnel with one day of on-site training. The objective of the training will be to train key TEC staff on the use of the Title V Permitting solution. At the conclusion of the training and sign off of this phase, TEC will have on-going use of a live Title V Permitting solution. Malcolm Pirnie will provide ongoing adoption support to assist TEC with usage of the system after the training period.

Schedule

Malcolm Pirnie expects delivery of the complete Title V Permitting system within one to two months from notice to proceed. This is dependent on the availability of integral TEC personnel and accuracy of the data needed to configure the solution. Malcolm Pirnie is prepared to begin work immediately upon authorization to proceed.

Cost

Malcolm Pirnie will deliver the Title V Permitting solution for a total lump sum fee of $30,000 which includes all expenses. The table below provides a breakdown of these costs:

Task Description	Cost
Title V Permit Review	$3,000
Kickoff Meeting & Data Collection Workshop	$4,500
Data Collection Worksheet	$4,500
System Configuration	$14,500
Training	$3,500
TOTAL	$30,000

Air Emissions Inventory

This section of the proposal covers the Enviance® system configuration to facilitate the required air emissions calculations and associated reporting for the Bayside Power Station. The system will be configured to perform emission inventory calculations and generate the associated required annual emission report. Configuration of the emission inventory calculations will include all required raw data inputs (i.e., emission factors, fuel usage, material throughput, etc.), calculation definition (i.e., monthly calculations, rolling 12-month average calculations and annual summaries) and output parameters. This information will be identified based on previously generated spreadsheets, used by TEC, that are currently used for this purpose.

The tasks described previously for the Title V Permitting effort will be employed for this effort, with the exception of the permit review. Malcolm Pirnie will deliver, in approximately one month from notice to proceed, the Air Emissions Inventory solution for a total lump sum fee of $23,500 which includes all expenses. The table below provides a breakdown of these costs:

Task Description	Cost
Kickoff Meeting & Data Collection Workshop	$4,500
Data Collection Worksheet	$4,500
System Configuration	$11,000
Training	$3,500
TOTAL	$23,500

Greenhouse Gas Management

TEC is extremely interested in developing a GHG management system. TEC is a member of the Chicago Climate Exchange and are eager to develop a cost-effective, streamlined GHG management system that will incorporate the essential tools to initially allow for the establishment of baseline emissions, followed by emission and performance tracking, and reporting. Malcolm Pirnie will configure the Enviance® system to meet TEC's regulatory need to establish a current GHG "footprint" that can be supported by a credible emissions inventory that is complete and accurate and can withstand rigorous third-party auditing and verification. Ultimately, TEC's Enviance® system can be configured to meet various GHG protocols for reporting emissions across a wide range of programs such as:

- Voluntary GHG reduction programs
- GHG registries
- National and regional industry initiatives
- GHG trading programs
- Sector-specific protocols developed by a number of industry associations

The direct (Scope 1) and indirect (Scopes 2 and 3) emissions must be determined. Other important considerations in developing the inventory of emissions are the company's options for reducing GHG emissions and how the company can shape its carbon footprint to maximize its cost savings opportunities and minimize its risks. The development of an emissions inventory will support development of GHG management strategies will allow TEC to identify the following:

MALCOLM PIRNIE

- Their GHG emissions profile
- Where reductions might be possible
- Whether they may need to buy carbon credits

For the purposes of this proposal, the Bayside Power Station will be the first facility included in the emission inventory. Malcolm Pirnie understands that TEC is very motivated to complete a corporate wide GHG inventory and the development of the GHG inventory for the Bayside facility will be an important step in providing a streamlined process that can be used for the other facilities, service centers, and for other potential sources of indirect emissions. The GHG solution will be able to leverage integration and data collection from existing programs (i.e., Title V implementation) to generate the GHG emissions inventory. Our scope for the development of a GHG management Enviance® system configuration is listed below.

Kickoff Meeting and Data Collection

Malcolm Pirnie proposes to conduct a one-day project kickoff and data collection workshop at TEC's office in Tampa, Florida. The purpose of the data collection workshop is to outline all GHG sources and to define and document the specific details and decisions related to the layout and configuration of the environmental compliance solution. Enviance® has a GHG template complete with typical Scope 1, 2, and 3 sources and conversion factors based on the World Resources Institute (WRI) standard. This template can be used by TEC as a starting point in determining the Baseline emissions for their direct and indirect sources at the Bayside Power Station. During the workshop, Malcolm Pirnie will work with TEC personnel to determine the:

- Sources of GHG sources
- Available data that tracks GHG emissions (e.g. fuel source and usage)
- Data gaps and how they can be filled

The Baseline emissions are the calculated amount of GHG emissions for the designated baseline year. TEC will be able to compare future GHG emissions to this Baseline to show reductions and/or as a basis for carbon trading. The Inventory and Baseline will include direct and indirect GHG emissions from the Bayside Power Plant facility.

Based on the information gathered prior to and during the workshop and follow-up communications, the emissions inventory will be developed and provided to TEC for their review, comment, and approval. Malcolm Pirnie will incorporate the emissions inventory into a DCW and submit to TEC for review and comment. The DCW will allow the project team to jointly review and approve the conceptual solution prior to the configuration of requirements in the Enviance® system.

Solution Design and Configuration

Once the Emissions Inventory solution design has been approved by TEC, Malcolm Pirnie will calculate the annual emissions of GHGs for each source to create the Baseline. All GHG emissions will be converted into CO_2 equivalents for reporting purposes.

The State of Florida has joined The Climate Registry. The Climate Registry is a multi-state and tribe collaboration aimed at developing and managing a common greenhouse gas emissions reporting system with high integrity that is capable of supporting various GHG reporting and reduction policies for its member states and tribes and reporting entities. The Climate Registry has not developed its own set of protocols yet. It will follow the California Climate Action Registry General Reporting Protocol until its

own protocol is developed.

Deployment, Reporting, and Training

The solution configuration will be designed to produce a defensible Baseline in accordance with the General Reporting Protocols to be reported to The Climate Registry. Malcolm Pirnie will provide up to 4 TEC end user personnel with one day of on-site training. The objective of the training will be to train key TECO staff on the use of the GHG solution.

Following successful determination of Baseline Emissions, Malcolm Pirnie will work with TEC in developing emissions tracking, performance measurement, and reporting solutions. Additionally, Malcolm Pirnie understands that TEC would like to use the Enviance® system as a means to associate costs with GHG efforts. The scoping of these solutions can better be determined following the development of TEC's Baseline emissions for the Bayside facility and Malcolm Pirnie can provide scope tasks and pricing at that time.

Following the training session, Malcolm Pirnie will provide ongoing adoption support to assist TEC with ongoing usage of the system.

Schedule

Malcolm Pirnie expects delivery of the complete GHG Management system within one to two months from notice to proceed. This is dependent on the availability of integral TEC personnel and accuracy of the data needed to configure the solution. Malcolm Pirnie is prepared to begin work immediately upon authorization to proceed.

Cost

Malcolm Pirnie will deliver the Title V Permitting solution for a total lump sum fee of $20,000 which includes all expenses. The table below provides a breakdown of these costs:

Task Description	Cost
Kickoff Meeting & Data Collection	$4,000
Development of Baseline Emissions	$4,000
Solution Design and Configuration	$6,500
Deployment and Reporting	$2,500
Training	$3,000
TOTAL	$20,000

At TEC's request Malcolm Pirnie has provided the scoping and fees for the Title V Permitting, Air Emissions Inventory, and GHG Management broken out as individual projects. We would like to provide TEC with the option of performing the three projects simultaneously, which would provide for an economy of scale by reducing travel expenses and coordination meetings. Should TEC decide to perform the projects concurrently, we would be able to provide a cost savings of $5,000 off of the summation of project costs resulting in a total fee of $68,500.

MALCOLM PIRNIE

Team and Experience

David Cibik, Senior Project Engineer in the Tampa office will be the project manager, responsible for the day-to-day progress of the project. The configuration of the TEC's Enviance® system will be performed by Tampa-based staff with support from our Buffalo office. Malcolm Pirnie will coordinate and facilitate all necessary communications with Enviance®. Due to our extensive experience with architecture and configuration of the Enviance® system, we will execute the project independent of direct involvement with Enviance® staff.

If you have any questions regarding this proposal, please contact me at (813) 242-7210. We appreciate this opportunity to provide TEC with these environmental services.

Very truly yours,

MALCOLM PIRNIE, INC.

David Cibik, P.E., R.E.M.
Senior Project Engineer

ACCEPTANCE:

Tampa Electric Company

Name

Title

Date

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TECO's Response to Staff's Fourth Request for Production of Documents (No. 4)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)	**DOCKET NO. 080007-EI**
	)	**FILED: OCTOBER 2, 2008**
	)	

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FOURTH REQUEST FOR

PRODUCTION OF DOCUMENTS (NO. 4)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (No. 4) propounded and served on September 12, 2008, by the Florida Public Service Commission Staff.

HEARING EXHIBIT - 00000920

4. Please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-4P attached to the testimony of Howard Bryant, filed August 29, 2008. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

A. The following schedule shows the derivation of the debt and equity components for lines 7(a) and (b) on Form 42-4P.

Last FPSC Capital Structure and Cost Rates
Based on 11.75% ROE

	Amount ($)	Ratio (%)	Cost Rate (%)	Weighted Cost (%)
Long Term Debt	558,899	30.08	7.81	2.35
Short Term Debt	56,194	3.02	5.37	0.16
Preferred Stock	45,539	2.45	6.49	0.16
Customer Deposits	43,512	2.34	7.86	0.18
Common Equity [1]	801,028	43.12	11.75	5.07
Deferred ITC - Weighted Cost	59,035	3.18	10.01	0.32
Accumulated Deferred Income Taxes & Zero Cost ITCs	293,667	15.81	0.00	0.00
Total	**1,857,874**	**100.00**		**8.2392**

[1] Effective January 1, 1995 per FPSC Order No. PSC-95-0580-FOF-EI, Docket No. 950379-EI.

HEARING EXHIBIT - 00000921

ITC split between Debt and Equity:

	Amount ($)	Ratio (%)
Long Term Debt	558,899	39.77
Equity - Preferred	45,539	3.24
Equity - Common	801,028	56.99
Total	**1,405,466**	**100.00**

Deferred ITC - Weighted Cost:

Debt	=.32% * 39.77%	0.13%
Equity	=.32% * 60.23%	0.19%
	Weighted Cost	**0.32%**

Total Equity Cost Rate:

Preferred Stock	0.16%
Common Equity	5.07%
Deferred ITC - Weighted Cost	0.19%
Total	5.42%
Tax Multiplier	1.628002
Total Equity Component	**8.8238%**

Total Debt Cost Rate:

Long Term Debt	2.35%
Short Term Debt	0.16%
Customer Deposits	0.18%
Deferred ITC - Weighted Cost	0.13%
Total Debt Component	**2.82%**

HEARING EXHIBIT - 00000922

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TECO's response to Staff's First Set of Interrogatories (Nos. 1 - 2)

HEARING EXHIBIT - 00000923

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)))	DOCKET NO. 080007-EI FILED: JULY 28, 2008

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1-2)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 1-2) propounded and served on June 26, 2008, by the Florida Public Service Commission.

HEARING EXHIBIT - 00000924

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
INDEX TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-2)

Number	Witness	Subject	Bates Stamped Page
1	Bryant	In its response to No. 1 of PSC staff's Audit Request 11 FAC, Tampa Electric Company (the Company) stated "At the time Tampa Electric began the utilization of the FGD System on Big Bend Units 1 & 2, it was determined that 25% of the incremental payroll was used for specific Scrubber operations. Therefore, the Company began allocating 25% of the incremental payroll to the Big Bend FGD Units 1&2 project which is recovered through the ECRC."	1
2	Bryant	In its response to No. 3 of PSC staff's Audit Request 11 FAC, the Company stated "the Big Bend Unit 2 neural network system, projects L6377 and L7477, was retired due to loss of functionality. A evaluation is under way to determine future actions."	3

Howard T. Bryant
Manager, Rates

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

1. In its response to No. 1 of PSC staff's Audit Request 11 FAC, Tampa Electric Company (the Company) stated "At the time Tampa Electric began the utilization of the FGD System on Big Bend Units 1 & 2, it was determined that 25% of the incremental payroll was used for specific Scrubber operations. Therefore, the Company began allocating 25% of the incremental payroll to the Big Bend FGD Units 1&2 project which is recovered through the ECRC."

   a. Please explain whether the Commission or the Company made the decision.

   b. If the decision was made by the Commission, please provide the Order Number.

   c. Please state which year the payroll allocation started.

A. On May 15, 1998, Tampa Electric petitioned the Florida Public Service Commission for approval of its FGD system on Big Bend Units 1 and 2 for cost recovery through the ECRC. On September 2, 1998, the Commission conducted a hearing on the matter and in Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999, ECRC approval was granted.

The FGD system began commercial operation in December 1999. In anticipation of its operation, Tampa Electric determined the FGD system's ECRC projected expenditures as part of the normal process to identify all 2000 projected costs for ECRC recovery. Consistent with the testimony of Tampa Electric witness Don Pless filed in Docket No. 980693-EI, the company's 2000 ECRC projection filing submitted in Docket No. 990007-EI on October 1, 1999 contained O&M costs for four new, incremental operating employees necessary to operate the FGD system. The capital and O&M costs for the FGD system, including the four new positions, were approved in Order No. PSC-99-2513-FOF-EI, issued December 22, 1999.

Recognizing the four new employees would eventually change positions, leave for other employment or retire, the difficulty of tracking four specific individual employees for future cost allocation to the FGD system was evaluated. The FGD system required 16 total employees to maintain its

HEARING EXHIBIT - 00000926

operation. Therefore, the company determined that the four incremental employees represented 25 percent of the total work force necessary to operate the FGD system. Subsequently, Tampa Electric has utilized this method of accounting for the incremental ECRC payroll cost associated with the Big Bend Units 1 and 2 FGD system and the Commission has audited and approved those costs for ECRC recovery to date.

HEARING EXHIBIT - 00000927

2. In its response to No. 3 of PSC staff's Audit Request 11 FAC, the Company stated "the Big Bend Unit 2 neural network system, projects L6377 and L7477, was retired due to loss of functionality. A evaluation is under way to determine future actions." Please describe or explain:

   a. Details of the projects L6377 and L7477;

   b. How the Scrubber Unit 2 maintains its normal performance without the neural network on line;

   c. What is the Company's plan to replace or repair the neural network;

   d. When does the Company expect the problem will be solved;

   e. Regarding the neural network of the Unit 1 Scrubber, has the Company conducted any re-training/ updating of the neural network to improve its function since it was placed on-line;

   f. Has the Company considered using modern artificial intelligence technologies, such as the fuzzy neural network or evolutionary neural network, to replace the retired and/or existing neural network(s) to improve the performance and efficiency of the Scrubber(s)?

A. a. Tampa Electric entered into a Consent Decree ("CD") with the United States Environmental Protection Agency in February 2000. Two initial requirements of the CD focused on NO_x emissions reductions. First, the company was required to implement technologies that would provide early NO_x reductions through commercially available combustion optimization methods, and second, the company was required to explore and demonstrate innovative NO_x control technologies that would be generating unit specific. Big Bend Neural Network Combustion Optimization, project L7477, was initiated in December 2000 as part of early CD efforts to reduce NO_x emissions on Big Bend Unit 2. The neural network system was purchased from Pegasus with the intent of improving combustion and reducing the amount of NO_x produced in the combustion process. While Tampa Electric was engaged with Pegasus to install and tune the operations of the neural network, Pegasus developed a method to optimize sootblowing operations.

HEARING EXHIBIT - 00000928

The optimization was designed to further reduce NO_x emissions as well as maintenance and operating costs while improving boiler efficiency. Therefore, Big Bend Neural Network Sootblowing Optimization, project L6377, was initiated in May 2002 as part of the innovative NO_x abatement CD requirement.

Testing of these technologies was completed in early 2006. Shortly thereafter, Pegasus was purchased by Neuco, another neural network supplier, and Neuco made a decision to not support the Pegasus technology. Subsequent to the non-support decision by Neuco, Tampa Electric elected to continue the operation and tuning of the neural network system and the sootblowing technology; however, it became apparent that without manufacturer support the equipment could not be maintained at its optimal performance level. Therefore, the company discontinued its use mid 2006 and contracted with another manufacturer for neural network systems.

b. Big Bend Unit 2 scrubber operations are not effected by the neural network system. The intent of the neural network is to lower NO_x production while the scrubber mitigates SO_x production.

c. In 2007, Tampa Electric installed a neural network system on Big Bend Unit 4 and initiated plans to install a system on Big Bend Unit 3 in 2008. This is a critical step in that the neural network is performing well on Unit 4, but Unit 3 is a different type of boiler. Therefore, once the neural network has been installed on Unit 3 and the test results for that unit and its boiler configuration become available, Tampa Electric will determine the cost-effectiveness of installing neural network systems on Big Bend Units 1 and 2 which are the same boiler types as Unit 3.

d. As previously stated, it was not in the company's best interest to continue trying to operate the Pegasus systems without ongoing support from the manufacturer. The plan to pursue proven technology was initiated with success on Big Bend Unit 4. If the proven technology is successful with the boiler configuration on Big Bend Unit 3, Tampa Electric will continue to pursue neural network combustion optimization on Big Bend Units 1 and 2 with installations occurring in 2009 and 2010.

HEARING EXHIBIT - 00000929

e. The only operating neural network for combustion optimization is on Big Bend Unit 4. Tampa Electric's plan is to continue the sequential installation of neural network systems on the remaining three units as long as the systems prove to be useful and prudent based on each previous unit's performance. With regard to retraining the neural network system, the technology continuously updates and "retrains" the model to optimize combustion under changing boiler conditions.

f. Tampa Electric continues to pursue modern neural network systems for combustion optimization on all the Big Bend coal units. Additionally, the company monitors the technology as it applies to applications such as sootblowing optimization, scrubber operations and selective catalytic reduction operations. Tampa Electric currently has no plans to install any of these technologies except for combustion optimization, and only as long as it is cost-effective and prudent to do so.

HEARING EXHIBIT - 00000930

33

TECO's response to Staff's Second Set of Interrogatories (No. 3)

HEARING EXHIBIT - 00000931

3. Please describe, in detail, the scope of Tampa Electric Company's Greenhouse Gas ("GHG") Reduction Program.

A. The intent of Tampa Electric's GHG Reduction Program is solely to initiate voluntary data collection and reporting of GHG emissions as required by House Bill 7135 ("HB 7135"). At this time, no scope of work exists, as it is only an estimate of costs to join the Climate Registry, establish GHG inventory procedures and to establish repeatable results for third party verification.

The Florida Department of Environmental Protection is still reviewing HB 7135 in an effort to establish a rule and official start date. At that time Tampa Electric will have a better understanding of the compliance objectives and requirements.

HEARING EXHIBIT - 00000932

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TECO's response to Staff's Third Set of Interrogatories (Nos. 4 - 7)

HEARING EXHIBIT - 00000933

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)	DOCKET NO. 080007-EI
	)	FILED: OCTOBER 7, 2008
	)	

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD SET OF INTERROGATORIES (NOS. 4-7)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 4-7) propounded and served on September 17, 2008, by the Florida Public Service Commission.

HEARING EXHIBIT - 00000934

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
INDEX TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 4-7)

Number	Witness	Subject	Bates Stamped Page
4	Howard Bryant	Refer to the August 29, 2008 filing form 42-4P, p. 13 of 26, Big Bend No_x Emissions Reduction. Please explain why line 2, Plant-in-Service/Depreciation Base and Line 3, Accumulated Depreciation are added together. Please provide the correct depreciation calculations for line 8.a.	1
5	Howard Bryant	Refer to the August 29, 2008 filing form 42-4P, p. 24 of 26, Big Bend FGD system reliability. The projected numbers for line 2, Plant-in-Service/Depreciation Base, appear to be the same numbers that were used in the August 4, 2008, filing. Please verify that the numbers are correct.	2
6	Howard Bryant	Refer to the August 29, 2008 filing form 42-4P, p. 11 of 26, Big Bend Units 1 and 2 FGD, Notes (A) and (D). A depreciation rate of 2.3% is shown for account no. 312.45. Account 312.45 appears to be the account number for units 3 and 4. Please explain. If the correct rate is not being used, provide the correct depreciation calculation.	4
7	Howard Bryant	Refer to the August 29, 2008 filing form 42-4P, p. 21 of 26, Big Bend Unit 2 SCR, Notes (A) and (D). A depreciation rate of 2.4% is shown for account no. 312.44. Account 312.44 appears to be the account number for unit 4. Please explain. If the correct rate is not being used, provide the correct depreciation calculation.	23

Howard Bryant
Manager, Rates
Tampa Electric Company
702 N. Franklin St.
Tampa, FL 33602

4. Refer to the August 29, 2008 filing form 42-4P, p. 13 of 26, Big Bend No_x Emissions Reduction. Please explain why line 2, Plant-in-Service/Depreciation Base and Line 3, Accumulated Depreciation are added together. Please provide the correct depreciation calculations for line 8.a.

A. On form 42-4P, page 13 of 26, the formula in line 5 calculates Net Investment by adding Plant-in-Service, line 2, and Accumulated Depreciation, line 3. The balance in accumulated depreciation is reflected as a negative balance but due to the August 2007 retirement of plant equipment, the accumulated depreciation balance reflects a positive balance.

When retiring units, the original cost of a retired asset is credited to the plant account and debited to accumulated depreciation. The cost of retiring the asset is also debited to accumulated depreciation.

HEARING EXHIBIT - 00000936

5. Refer to the August 29, 2008 filing form 42-4P, p. 24 of 26, Big Bend FGD system reliability. The projected numbers for line 2, Plant-in-Service/Depreciation Base, appear to be the same numbers that were used in the August 4, 2008, filing. Please verify that the numbers are correct.

A. On form 42-4P, page 24 of 26, the projected numbers for line 2, Plant-in-Service/Depreciation Base, contained an inadvertent formula error. Attached is the revised form. The overall impact to the 2009 Projection filing due to the correction associated with this interrogatory is attached to the response to Interrogatory 6.

HEARING EXHIBIT - 00000937

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

Form 42-4P
Page 24 of 26
REVISED

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	$11,719,963	
3.	Less: Accumulated Depreciation	(294,511)	(317,097)	(339,683)	(362,269)	(384,855)	(407,441)	(430,027)	(452,613)	(475,199)	(497,785)	(520,371)	(542,957)	(565,543)	
4.	CWIP - Non-Interest Bearing	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	
5.	Net Investment (Lines 2 + 3 + 4)	$11,441,634	11,419,048	11,396,462	11,373,876	11,351,290	11,328,704	11,306,118	11,283,532	11,260,946	11,238,360	11,215,774	11,193,188	11,170,602	
6.	Average Net Investment		11,430,341	11,407,755	11,385,169	11,362,583	11,339,997	11,317,411	11,294,825	11,272,239	11,249,653	11,227,067	11,204,481	11,181,895	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		84,049	83,883	83,717	83,551	83,385	83,219	83,053	82,887	82,721	82,554	82,388	82,222	$997,629
	b. Debt Component (Line 6 x 2.82% x 1/12)		26,861	26,808	26,755	26,702	26,649	26,596	26,543	26,490	26,437	26,384	26,331	26,277	318,833
8.	Investment Expenses														
	a. Depreciation (C)		22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	271,032
	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)		133,496	133,277	133,058	132,839	132,620	132,401	132,182	131,963	131,744	131,524	131,305	131,085	1,587,494
	a. Recoverable Costs Allocated to Energy		133,496	133,277	133,058	132,839	132,620	132,401	132,182	131,963	131,744	131,524	131,305	131,085	1,587,494
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		128,378	128,077	127,695	127,352	127,482	127,997	127,443	126,782	127,270	126,395	126,532	127,143	1,528,546
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)		$128,378	$128,077	$127,695	$127,352	$127,482	$127,997	$127,443	$126,782	$127,270	$126,395	$126,532	$127,143	$1,528,546

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,477,493) and 312.45 ($10,242,470)
(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

3

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 5
PAGE 2 OF 2
FILED: OCTOBER 7, 2008

HEARING EXHIBIT - 00000938

6. Refer to the August 29, 2008 filing form 42-4P, p. 11 of 26, Big Bend Units 1 and 2 FGD, Notes (A) and (D). A depreciation rate of 2.3% is shown for account no. 312.45. Account 312.45 appears to be the account number for units 3 and 4. Please explain. If the correct rate is not being used, provide the correct depreciation calculation.

A. Due to an inadvertent error, the correct depreciation rate was not used to calculate the depreciation expense for a portion of the Big Bend Units 1 and 2 FGD project placed in-service in January 2007. The correct depreciation rate is 2.9% for account number 312.46e.

Tampa Electric corrected the applicable forms in the 2007 True-up, 2008 Actual/Estimated True-up files and the 2009 Projection filings. These forms are attached as well as the forms that reflect the overall impacts from the revisions associated with Interrogatory Nos. 5 and 7.

2007 True-up
- Form 42-1A
- Form 42-2A
- Form 42-3A
- Form 42-6A
- Form 42-7A
- Form 42-8A, page 11 of 26

2008 Actual/Estimated True-up
- Form 42-1E
- Form 42-2E
- Form 42-3E
- Form 42-6E
- Form 42-7E
- Form 42-8E, page 11 of 26

2009 Projection
- Form 42-1P
- Form 42-3P
- Form 42-4P, page 11 of 26
- Form 42-7P, January 2009 through April 2009
- Form 42-6P, May 2009 through December 2009
- Form 42-7P, May 2009 through December 2009

HEARING EXHIBIT - 00000939

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007
(in Dollars)

Form 42 - 1A
REVISED

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2007 to December 2007 (Form 42-2A, Lines 5 + 6 + 10)	$22,088,568
2	Estimated/Actual True-Up Amount Approved for the Period January 2007 to December 2007 (Order No. PSC-07-0922 FOF-EI)	9,624,173
3	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2009 to December 2009 (Lines 1 - 2)	$12,464,395

HEARING EXHIBIT - 00000940

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Form 42 - 2A
REVISED

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)	($5,265,935)	($4,789,886)	($4,781,167)	($4,928,971)	($5,337,681)	($5,850,945)	($6,496,394)	($6,565,988)	($7,081,686)	($6,089,819)	($5,198,503)	($4,937,115)	($67,324,090)
2.	True-Up Provision	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,852	34,738,235
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	(2,371,082)	(1,895,033)	(1,886,314)	(2,034,118)	(2,442,828)	(2,956,092)	(3,601,541)	(3,671,135)	(4,186,833)	(3,194,966)	(2,303,650)	(2,042,263)	(32,585,856)
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	823,958	1,399,886	1,248,559	(188,756)	(11,254,749)	(3,092,906)	(5,563,023)	(20,943,114)	(8,269,493)	(11,010,637)	(5,903,794)	(13,601,439)	(76,355,508)
	b. Capital Investment Projects (Form 42-7A, Line 9)	1,385,291	1,371,958	1,400,815	1,390,615	1,567,014	2,097,744	2,094,907	2,087,670	2,107,089	2,075,282	2,111,482	2,125,917	21,815,784
	c. Total Jurisdictional ECRC Costs	2,209,249	2,771,844	2,649,374	1,201,859	(9,687,735)	(995,162)	(3,468,116)	(18,855,444)	(6,162,404)	(8,935,355)	(3,792,312)	(11,475,522)	(54,539,724)
5.	Over/Under Recovery (Line 3 - Line 4c)	(4,580,331)	(4,666,877)	(4,535,688)	(3,235,977)	7,244,907	(1,960,930)	(133,425)	15,184,309	1,975,571	5,740,389	1,488,662	9,433,259	21,953,869
6.	Interest Provision (Form 42-3A, Line 10)	83,871	51,116	18,507	(11,111)	(15,060)	(16,270)	(33,571)	(13,896)	11,586	14,564	17,035	27,928	134,699
7.	Beginning Balance True-Up & Interest Provision	34,738,235	27,346,922	19,836,308	12,424,274	6,282,333	10,617,327	5,745,274	2,683,425	14,958,985	14,051,289	16,911,389	15,522,233	34,738,235
	a. Deferred True-Up from January to December 2005 Order No. PSC-xx-xxxx-FOF-EI)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)
8.	True-Up Collected/(Refunded) (see Line 2)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,852)	(34,738,235)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	15,451,239	7,940,625	528,591	(5,613,350)	(1,278,356)	(6,150,409)	(9,212,258)	3,063,302	2,155,606	5,015,706	3,626,550	10,192,885	10,192,885
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)	$15,451,239	$7,940,625	$528,591	($5,613,350)	($1,278,356)	($6,150,409)	($9,212,258)	$3,063,302	$2,155,606	$5,015,706	$3,626,550	$10,192,885	$10,192,885

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TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 6
PAGE 3 OF 19
FILED: OCTOBER 7, 2008

HEARING EXHIBIT - 00000941

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Form 42 - 3A
REVISED

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1	Beginning True-Up Amount (Form 42-2A Line 7 + 7a + 10)	$22,842,552	$15,451,239	$7,940,625	$528,591	($5,613,350)	($1,278,356)	($6,150,409)	($9,212,258)	$3,063,302	$2,155,606	$5,015,706	$3,626,550	
2	Ending True-Up Amount Before Interest	15,367,368	7,889,509	510,084	(5,602,239)	(1,263,296)	(6,134,139)	(9,178,687)	3,077,198	2,144,020	5,001,142	3,609,515	10,164,957	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	38,209,920	23,340,748	8,450,709	(5,073,648)	(6,876,646)	(7,412,495)	(15,329,096)	(6,135,060)	5,207,322	7,156,748	8,625,221	13,791,507	
4	Average True-Up Amount (Line 3 x 1/2)	19,104,960	11,670,374	4,225,355	(2,536,824)	(3,438,323)	(3,706,248)	(7,664,548)	(3,067,530)	2,603,661	3,578,374	4,312,611	6,895,754	
5	Interest Rate (First Day of Reporting Business Month)	5.27%	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.24%	5.62%	5.05%	4.72%	4.75%	
6	Interest Rate (First Day of Subsequent Business Month)	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.24%	5.62%	5.05%	4.72%	4.75%	4.98%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53%	10.52%	10.52%	10.52%	10.52%	10.54%	10.52%	10.86%	10.67%	9.77%	9.47%	9.73%	
8	Average Interest Rate (Line 7 x 1/2)	5.265%	5.260%	5.260%	5.260%	5.260%	5.270%	5.260%	5.430%	5.335%	4.885%	4.735%	4.865%	
9	Monthly Average Interest Rate (Line 8 x 1/12	0.439%	0.438%	0.438%	0.438%	0.438%	0.439%	0.438%	0.453%	0.445%	0.407%	0.395%	0.405%	
10	Interest Provision for the Month (Line 4 x Line 9)	$83,871	$51,116	$18,507	($11,111)	($15,060)	($16,270)	($33,571)	($13,896)	$11,586	$14,564	$17,035	$27,928	$134,699

HEARING EXHIBIT - 00000942

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 6
PAGE 4 OF 19
FILED: OCTOBER 7, 2008

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Form 42 - 6E
REVISED

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	$830,177	$830,177	$0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	478,165	478,165	0	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	84,822	84,822	0	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	57,574	57,574	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	94,694	94,694	0	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	6,262	6,262	0	0.0%
	g. Phillips Upgrade Tank # 4 for FDEP	9,842	9,842	0	0.0%
	h. Big Bend Unit 1 Classifier Replacement	148,910	148,910	0	0.0%
	i. Big Bend Unit 2 Classifier Replacement	107,596	107,596	0	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	14,137	14,137	0	0.0%
	k. Big Bend Units 1 & 2 FGD	9,157,941	9,156,955	986	0.0%
	l. Big Bend FGD Optimization and Utilization	2,648,825	2,648,825	0	0.0%
	m. Big Bend NO_x Emissions Reduction	843,258	866,806	(23,548)	-2.7%
	n. Big Bend PM Minimization and Monitoring	1,102,382	1,102,382	0	0.0%
	o. Polk NO_x Emissions Reduction	214,062	214,062	0	0.0%
	p. Big Bend Unit 4 SOFA	339,250	339,250	0	0.0%
	q. Big Bend Unit 1 Pre-SCR	283,729	283,636	93	0.0%
	r. Big Bend Unit 2 Pre-SCR	228,630	228,630	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	125,209	133,737	(8,528)	-6.4%
	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	0	0	0	0.0%
	w. Big Bend Unit 4 SCR	5,131,544	5,145,048	(13,504)	-0.3%
	x. Big Bend FGD System Reliability	769,057	778,808	(9,751)	-1.3%
	y. Clean Air Mercury Rule	7,913	0	7,913	0.0%
	z. SO_2 Emissions Allowances	(64,117)	(66,968)	2,851	-4.3%
2.	Total Investment Projects - Recoverable Costs	$22,619,862	$22,663,350	($43,488)	-0.2%
3.	Recoverable Costs Allocated to Energy	$22,451,490	$22,494,978	($43,488)	-0.2%
4.	Recoverable Costs Allocated to Demand	$168,372	$168,372	$0	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-06-0972-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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HEARING EXHIBIT - 00000943

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 6
PAGE 5 OF 19
FILED: OCTOBER 7, 2008

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Form 42-7A
REVISED

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	$70,024	$69,871	$69,718	$69,565	$69,411	$69,258	$69,105	$68,951	$68,798	$68,645	$68,492	$68,339	$830,177		$830,177
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	40,562	40,433	40,302	40,173	40,042	39,912	39,782	39,652	39,522	39,392	39,261	39,132	478,165		478,165
	c.	Big Bend Unit 4 Continuous Emissions Monitors	7,149	7,135	7,120	7,106	7,090	7,076	7,061	7,046	7,032	7,017	7,003	6,987	84,822		84,822
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,855	4,845	4,835	4,824	4,814	4,803	4,793	4,782	4,772	4,761	4,750	4,740	57,574	$ 57,574	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,986	7,968	7,951	7,934	7,917	7,900	7,883	7,865	7,848	7,831	7,814	7,797	94,694	94,694	
	f.	Phillips Upgrade Tank # 1 for FDEP	530	528	527	526	524	523	521	519	518	517	515	514	6,262	6,262	
	g.	Phillips Upgrade Tank # 4 for FDEP	832	830	828	825	824	821	819	817	815	812	811	808	9,842	9,842	
	h.	Big Bend Unit 1 Classifier Replacement	12,602	12,567	12,532	12,497	12,462	12,427	12,391	12,357	12,321	12,287	12,251	12,216	148,910		148,910
	i.	Big Bend Unit 2 Classifier Replacement	9,102	9,077	9,052	9,028	9,003	8,978	8,954	8,929	8,905	8,881	8,856	8,831	107,596		107,596
	j.	Big Bend Section 114 Mercury Testing Platform	1,189	1,187	1,185	1,183	1,181	1,179	1,177	1,175	1,173	1,171	1,170	1,167	14,137		14,137
	k.	Big Bend Units 1 & 2 FGD	773,671	772,003	770,043	768,084	766,125	764,166	762,206	760,247	758,288	756,329	754,369	752,410	9,157,941		9,157,941
		Big Bend FGD Optimization and Utilization	222,958	222,554	222,150	221,745	221,341	220,937	220,534	220,130	219,725	219,321	218,917	218,513	2,648,825		2,648,825
	m.	Big Bend NO_x Emissions Reduction	73,064	72,909	72,754	72,600	72,445	72,291	72,136	69,327	66,554	66,474	66,393	66,311	843,258		843,258
	n.	Big Bend PM Minimization and Monitoring	92,943	92,747	92,551	92,355	92,159	91,963	91,767	91,571	91,375	91,180	90,983	90,788	1,102,382		1,102,382
	o.	Polk NO_x Emissions Reduction	18,075	18,032	17,989	17,946	17,902	17,860	17,817	17,774	17,731	17,688	17,645	17,603	214,062		214,062
	p.	Big Bend Unit 4 SOFA	28,544	28,494	28,445	28,395	28,346	28,296	28,246	28,197	28,147	28,096	28,047	27,997	339,250		339,250
	q.	Big Bend Unit 1 Pre-SCR	21,814	24,031	23,966	23,928	23,887	23,846	23,806	23,765	23,726	23,686	23,654	23,620	283,729		283,729
	r.	Big Bend Unit 2 Pre-SCR	17,447	19,397	19,357	19,318	19,278	19,238	19,199	19,159	19,119	19,079	19,039	19,000	228,630		228,630
	s.	Big Bend Unit 3 Pre-SCR	7,225	7,552	7,865	8,214	8,249	8,246	9,484	10,732	10,757	10,809	15,576	20,500	125,209		125,209
	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	0	0	0	0	0	0	0		0
	w.	Big Bend Unit 4 SCR	0	0	0	0	169,240	704,920	709,200	711,363	712,140	709,259	707,615	707,807	5,131,544		5,131,544
	x.	Big Bend FGD System Reliability	18,024	25,414	42,726	55,199	64,410	72,680	74,416	76,434	77,949	79,256	84,667	97,882	769,057		769,057
	y.	Clean Air Mercury Rule	0	0	0	0	0	0	0	811	1,651	1,725	1,824	1,902	7,913		7,913
	z.	SO_2 Emissions Allowances (B)	(7,837)	(7,573)	(7,539)	(7,466)	(6,940)	(6,309)	(5,942)	(4,872)	(3,662)	(2,784)	(1,990)	(1,203)	(64,117)		(64,117)
2		Total Investment Projects - Recoverable Costs	1,420,759	1,430,001	1,444,357	1,453,979	1,629,710	2,171,011	2,175,355	2,176,731	2,175,204	2,171,432	2,177,662	2,193,681	22,619,862	$ 168,372	$ 22,451,490
3		Recoverable Costs Allocated to Energy	1,406,556	1,415,830	1,430,216	1,439,870	1,615,631	2,156,964	2,161,339	2,162,748	2,161,251	2,157,511	2,163,772	2,179,802	22,451,490		
4		Recoverable Costs Allocated to Demand	14,203	14,171	14,141	14,109	14,079	14,047	14,016	13,983	13,953	13,921	13,890	13,859	168,372		
5		Retail Energy Jurisdictional Factor	0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337			
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)	1,371,561	1,358,259	1,387,145	1,376,976	1,553,404	2,084,165	2,081,358	2,074,153	2,093,601	2,061,825	2,098,055	2,112,520	21,653,022		
8		Jurisdictional Demand Recoverable Costs (D)	13,730	13,699	13,670	13,639	13,610	13,579	13,549	13,517	13,488	13,457	13,427	13,397	162,762		
9		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,385,291	$1,371,958	$1,400,815	$1,390,615	$1,567,014	$2,097,744	$2,094,907	$2,087,670	$2,107,089	$2,075,282	$2,111,482	$2,125,917	$21,815,784		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Project's Total Return Component on Form 42-8A, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

Depreciation Memo Entry	325,235.82	324,429.49	327,956.27	323,412.95	387,242.98	452,278.60	451,811.31	447,013.92	448,158.15	441,891.61	448,236.21	448,236.77	4,825,904		
ROI	1,060,055	1,047,529	1,072,859	1,067,202	1,179,771	1,645,465	1,643,096	1,640,656	1,658,931	1,633,390	1,663,246	1,677,680	16,989,880		
TOTAL															

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 6
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HEARING EXHIBIT - 00000944

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Form 42-8A
Page 11 of 26
REVISED

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period AACunt	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		$1,359	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,359
	b. Clearings to Plant		234,029	0	0	0	0	0	0	0	0	0	0	0	234,029
	c. Retirements		0	0	0	0	0	0	0	0	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)	$83,318,932	$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	$83,552,961	
3.	Less: Accumulated Depreciation	(24,498,151)	(24,699,788)	(24,901,708)	(25,103,628)	(25,305,548)	(25,507,468)	(25,709,388)	(25,911,308)	(26,113,228)	(26,315,148)	(26,517,068)	(26,718,988)	(26,920,908)	
4.	CWIP - Non-Interest Bearing	232,670	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$59,053,451	58,853,173	58,651,253	58,449,333	58,247,413	58,045,493	57,843,573	57,641,653	57,439,733	57,237,813	57,035,893	56,833,973	56,632,053	
6.	Average Net Investment		58,953,312	58,752,213	58,550,293	58,348,373	58,146,453	57,944,533	57,742,613	57,540,693	57,338,773	57,136,853	56,934,933	56,733,013	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		433,494	432,015	430,530	429,045	427,561	426,076	424,591	423,106	421,622	420,137	418,652	417,167	$5,103,996
	b. Debt Component (Line 6 x 2.82% x 1/12)		138,540	138,068	137,593	137,119	136,644	136,170	135,695	135,221	134,746	134,272	133,797	133,323	1,631,188
8.	Investment Expenses														
	a. Depreciation (D)		201,637	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	2,422,757
	b. AACrtization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		773,671	772,003	770,043	768,084	766,125	764,166	762,206	760,247	758,288	756,329	754,369	752,410	9,157,941
	a. Recoverable Costs Allocated to Energy		773,671	772,003	770,043	768,084	766,125	764,166	762,206	760,247	758,288	756,329	754,369	752,410	9,157,941
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		754,422	740,612	746,853	734,534	736,617	738,375	734,000	729,104	734,553	722,786	731,458	729,186	8,832,500
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)		$754,422	$740,612	$746,853	$734,534	$736,617	$738,375	$734,000	$729,104	$734,553	$722,786	$731,458	$729,186	$8,832,500

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

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
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INTERROGATORY NO. 6
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HEARING EXHIBIT - 00000945

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2008 to December 2008
(in Dollars)

Form 42 - 1E
REVISED

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($7,910,357)
2.	Interest Provision (Form 42-2E, Line 6)	157,133
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 2008 to December 2008 (Lines 1 + 2 + 3)	($7,753,224)

HEARING EXHIBIT - 00000946

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

Form 42 - 2E
REVISED

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)	$1,638,579	$1,370,190	$1,402,163	$1,497,358	$1,604,847	$1,896,228	$1,980,000	$1,969,000	$1,970,000	$1,792,000	$1,546,000	$1,554,000	$20,220,365
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	1,790,707	1,779,707	1,780,707	1,602,707	1,356,707	1,364,713	17,948,855
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	934,271	952,608	(142,256)	828,339	63,219	999,666	(2,465,452)	(1,260,017)	(1,282,291)	(1,293,091)	(1,274,616)	(981,498)	(4,921,118)
	b. Capital Investment Projects (Form 42-7E, Line 9)	2,134,304	2,110,308	2,120,016	2,105,726	2,116,026	2,149,067	2,922,184	3,014,042	3,014,426	3,012,149	3,025,277	3,056,805	30,780,330
	c. Total Jurisdictional ECRC Costs	3,068,575	3,062,916	1,977,760	2,934,065	2,179,245	3,148,733	456,732	1,754,025	1,732,135	1,719,058	1,750,661	2,075,307	25,859,212
5.	Over/Under Recovery (Line 3 - Line 4c)	(1,619,289)	(1,882,019)	(764,890)	(1,626,000)	(763,691)	(1,441,798)	1,333,975	25,682	48,572	(116,351)	(393,954)	(710,594)	(7,910,357)
6.	Interest Provision (Form 42-3E, Line 10)	31,846	20,427	16,266	13,326	10,676	8,018	8,023	9,344	9,787	10,098	9,993	9,329	157,133
7.	Beginning Balance True-Up & Interest Provision	(2,271,510)	(3,669,660)	(5,341,959)	(5,901,290)	(7,324,671)	(7,988,393)	(9,132,880)	(7,601,589)	(7,377,270)	(7,129,618)	(7,046,578)	(7,241,246)	(2,271,510)
	a. Deferred True-Up from January to December 2007 (Order No. PSC-xx-xxxx-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	3,331,515	4,862,806	5,087,125	5,334,777	5,417,817	5,223,149	4,711,171	4,711,171
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	$3,331,515	$4,862,806	$5,087,125	$5,334,777	$5,417,817	$5,223,149	$4,711,171	$4,711,171

HEARING EXHIBIT - 00000947

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 6
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FILED: OCTOBER 7, 2008

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

Form 42 - 3E
REVISED

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)	$10,192,885	$8,794,735	$7,122,436	$6,563,105	$5,139,724	$4,576,002	$3,331,515	$4,862,806	$5,087,125	$5,334,777	$5,417,817	$5,223,149	
2.	Ending True-Up Amount Before Interest	8,762,889	7,102,009	6,546,839	5,126,398	4,565,326	3,323,497	4,854,783	5,077,781	5,324,990	5,407,719	5,213,156	4,701,842	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	18,955,774	15,896,744	13,669,275	11,689,503	9,705,050	7,899,499	8,186,298	9,940,587	10,412,115	10,742,496	10,630,973	9,924,991	
4.	Average True-Up Amount (Line 3 x 1/2)	9,477,887	7,948,372	6,834,638	5,844,752	4,852,525	3,949,750	4,093,149	4,970,294	5,206,058	5,371,248	5,315,487	4,962,496	
5.	Interest Rate (First Day of Reporting Business Month)	4.98%	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.25%	2.25%	2.25%	2.25%	2.25%	
6.	Interest Rate (First Day of Subsequent Business Month)	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.06%	6.17%	5.72%	5.47%	5.27%	4.88%	4.70%	4.50%	4.50%	4.50%	4.50%	4.50%	
8.	Average Interest Rate (Line 7 x 1/2)	4.030%	3.085%	2.860%	2.735%	2.635%	2.440%	2.350%	2.250%	2.250%	2.250%	2.250%	2.250%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.336%	0.257%	0.238%	0.228%	0.220%	0.203%	0.196%	0.188%	0.188%	0.188%	0.188%	0.188%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$31,846	$20,427	$16,266	$13,326	$10,676	$8,018	$8,023	$9,344	$9,787	$10,098	$9,993	$9,329	$157,133

HEARING EXHIBIT - 00000948

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 6
PAGE 10 OF 19
FILED: OCTOBER 7, 2008

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

Form 42 - 6E
REVISED

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	$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	8,920,859	8,915,093	5,766	0.1%
	l. Big Bend FGD Optimization and Utilization	2,590,639	2,590,639	0	0.0%
	m. Big Bend NO_x Emissions Reduction	798,805	872,714	(73,909)	-8.5%
	n. Big Bend PM Minimization and Monitoring	1,084,033	1,127,247	(43,214)	-3.8%
	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	279,624	420	0.2%
	r. Big Bend Unit 2 Pre-SCR	224,909	224,909	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	356,032	437,512	(81,480)	-18.6%
	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	5,437,189	8,778,536	(3,341,347)	-38.1%
	w. Big Bend Unit 4 SCR	8,408,013	6,125,701	2,282,312	37.3%
	x. Big Bend FGD System Reliability	1,532,141	1,549,199	(17,058)	-1.1%
	y. Clean Air Mercury Rule	70,383	119,317	(48,934)	-41.0%
	z. SO_2 Emissions Allowances	(5,743)	(9,165)	3,422	37.3%
2.	Total Investment Projects - Recoverable Costs	$32,013,152	$33,327,174	($1,314,022)	-3.9%
3.	Recoverable Costs Allocated to Energy	$31,849,280	$33,163,302	($1,314,022)	-4.0%
4.	Recoverable Costs Allocated to Demand	$163,872	$163,872	$0	0.0%

Notes:

Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-07-0922-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

HEARING EXHIBIT - 00000949

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

Form 42-7E
REVISED

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
	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	741,181	740,801	739,347	738,186	740,013	747,453	8,920,859		8,920,859
		Big Bend FGD Optimization and Utilization	218,109	217,704	217,301	216,997	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	65,943	66,072	66,495	67,263	68,079	68,642	798,805		798,805
	n.	Big Bend PM Minimization and Monitoring	90,591	90,396	90,199	90,004	89,807	89,612	89,451	89,326	89,297	90,248	92,084	93,018	1,084,033		1,084,033
	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	31,516	31,460	31,404	31,348	31,293	31,237	356,032		356,032
	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	814,499	921,572	920,503	921,937	925,601	933,077	5,437,189		5,437,189
	w.	Big Bend Unit 4 SCR	707,557	706,732	705,859	705,392	702,934	700,469	699,388	698,201	697,048	695,930	694,811	693,692	8,408,013		8,408,013
	x.	Big Bend FGD System Reliability	110,065	114,980	117,554	125,303	132,098	132,395	132,600	132,998	133,334	133,550	133,648	133,616	1,532,141		1,532,141
	y.	Clean Air Mercury Rule	1,934	3,617	5,799	6,334	6,383	6,412	6,417	6,417	6,417	6,417	6,417	7,819	70,383		70,383
	z.	SO_2 Emissions Allowances (B)	(648)	(616)	(603)	(590)	(577)	(564)	(515)	(438)	(381)	(326)	(270)	(215)	(5,743)		(5,743)
15		Total Investment Projects - Recoverable Costs	2,205,269	2,210,332	2,211,685	2,219,721	2,224,108	2,218,890	3,030,946	3,135,902	3,131,985	3,132,108	3,138,255	3,153,951	32,013,152	$ 163,872	$ 31,849,280
	3.	Recoverable Costs Allocated to Energy	2,191,441	2,196,536	2,197,921	2,205,986	2,210,406	2,205,218	3,017,305	3,122,293	3,118,408	3,118,560	3,124,740	3,140,466	31,849,280		
	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	0.9465322	0.9513098	0.9685443	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093			
	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	2,908,998	3,000,687	3,001,301	2,999,052	3,012,212	3,043,769	30,621,920		
	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	$2,922,184	$3,014,842	$3,014,426	$3,012,149	$3,025,277	$3,056,805	$30,780,330		

6.057

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Project's Total Return Component on Form 42-8E, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 6
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HEARING EXHIBIT - 00000950

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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	$4,739	$101,681	$299,643	$25,875	$78,289	$86,030	$694,484	$1,242,861	$2,533,602
	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)	$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	$83,552,961	$83,552,961	
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)	(29,142,028)	(29,343,948)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	4,739	106,420	406,063	431,938	510,227	596,257	1,290,741	2,533,602	
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	55,624,675	55,448,630	55,324,999	55,209,109	55,701,673	56,742,614	
6.	Average Net Investment		56,531,093	56,329,173	56,127,253	55,925,333	55,725,782	55,577,072	55,575,814	55,536,653	55,386,815	55,267,054	55,455,391	56,222,144	
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	408,658	408,370	407,268	406,388	407,773	413,411	$4,924,118
	b. Debt Component (Line 6 x 2.82% x 1/12)		132,848	132,374	131,899	131,425	130,956	130,606	130,603	130,511	130,159	129,878	130,320	132,122	1,573,701
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	201,920	201,920	2,423,040
	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	741,181	740,801	739,347	738,186	740,013	747,453	8,920,859
	a. Recoverable Costs Allocated to Energy		750,451	748,492	746,532	744,573	742,637	741,193	741,181	740,801	739,347	738,186	740,013	747,453	8,920,859
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	714,576	711,996	711,582	709,898	713,364	724,438	8,572,884
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	$714,576	$711,996	$711,582	$709,898	$713,364	$724,438	$8,572,884

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

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
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HEARING EXHIBIT - 00000951

Form 42 - 1P
REVISED

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2009 to December 2009

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)	$5,259,690	$334,116	$5,593,806
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	44,360,731	152,790	44,513,521
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	49,620,421	486,906	50,107,327
2. True-up for Estimated Over/(Under) Recovery for the current period January 2008 to December 2008 (Form 42-2E, Line 5 + 6 + 10)	(7,788,845)	35,621	(7,753,224)
3. Final True-up for the period January 2007 to December 2007 (Form 42-1A, Line 3)	12,596,764	(132,369)	12,464,395
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2009 to December 2009 (Line 1 - Line 2- Line 3)	44,812,502	583,654	45,396,156
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$44,844,767	$584,074	$45,428,841

Notes: Allocation to energy and demand in each period is in proportion to the respective period split of costs indicated on Lines 7 and 8 of Forms 42-5 and 42-7 of the actuals and estimates.

HEARING EXHIBIT - 00000952

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

Form 42-3P
REVISED

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	$66,346	$66,193	$66,040	$65,887	$65,733	$65,580	$65,427	$65,274	$65,121	$64,967	$64,814	$64,660	$786,042		$786,042
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	37,440	37,310	37,180	37,050	36,920	36,790	36,659	36,529	36,399	36,269	36,139	36,008	440,693		440,693
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,796	6,781	6,767	6,752	6,738	6,723	6,708	6,693	6,678	6,664	6,649	6,635	80,584		80,584
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,604	4,593	4,583	4,572	4,563	4,552	4,542	4,531	4,521	4,510	4,500	4,489	54,560	$ 54,560	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,573	7,555	7,538	7,521	7,504	7,487	7,470	7,452	7,435	7,418	7,401	7,384	89,738	89,738	
	f.	Phillips Upgrade Tank # 1 for FDEP	497	495	493	491	490	488	487	486	485	483	482	481	5,859	5,859	
	g.	Phillips Upgrade Tank # 4 for FDEP	780	778	775	773	771	768	767	764	762	760	758	755	9,214	9,211	
	h.	Big Bend Unit 1 Classifier Replacement	11,759	11,725	11,689	11,654	11,619	11,584	11,549	11,514	11,478	11,444	11,408	11,373	138,796		138,796
	i.	Big Bend Unit 2 Classifier Replacement	8,510	8,485	8,461	8,436	8,411	8,386	8,362	8,337	8,312	8,288	8,263	8,238	100,489		100,489
	j.	Big Bend Section 114 Mercury Testing Platform	1,142	1,140	1,138	1,137	1,134	1,133	1,130	1,129	1,126	1,125	1,122	1,121	13,577		13,577
	k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue	751,859	750,717	749,579	748,319	747,373	746,353	744,975	743,612	742,283	741,622	744,274	749,039	8,960,005		8,960,005
	l.	Big Bend FGD Optimization and Utilization	213,260	212,856	212,452	212,048	211,644	211,240	210,836	210,432	210,028	209,623	209,219	208,816	2,532,454		2,532,454
	m.	Big Bend NO_x Emissions Reduction	67,316	65,794	65,707	65,633	65,571	65,509	65,520	65,605	65,931	66,559	67,188	67,632	793,965		793,965
	n.	Big Bend PM Minimization and Monitoring	92,952	92,784	92,616	92,642	92,862	93,081	93,301	93,604	94,023	94,754	95,730	96,280	1,124,629		1,124,629
	o.	Polk NO_x Emissions Reduction	17,045	17,001	16,959	16,915	16,873	16,830	16,787	16,744	16,701	16,658	16,616	16,572	201,701		201,701
	p.	Big Bend Unit 4 SOFA	27,352	27,302	27,253	27,203	27,154	27,104	27,054	27,005	26,955	26,905	26,856	26,806	324,949		324,949
	q.	Big Bend Unit 1 Pre-SCR	23,049	23,005	22,961	22,917	22,873	22,829	22,785	22,854	23,156	23,722	24,417	24,891	279,459		279,459
	r.	Big Bend Unit 2 Pre-SCR	18,485	18,445	18,406	18,365	18,326	18,286	18,246	18,207	18,167	18,127	18,088	18,048	219,196		219,196
	s.	Big Bend Unit 3 Pre-SCR	31,182	31,126	31,070	31,014	30,959	30,904	30,848	30,793	30,736	30,681	30,625	30,570	370,508		370,508
	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	913,734	1,067,966	1,080,489	1,090,101	1,100,132	1,111,009	1,121,860	1,132,832	8,618,125		8,618,125
	v.	Big Bend Unit 3 SCR	937,828	936,179	934,530	932,881	931,232	929,583	927,934	926,285	924,636	922,987	921,338	919,689	11,145,102		11,145,102
	w.	Big Bend Unit 4 SCR	692,538	691,351	690,163	688,975	687,788	686,600	685,412	684,225	683,037	681,849	680,662	679,474	8,232,074		8,232,074
	x.	Big Bend FGD System Reliability	133,496	133,277	133,058	132,839	132,620	132,401	132,182	131,963	131,744	131,524	131,305	131,085	1,587,494		1,587,494
	y.	Clean Air Mercury Rule	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	110,652		110,652
	z.	SO_2 Emissions Allowances (B)	(185)	(177)	(169)	(161)	(153)	(144)	(136)	(127)	(117)	(108)	(100)	(92)	(1,669)		(1,669)
2.		Total Investment Projects - Recoverable Costs	3,160,845	3,153,936	3,148,470	3,143,084	4,051,960	4,201,257	4,208,555	4,213,233	4,218,950	4,227,061	4,238,835	4,252,007	46,218,193	$ 159,368	$ 46,058,825
3.		Recoverable Costs Allocated to Energy	3,147,391	3,140,515	3,135,081	3,129,727	4,038,632	4,187,961	4,195,289	4,200,000	4,205,747	4,213,890	4,225,694	4,238,898	46,058,825		
4.		Recoverable Costs Allocated to Demand	13,454	13,421	13,389	13,357	13,328	13,296	13,266	13,233	13,203	13,171	13,141	13,109	159,368		
5.		Retail Energy Jurisdictional Factor	0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253			
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)	3,026,724	3,017,980	3,008,724	3,000,462	3,882,178	4,048,656	4,044,878	4,035,116	4,062,935	4,049,560	4,072,104	4,111,414	44,360,731		
8.		Jurisdictional Demand Recoverable Costs (D)	12,899	12,867	12,836	12,806	12,778	12,747	12,718	12,687	12,658	12,627	12,599	12,568	152,790		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$3,039,623	$3,030,847	$3,021,560	$3,013,268	$3,894,956	$4,061,403	$4,057,596	$4,047,803	$4,075,593	$4,062,187	$4,084,703	$4,123,982	$44,513,521		

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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TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

Form 42-4P
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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		$69,307	$98,958	$70,377	$73,685	$51,921	$54,921	$57,121	$57,421	$64,701	$127,271	$750,151	$635,411	$2,111,245
	b. Clearings to Plant		0	0	0	0	335,963	17,887	20,087	20,387	18,187	296,035	9,487	5,687	723,720
	c. Retirements		0	0	0	0	0	0	0	0	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	$83,888,924	$83,906,811	$83,926,898	$83,947,285	$83,965,472	$84,261,507	$84,270,994	$84,276,681	
3.	Less: Accumulated Depreciation	(29,343,948)	(29,545,868)	(29,747,788)	(29,949,708)	(30,151,628)	(30,353,954)	(30,556,707)	(30,759,506)	(30,962,354)	(31,165,249)	(31,368,523)	(31,572,166)	(31,775,828)	
4.	CWIP - Non-Interest Bearing	2,533,602	2,602,909	2,701,867	2,772,244	2,845,929	2,561,887	2,598,921	2,635,955	2,672,989	2,719,503	2,550,739	3,291,403	3,921,127	
5.	Net Investment (Lines 2 + 3 + 4)	$56,742,614	56,610,001	56,507,039	56,375,496	56,247,261	56,096,856	55,949,024	55,803,346	55,657,919	55,519,725	55,443,722	55,990,230	56,421,979	
6.	Average Net Investment		56,676,308	56,558,520	56,441,268	56,311,379	56,172,059	56,022,940	55,876,185	55,730,633	55,588,822	55,481,724	55,716,976	56,206,105	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		416,750	415,884	415,022	414,067	413,043	411,946	410,867	409,797	408,754	407,966	409,696	413,293	$4,947,085
	b. Debt Component (Line 6 x 2.82% x 1/12)		133,189	132,913	132,637	132,332	132,004	131,654	131,309	130,967	130,634	130,382	130,935	132,084	1,581,040
8.	Investment Expenses														
	a. Depreciation (C)		201,920	201,920	201,920	201,920	202,326	202,753	202,799	202,848	202,895	203,274	203,643	203,662	2,431,880
	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)		751,859	750,717	749,579	748,319	747,373	746,353	744,975	743,612	742,283	741,622	744,274	749,039	8,960,005
	a. Recoverable Costs Allocated to Energy		751,859	750,717	749,579	748,319	747,373	746,353	744,975	743,612	742,283	741,622	744,274	749,039	8,960,005
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		723,034	721,426	719,368	717,412	718,420	721,527	718,266	714,419	717,078	712,701	717,222	726,512	8,627,385
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)		$723,034	$721,426	$719,368	$717,412	$718,420	$721,527	$718,266	$714,419	$717,078	$712,701	$717,222	$726,512	$8,627,385

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(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 2.9%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

HEARING EXHIBIT - 00000954

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Form 42 - 7P
REVISED

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2009 to April 2009

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 1/13 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, RST	45.53%	54.11%	20,417,822	316,042	20,733,864	9,068,656	9,068,656	**0.229**
GS, GST, TS	5.48%	6.14%	2,457,493	35,862	2,493,355	1,090,649	1,090,649	**0.229**
GSD, GSDT	28.25%	24.92%	12,668,647	145,551	12,814,198	5,629,887	5,628,510	
Secondary								**0.228**
Primary								**0.225**
Transmission								**0.223**
GSLD, GSLDT, SBF	12.84%	10.05%	5,758,068	58,699	5,816,767	2,583,910	2,571,851	
Secondary								**0.226**
Primary								**0.224**
Transmission								**0.222**
IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3	6.77%	4.57%	3,035,991	26,692	3,062,683	1,393,108	1,371,631	
Secondary								**0.223**
Primary								**0.221**
Transmission								**0.219**
SL/OL	1.13%	0.21%	506,746	1,227	507,973	225,470	225,470	**0.225**
TOTAL *	100.00%	100.00%	44,844,767	584,074	45,428,841	19,991,680	19,956,767	**0.228**

Notes:
(1) From Form 42-6P, Column 8
(2) From Form 42-6P, Column 10
(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

* Totals on this schedule may not foot due to rounding

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Form 42 - 6P
REVISED

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
May 2009 to December 2009

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	54.27%	6,488,202	6,488,202	1,908	1.08536	1.054823	6,843,905	2,071	45.53%	54.83%	52.51%
GS, TS	57.68%	739,631	739,631	208	1.08536	1.054823	780,180	225	5.23%	5.96%	5.78%
GSD, SBF	80.38%	6,707,437	6,684,030	1,372	1.07602	1.046728	7,020,862	1,476	48.11%	39.10%	41.35%
LS1	515.88%	150,739	150,739	5	1.08536	1.054823	159,003	5	1.13%	0.13%	0.38%
TOTAL *		14,086,009	14,062,602	3,493			14,803,950	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 May 2009 to December 2009
(3) Based on 12 months average CP at meter
(4) Based on 2009 proposed load research data
(5) Average 12 CP load factor based on 2009 proposed load research data
(6) Projected MWh sales for the period May 2009 to December 2009
(7) Column 3 x Column 4
(8) Based on 2009 proposed load research data
(9) Column 7 / Total Column 7
(10) Column 8 x 0.25 + Column 9 x 0.75

* Totals on this schedule may not foot due to rounding

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Form 42 - 7P
REVISED

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
May 2009 to December 2009
New Allocation

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	45.530%	52.50%	14,517,293	93,169	14,610,462	6,488,202	6,488,202	**0.225**
GS, TS	5.230%	5.78%	1,667,592	10,257	1,677,849	739,631	739,631	**0.227**
GSD, SBF	48.110%	41.35%	15,339,929	73,381	15,413,310	6,707,437	6,684,030	
Secondary								**0.231**
Primary								**0.228**
Transmission								**0.226**
LS1	1.130%	0.38%	360,302	674	360,976	150,739	150,739	**0.239**
TOTAL *	100.00%	100.00%	31,885,116	177,464	32,062,580	14,086,009	14,062,602	**0.228**

* 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) Projected MWh sales for the period May 2009 to December 2009
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) Average 12 CP load factor based on 2009 proposed load research data
(7) Effective MWh sales for the period May 2009 to December 2009

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7. Refer to the August 29, 2008 filing form 42-4P, p. 21 of 26, Big Bend Unit 2 SCR, Notes (A) and (D). A depreciation rate of 2.4% is shown for account no. 312.44. Account 312.44 appears to be the account number for unit 4. Please explain. If the correct rate is not being used, provide the correct depreciation calculation.

A. Due to an inadvertent error, the correct depreciation rate was not used to calculate the depreciation expense for Big Bend Unit 2 SCR. A depreciation rate of 3.1% for account number 312.42 is the correct rate to be applied to the depreciation base when calculating depreciation expense.

Upon further review, Tampa Electric discovered an error with the depreciation rates used for Big Bend Unit 3 SCR for 2008 and 2009. The correct depreciation rates are 1.2% and 2.6% for account numbers 311.43 and 312.43, respectively.

The following affected revised forms are attached to this response:

2008 Actual/Estimated True-up
Form 42-4P, page 21 of 26

2009 Projection
Form 42-4P, page 21 of 26
Form 42-4P, page 22 of 26

The overall impacts to the 2008 Actual/Estimated True-up and 2009 Projection filings due to the corrections associated with this interrogatory are attached to the response to Interrogatory 6.

HEARING EXHIBIT - 00000958

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

Form 42-4P
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REVISED

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		$3,511,197	$3,681,092	$1,864,529	$1,638,711	$1,423,678	$1,398,014	$997,974	$928,784	$1,070,503	$1,070,503	$1,070,503	$1,094,720	$19,750,208
	b. Clearings to Plant		0	0	0	0	86,400,079	1,398,014	997,974	928,784	1,070,503	1,070,503	1,070,503	1,094,720	$94,031,080
	c. Retirements		0	0	0	0	0	0	0	0	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)	$68,350,501	$71,861,698	$75,542,790	$77,407,319	$79,046,030	$86,400,079	$87,798,093	$88,796,067	$89,724,851	$90,795,354	$91,865,857	$92,936,360	$94,031,080	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(111,600)	(336,606)	(564,707)	(795,297)	(1,028,469)	(1,264,406)	(1,503,109)	(1,744,609)	
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)	$68,350,501	71,861,698	75,542,790	77,407,319	79,046,030	86,288,479	87,461,487	88,231,360	88,929,554	89,766,885	90,601,451	91,433,251	92,286,471	
6.	Average Net Investment		70,106,100	73,702,244	76,475,055	78,226,675	82,667,255	86,874,983	87,846,424	88,580,457	89,348,220	90,184,168	91,017,351	91,859,861	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	607,866	638,806	645,949	651,347	656,992	663,139	669,266	675,461	$5,208,826
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	194,268	204,156	206,439	208,164	209,968	211,933	213,891	215,871	1,664,690
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	111,600	225,006	228,101	230,590	233,172	235,937	238,703	241,500	1,744,609
	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	913,734	1,067,968	1,080,489	1,090,101	1,100,132	1,111,009	1,121,860	1,132,832	8,618,125
	a. Recoverable Costs Allocated to Energy		0	0	0	0	913,734	1,067,968	1,080,489	1,090,101	1,100,132	1,111,009	1,121,860	1,132,832	8,618,125
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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	878,336	1,032,444	1,041,751	1,047,306	1,062,775	1,067,683	1,081,084	1,098,762	8,310,141
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	$878,336	$1,032,444	$1,041,751	$1,047,306	$1,062,775	$1,067,683	$1,081,084	$1,098,762	$8,310,141

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
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

HEARING EXHIBIT - 00000959

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 7
PAGE 2 OF 4
FILED: OCTOBER 7, 2008

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

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		$1,544,874	$2,827,383	$1,156,124	$604,491	$471,828	$443,255	$86,496	$11,216	$79,481	$433,249	$456,481	$1,077,616	$9,192,493
	b. Clearings to Plant		0	0	0	0	0	0	78,080,176	11,216	79,481	433,249	456,481	1,077,616	$80,138,219
	c. Retirements		0	0	0	0	0	0	0	0	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)	$65,783,032	$67,327,906	$70,155,289	$71,311,412	$71,915,903	$72,387,731	$72,830,986	$78,080,175	$78,091,391	$78,170,872	$78,604,121	$79,060,602	$80,138,218	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(82,743)	(248,241)	(413,837)	(579,989)	(747,105)	(915,883)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$65,783,032	67,327,906	70,155,289	71,311,412	71,915,903	72,387,731	72,830,986	77,997,432	77,843,150	77,757,035	78,024,132	78,313,497	79,222,335	
6	Average Net Investment		66,555,469	68,741,597	70,733,350	71,613,658	72,151,817	72,609,359	75,414,209	77,920,291	77,800,093	77,890,584	78,168,815	78,767,916	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	554,533	572,961	572,077	572,742	574,788	579,194	$3,426,295
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	177,223	183,113	182,830	183,043	183,697	185,105	1,095,011
8	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	82,743	165,498	165,596	166,152	167,116	168,778	915,883
	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	814,499	921,572	920,503	921,937	925,601	933,077	5,437,189
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	814,499	921,572	920,503	921,937	925,601	933,077	5,437,189
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	785,262	885,738	885,935	886,607	892,268	904,347	5,240,157
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	$785,262	$885,738	$885,935	$886,607	$892,268	$904,347	$5,240,157

Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($3,160,938), 312.43 ($76,977,280)
(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 1.2%, and 2.6%.
(D) Line 9a x Line 10
(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
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 7
PAGE 3 OF 4
FILED: OCTOBER 7, 2008

HEARING EXHIBIT - 00000960

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

Form 42-4P
Page 22 of 26
REVISED

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	
3.	Less: Accumulated Depreciation	(915,883)	(1,085,828)	(1,255,773)	(1,425,718)	(1,595,663)	(1,765,608)	(1,935,553)	(2,105,498)	(2,275,443)	(2,445,388)	(2,615,333)	(2,785,278)	(2,955,223)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$79,222,335	79,052,390	78,882,445	78,712,500	78,542,555	78,372,610	78,202,665	78,032,720	77,862,775	77,692,830	77,522,885	77,352,940	77,182,995	
6.	Average Net Investment		79,137,363	78,967,418	78,797,473	78,627,528	78,457,583	78,287,638	78,117,693	77,947,748	77,777,803	77,607,858	77,437,913	77,267,968	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		581,910	580,661	579,411	578,161	576,912	575,662	574,412	573,163	571,913	570,664	569,414	568,164	$6,900,447
	b. Debt Component (Line 6 x 2.82% x 1/12)		185,973	185,573	185,174	184,775	184,375	183,976	183,577	183,177	182,778	182,378	181,979	181,580	2,205,315
8.	Investment Expenses														
	a. Depreciation (C)		169,945	169,945	169,945	169,945	169,945	169,945	169,945	169,945	169,945	169,945	169,945	169,945	2,039,340
	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)		937,828	936,179	934,530	932,881	931,232	929,583	927,934	926,285	924,636	922,987	921,338	919,689	11,145,102
	a. Recoverable Costs Allocated to Energy		937,828	936,179	934,530	932,881	931,232	929,583	927,934	926,285	924,636	922,987	921,338	919,689	11,145,102
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		901,873	899,652	896,865	894,351	895,157	898,662	894,665	889,921	893,239	886,993	887,850	892,030	10,731,258
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		$901,873	$899,652	$896,865	$894,351	$895,157	$898,662	$894,665	$889,921	$893,239	$886,993	$887,850	$892,030	$10,731,258

Notes:

(A) Applicable depreciable base for Big Bend; account 311.43 ($3,160,938), 312.43 ($76,977,280)

(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 1.2%, and 2.6%

(D) Line 9a x Line 10

HEARING EXHIBIT - 00000961

TAMPA ELECTRIC COMPANY
DOCKET NO. 080007-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 7
PAGE 4 OF 4
FILED: OCTOBER 7, 2008

35

TECO's Revised Form 42 – 1P
10/17/08

HEARING EXHIBIT - 00000962

Form 42 - 1P
REVISED
10/17/08

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2009 to December 2009

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)	$5,259,690	$334,116	$5,593,806
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	44,360,731	152,790	44,513,521
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	49,620,421	486,906	50,107,327
2. True-up for Estimated Over/(Under) Recovery for the current period January 2008 to December 2008 (Form 42-2E, Line 5 + 6 + 10)	(7,609,055)	(144,169)	(7,753,224)
3. Final True-up for the period January 2007 to December 2007 (Form 42-1A, Line 3)	12,596,764	(132,369)	12,464,395
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2009 to December 2009 (Line 1 - Line 2- Line 3)	44,632,712	763,444	45,396,156
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$44,664,848	$763,994	$45,428,842

Notes: Allocation to energy and demand in each period is in proportion to the respective period split of costs indicated on Lines 7 and 8 of Forms 42-5 and 42-7 of the actuals and estimates.

HEARING EXHIBIT - 00000963

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TECO's 2009 Projection Schedules

HEARING EXHIBIT - 00000964

Jenny Wu

From: Wurtenberg, Dawn M. [dmwurtenberg@tecoenergy.com]
Sent: Friday, October 17, 2008 3:18 PM
To: Jenny Wu
Cc: Bryant, Howard T.
Subject: Revised ECRC Form 42-1P
Attachments: 2009 Projection Schedules_revised 101708.pdf

Jenny,
Attached is the revised schedule pursuant to our conversations regarding the calculation error found in the 2009 Projection filing.

Dawn M. Wurtenberg

Tampa Electric Company
702 N. Franklin St.
Tampa, FL 33602

Office: 813-228-1769
Fax: 813-228-1770

HEARING EXHIBIT - 00000965

Form 42 - 1P
REVISED
10/17/08

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2009 to December 2009

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)	$5,259,690	$334,116	$5,593,806
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	44,360,731	152,790	44,513,521
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	49,620,421	486,906	50,107,327
2. True-up for Estimated Over/(Under) Recovery for the current period January 2008 to December 2008 (Form 42-2E, Line 5 + 6 + 10)	(7,609,055)	(144,169)	(7,753,224)
3. Final True-up for the period January 2007 to December 2007 (Form 42-1A, Line 3)	12,596,764	(132,369)	12,464,395
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2009 to December 2009 (Line 1 - Line 2- Line 3)	44,632,712	763,444	45,396,156
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$44,664,848	$763,994	$45,428,842

Notes: Allocation to energy and demand in each period is in proportion to the respective period split of costs indicated on Lines 7 and 8 of Forms 42-5 and 42-7 of the actuals and estimates.

HEARING EXHIBIT - 00000966

APPENDIX I

ENVIRONMENTAL COST RECOVERY COMMISSION FORMS 42-1A THROUGH 42-8A

JANUARY 2007 - DECEMBER 2007 FINAL TRUE-UP

KMD-1
DOCKET NO. 080007-EI
EXHIBIT_____
PAGES 1-55

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 3
COMPANY Florida Power & Light Co. (Direct)
WITNESS Korel M. Dubin (KMD-1)
DATE 11-04-08

1

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up for the Period
January through December 2007

Line No.			
1	Over/(Under) Recovery for the Current Period (Form 42-2A Page 2 of 2, Line 5)	$1,950,088	
2	Interest Provision (Form 42-2A Page 2 of 2, Line 6)	$638,465	
3	Total		$2,588,553
4	Estimated/Actual Over/(Under) Recovery for the Same Period *	($1,186,248)	
5	Interest Provision	600,422	
6	Total		($585,826)
7	Net True-Up for the period		$3,174,379

* Per Order No. PSC-07-0922-FOF-EI issued November 16, 2007.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2007

Line No.		January	February	March	April	May	June
1	ECRC Revenues (net of Revenue Taxes)	$1,983,736	$1,707,980	$1,689,491	$1,713,020	$1,891,211	$2,088,038
2	True-up Provision (Order No. PSC-06-0972-FOF-EI)	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,321,456	3,045,700	3,027,211	3,050,739	3,228,931	3,425,758
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5A, Line 9)	566,437	598,119	1,725,067	1,037,492	621,715	1,666,686
	b - Capital Investment Projects (Form 42-7A, Line 9)	1,629,758	1,759,289	1,787,918	1,809,768	1,850,912	1,953,773
	c - Total Jurisdictional ECRC Costs	2,196,195	2,357,408	3,512,985	2,847,260	2,472,627	3,620,459
5	Over/(Under) Recovery (Line 3 - Line 4c)	1,125,261	688,292	(485,774)	203,479	756,304	(194,701)
6	Interest Provision (Form 42-3A, Line 10)	76,826	75,201	70,111	63,936	60,456	56,195
7	Prior Periods True-Up to be (Collected)/Refunded in 2007	16,052,637	15,917,004	15,342,777	13,589,394	12,519,090	11,998,130
	a - Deferred True-Up from 2006 (2006 Final True-Up Filing, Form 42-1A, Line 7)	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849
8	True-Up Collected /(Refunded) (See Line 2)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)
9	End of Period True-Up (Lines 5+6+7+7a+8)	17,480,853	16,906,626	15,153,243	14,082,939	13,561,979	12,085,753
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$17,480,853	$16,906,626	$15,153,243	$14,082,939	$13,561,979	$12,085,753

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2007

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$2,338,726	$2,357,032	$2,465,322	$2,195,500	$1,938,894	$1,859,318	$24,228,269
2	True-up Provision (Order No. PSC-06-0972-FOF-EI)	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	16,052,637
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,676,446	3,694,752	3,803,042	3,533,220	3,276,614	3,197,038	40,280,906
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5A, Line 9)	861,790	1,011,703	986,845	2,381,987	1,959,762	1,648,537	15,066,140
	b - Capital Investment Projects (Form 42-7A, Line 9)	2,041,454	2,064,421	2,069,195	2,081,168	2,096,100	2,120,922	23,264,678
	c - Total Jurisdictional ECRC Costs	2,903,244	3,076,124	3,056,040	4,463,155	4,055,862	3,769,459	38,330,818
5	Over/(Under) Recovery (Line 3 - Line 4c)	773,202	618,628	747,002	(929,935)	(779,248)	(572,421)	1,950,088
6	Interest Provision (Form 42-3A, Line 10)	51,739	50,741	47,167	37,563	27,907	20,623	638,465
7	Prior Periods True-Up to be (Collected)/Refunded in 2007	10,521,904	10,009,125	9,340,774	8,797,223	6,567,131	4,478,070	16,052,637
	a - Deferred True-Up from 2006 (2006 Final True-Up Filing, Form 42-1A, Line 7)	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849
8	True-Up Collected /(Refunded) (See Line 2)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(16,052,637)
9	End of Period True-Up (Lines 5+6+7+7a+8)	11,572,974	10,904,623	10,361,072	8,130,980	6,041,919	4,152,401	4,152,402
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$11,572,974	$10,904,623	$10,361,072	$8,130,980	$6,041,919	$4,152,401	$4,152,402

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2007

Interest Provision (in Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$17,616,486	$17,480,853	$16,906,626	$15,153,243	$14,082,939	$13,561,979
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	17,404,027	16,831,425	15,083,132	14,019,003	13,501,523	12,029,558
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$35,020,513	$34,312,278	$31,989,758	$29,172,246	$27,584,462	$25,591,537
4	Average True-Up Amount (Line 3 x 1/2)	$17,510,257	$17,156,139	$15,994,879	$14,586,123	$13,792,231	$12,795,769
5	Interest Rate (First Day of Reporting Month)	5.27000%	5.26000%	5.26000%	5.26000%	5.26000%	5.26000%
6	Interest Rate (First Day of Subsequent Month)	5.26000%	5.26000%	5.26000%	5.26000%	5.26000%	5.28000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53000%	10.52000%	10.52000%	10.52000%	10.52000%	10.54000%
8	Average Interest Rate (Line 7 x 1/2)	5.26500%	5.26000%	5.26000%	5.26000%	5.26000%	5.27000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.43875%	0.43833%	0.43833%	0.43833%	0.43833%	0.43917%
10	Interest Provision for the Month (Line 4 x Line 9)	$76,826	$75,201	$70,111	$63,936	$60,456	$56,195

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2007

Interest Provision (in Dollars)

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$12,085,753	$11,572,974	$10,904,623	$10,361,072	$8,130,980	$6,041,919	$153,899,447
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	11,521,235	10,853,882	10,313,905	8,093,417	6,014,012	4,131,778	139,796,897
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$23,606,988	$22,426,856	$21,218,528	$18,454,489	$14,144,992	$10,173,697	$293,696,344
4	Average True-Up Amount (Line 3 x 1/2)	$11,803,494	$11,213,428	$10,609,264	$9,227,245	$7,072,496	$5,086,849	$146,848,172
5	Interest Rate (First Day of Reporting Month)	5.28000%	5.24000%	5.62000%	5.05000%	4.72000%	4.75000%	N/A
6	Interest Rate (First Day of Subsequent Month)	5.24000%	5.62000%	5.05000%	4.72000%	4.75000%	4.98000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.52000%	10.86000%	10.67000%	9.77000%	9.47000%	9.73000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	5.26000%	5.43000%	5.33500%	4.88500%	4.73500%	4.86500%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.43833%	0.45250%	0.44458%	0.40708%	0.39458%	0.40542%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$51,739	$50,741	$47,167	$37,563	$27,907	$20,623	$638,465

Form 42-4A

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2007 - December 2007

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	Air Operating Permit Fees-O&M	$1,827,266	$1,822,006	$5,260	0.3%
3a	Continuous Emission Monitoring Systems-O&M	$638,023	$685,667	($47,644)	-6.9%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$2,576,606	$2,239,772	$336,834	15.0%
8a	Oil Spill Cleanup/Response Equipment-O&M	$218,529	$211,821	$6,708	3.2%
13	RCRA Corrective Action-O&M	$120,711	$103,706	$17,005	16.4%
14	NPDES Permit Fees-O&M	$124,400	$124,400	$0	0.0%
17a	Disposal of Noncontainerized Liquid Waste-O&M	$257,555	$291,368	($33,813)	-11.6%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$975,001	$1,152,314	($177,313)	-15.4%
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$114,974	$186,311	($71,337)	-38.3%
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($560,232)	($560,232)	$0	0.0%
NA	Amortization of Gains on Sales of Emissions Allowances	($1,034,225)	($1,003,674)	($30,551)	3.0%
22	Pipeline Integrity Management	$723,627	$438,646	$284,981	65.0%
23	SPCC-Spill Prevention, Control & Countermeasures	$234,582	$313,753	($79,171)	-25.2%
24	Manatee Reburn	$393,813	$458,132	($64,319)	-14.0%
25	Port Everglades ESP	$1,063,335	$1,232,950	($169,615)	-13.8%
26	UST Replacement/Removal	$6	$6	$0	0.0%
27	Lowest Quality Water Source	$253,253	$368,233	($114,980)	-31.2%
28	CWA 316(b) Phase II Rule	$1,380,164	$1,325,259	$54,905	4.1%
29	SCR Consumables	$238,273	$259,889	($21,616)	-8.3%
30	HBMP	$35,787	$42,891	($7,104)	-16.6%
31	CAIR Compliance	$727,389	$376,055	$351,334	93.4%
32	BART	$16,837	$3,397	$13,440	395.6%
34	St. Lucie Cooling Water System Inspection & Maintenance	$4,936,087	$8,088,753	($3,152,666)	-39.0%
2	Total O&M Activities	$15,261,761	$18,161,423	($2,899,662)	-16.0%
3	Recoverable Costs Allocated to Energy	$4,334,092	$4,330,396	$3,696	0.1%
4a	Recoverable Costs Allocated to CP Demand	$10,232,784	$12,958,829	($2,726,045)	-21.0%
4b	Recoverable Costs Allocated to GCP Demand	$694,885	$872,198	($177,313)	-20.3%

Notes:
Column(1) is the 12-Month Totals on Form 42-5A
Column(2) is the approved estimated/actual amount in accordance with FPSC Order No. PSC-07-0922-FOF-EI.
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2007 - December 2007

O&M Activities
(in Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of O&M Activities							
	1 Air Operating Permit Fees-O&M	$ 166,075	$ 18,529	$ 165,175	$ 153,827	$ 165,175	$ 165,175	$833,956
	3a Continuous Emission Monitoring Systems-O&M	163,176	40,359	35,896	32,003	25,644	166,212	463,290
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	9,206	(7,914)	1,311	7,249	27,965	365,710	403,527
	8a Oil Spill Cleanup/Response Equipment-O&M	17,555	13,168	13,401	37,789	13,510	5,498	100,921
	13 RCRA Corrective Action-O&M	0	12,483	6,363	0	0	0	18,846
	14 NPDES Permit Fees-O&M	124,400	0	0	0	0	0	124,400
	17a Disposal of Noncontainerized Liquid Waste-O&M	24,972	37,314	38,486	0	61,779	40,017	202,568
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	69,251	141,375	108,258	69,302	93,380	67,431	548,997
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	0	47,846	1,310	6,034	0	6	55,196
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
	20 Wastewater Discharge Elimination &Reuse	0	0	0	0	0	0	0
	NA Amortization of Gains on Sales of Emissions Allowances	(11,584)	(11,584)	(11,584)	(11,584)	(328,710)	(89,804)	(464,850)
	22 Pipeline Integrity Management	0	4,376	2,086	100,379	10,410	123,200	240,451
	23 SPCC - Spill Prevention, Control & Countermeasures	(6,847)	9,790	10,915	31,425	87,884	22,687	155,854
	24 Manatee Reburn	31,615	13,440	77,504	38,268	(318)	1,623	162,132
	25 Pt. Everglades ESP Technology	29,593	39,645	48,766	45,566	60,373	93,967	317,910
	26 UST Replacement/Removal	(5,504)	5,510	0	0	0	0	6
	27 Lowest Quality Water Source	(840)	0	39,064	0	22,911	62,816	123,951
	28 CWA 316(b) Phase II Rule	1,351	92,552	156,252	29,782	127,944	209,687	617,568
	29 SCR Consumables	6,805	4,260	26,029	8,456	27,653	44,389	117,592
	30 HBMP	1,504	2,831	5,483	2,229	2,229	1,415	15,691
	31 CAIR Compliance	(10,622)	88,727	128,928	22,650	20,417	28,455	278,555
	32 BART	0	0	0	1,797	1,600	0	3,397
	34 St. Lucie Cooling Water System Inspection & Maintenance	10,351	98,730	940,461	522,530	255,948	426,940	2,254,960
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
2	Total of O&M Activities	$ 573,771	$ 604,751	$ 1,747,418	$ 1,051,016	$ 629,108	$ 1,688,738	$ 6,294,802
3	Recoverable Costs Allocated to Energy	$ 415,789	$ 245,743	$ 520,906	$ 327,441	$ 45,327	$ 453,737	$ 2,008,943
4a	Recoverable Costs Allocated to CP Demand	$ 112,074	$ 240,976	$ 1,141,597	$ 677,616	$ 513,744	$ 1,190,913	$ 3,876,920
4b	Recoverable Costs Allocated to GCP Demand	$ 45,908	$ 118,032	$ 84,915	$ 45,959	$ 70,037	$ 44,088	$ 408,939
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	
6a	Retail CP Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 409,928	$ 242,279	$ 513,563	$ 322,825	$ 44,688	$ 447,341	$ 1,980,624
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 110,600	$ 237,808	$ 1,126,589	$ 668,708	$ 506,990	$ 1,175,257	$ 3,825,952
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 45,908	$ 118,032	$ 84,915	$ 45,959	$ 70,037	$ 44,088	$ 408,939
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 566,436	$ 598,119	$ 1,725,067	$ 1,037,492	$ 621,715	$ 1,666,686	$ 6,215,515

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2007 - December 2007

O&M Activities
(in Dollars)

Line #	Project #	Actual JUL	Actual AUG	Actual SEP	Actual OCT	Actual NOV	Actual DEC	6-Month Sub-Total	12-Month Total	Method of Classification CP Demand	GCP Demand	Energy
1	Description of O&M Activities											
	1 Air Operating Permit Fees-O&M	$ 165,175	$ 167,431	$ 165,175	$ 165,175	$ 165,175	$ 165,179	$993,310	$1,827,266			$1,827,266
	3a Continuous Emission Monitoring Systems-O&M	30,623	19,177	25,410	24,670	22,706	52,147	174,733	638,023			638,023
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	550,432	328,373	422,336	112,064	458,210	301,664	2,173,079	2,576,606	2,576,606		
	8a Oil Spill Cleanup/Response Equipment-O&M	7,164	27,973	8,628	30,593	8,004	35,246	117,608	218,529			218,529
	13 RCRA Corrective Action-O&M	0	9,943	2,564	12,919	49,550	26,889	101,865	120,711	120,711		
	14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	124,400	124,400		
	17a Disposal of Noncontainerized Liquid Waste-O&M	22,595	214	55	4,543	0	27,580	54,987	257,555			257,555
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	84,547	98,187	112,214	53,442	46,042	31,572	426,004	975,001		975,001	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	0	0	28,478	422	0	30,878	59,778	114,974	106,130		8,844
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
	20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
	NA Amortization of Gains on Sales of Emissions Allowances	(138,449)	(138,449)	(33,922)	(86,185)	(86,185)	(86,185)	(569,375)	(1,034,225)			(1,034,225)
	22 Pipeline Integrity Management	136,990	37,320	(39)	75,566	149,848	83,491	483,176	723,627	723,627		
	23 SPCC - Spill Prevention, Control & Countermeasures	34,599	25,996	4,870	(3,595)	6,231	10,627	78,728	234,582	234,582		
	24 Manatee Reburn	66,144	34,112	8,367	21,783	423	100,852	231,681	393,813			393,813
	25 Pt. Everglades ESP Technology	70,557	70,666	82,058	114,793	87,238	320,113	745,425	1,063,335			1,063,335
	26 UST Replacement/Removal	0	0	0	0	0	0	0	6	6		
	27 Lowest Quality Water Source	20,235	20,708	21,813	22,431	21,793	22,322	129,302	253,253	253,253		
	28 CWA 316(b) Phase II Rule	(8,575)	40,330	76,748	264,759	177,900	211,434	762,596	1,380,164	1,380,164		
	29 SCR Consumables	31,642	34,022	16,499	16,489	8,043	13,986	120,681	238,273			238,273
	30 HBMP	1,415	1,415	1,415	1,407	1,482	12,962	20,096	35,787	35,787		
	31 CAIR Compliance	66,309	236,739	(33,766)	122,793	64,530	(7,771)	448,834	727,389			727,389
	32 BART	0	0	13,440	0	0	0	13,440	16,837			16,837
	34 St. Lucie Cooling Water System Inspection & Maintenance	(221,953)	57,146	123,393	1,506,333	851,521	364,687	2,681,127	4,936,087	4,936,087		
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0		
2	Total of O&M Activities	$ 872,764	$1,024,617	$ 999,050	$2,413,716	$1,985,825	$1,670,987	$ 8,966,959	$15,261,761	$ 10,232,784	$ 694,885	$ 4,334,092
3	Recoverable Costs Allocated to Energy	$ 319,964	$ 450,089	$ 252,339	$ 412,891	$ 268,138	$ 621,727	$ 2,325,149	$ 4,334,092			
4a	Recoverable Costs Allocated to CP Demand	$ 491,596	$ 499,684	$ 657,840	$1,970,726	$1,694,988	$1,041,031	$ 6,355,864	$10,232,784			
4b	Recoverable Costs Allocated to GCP Demand	$ 61,204	$ 74,844	$ 88,871	$ 30,099	$ 22,699	$ 8,229	$ 285,946	$ 694,885			
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%					
6a	Retail CP Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 315,454	$ 443,744	$ 248,782	$ 407,070	$ 264,358	$ 612,962	$ 2,292,370	$ 4,272,994			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 485,133	$ 493,115	$ 649,192	$1,944,818	$1,672,705	$1,027,346	$ 6,272,309	$10,098,261			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 61,204	$ 74,844	$ 88,871	$ 30,099	$ 22,699	$ 8,229	$ 285,946	$ 694,885			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 861,791	$1,011,703	$ 986,845	$2,381,987	$1,959,762	$1,648,537	$ 8,850,625	$15,066,140			

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2007 - December 2007

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				
2	Low NOx Burner Technology-Capital	$ 908,190	$ 908,197	$ (7)	0.0%
3b	Continuous Emission Monitoring Systems-Capital	1,024,752	1,025,600	(848)	-0.1%
4b	Clean Closure Equivalency-Capital	3,990	3,990	0	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,758,710 0	1,758,715	(5)	0.0%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	1,598 0	1,600	(2)	-0.1%
8b	Oil Spill Cleanup/Response Equipment-Capital	72,834	73,475	(641)	-0.9%
10	Relocate Storm Water Runoff-Capital	9,739	9,743	(4)	0.0%
NA	SO2 Allowances-Negative Return on Investment	(281,469)	(284,008)	2,539	-0.9%
12	Scherer Discharge Pipeline-Capital	64,318	64,314	4	0.0%
17b	Disposal of Noncontainerized Liquid Wate-Capital	0	0	0	N/A
20	Wastewater Discharge Elimination & Reuse	245,828	245,826	2	0.0%
21	St. Lucie Turtle Net	92,463	92,461	2	0.0%
22	Pipeline Integrity Management	0	0	0	N/A
23	SPCC-Spill Prevention, Control & Countermeasures	2,047,287	2,036,766	10,521	0.5%
24	Manatee Reburn	4,810,532	4,886,546	(76,014)	-1.6%
25	Pt. Everglades ESP Technology	11,200,358	11,288,005	(87,647)	-0.8%
26	UST Replacement/Removal	14,136	0	14,136	N/A
31	CAIR Compliance	1,407,612	1,551,150	(143,538)	-9.3%
33	CAMR Compliance	211,174	340,077	(128,903)	-37.9%
35	Martin Plant Drinking Water System Compliance	0	0	0	N/A
2	Total Investment Projects-Recoverable Costs	$ 23,592,052	$ 24,002,457	$ (410,405)	-1.7%
3	Recoverable Costs Allocated to Energy	$ 18,118,494	$ 18,299,579	$ (181,085)	-1.0%
4	Recoverable Costs Allocated to Demand	$ 5,473,558	$ 5,702,878	$ (229,320)	-4.0%

Notes:
Column(1) is the 12-Month Totals on Form 42-7A
Column(2) is the approved estimated/actual amount in accordance with FPSC Order No. PSC-07-0922-FOF-EI.
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2007 - December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of Investment Projects (A)							
2	Low NOx Burner Technology-Capital	$78,001	$77,586	$77,172	$76,730	$76,289	$75,874	$ 461,652
3b	Continuous Emission Monitoring Systems-Capital	86,718	86,399	86,109	85,787	85,482	85,249	515,744
4b	Clean Closure Equivalency-Capital	338	337	336	335	334	333	2,013
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	148,800	148,392	147,985	147,578	147,170	146,763	886,688
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	135	135	134	134	133	133	804
8b	Oil Spill Cleanup/Response Equipment-Capital	6,035	5,997	5,961	5,926	5,940	5,947	35,806
10	Relocate Storm Water Runoff-Capital	818	817	816	815	813	812	4,891
NA	SO2 Allowances-Negative Return on Investment	(19,422)	(19,315)	(19,208)	(24,146)	(27,815)	(26,769)	(136,675)
12	Scherer Discharge Pipeline-Capital	5,418	5,407	5,397	5,386	5,375	5,365	32,348
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,672	20,638	20,604	20,570	20,537	20,502	123,523
21	St. Lucie Turtle Net	7,755	7,745	7,737	7,727	7,719	7,709	46,392
22	Pipeline Integrity Management	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	163,719	166,879	168,591	168,533	170,667	172,206	1,010,595
24	Manatee Reburn	382,829	381,975	381,117	380,166	379,142	405,709	2,310,938
25	Pt. Everglades ESP Technology	732,366	848,999	868,422	887,705	913,016	962,744	5,213,252
26	UST Removal / Replacement	0	0	0	0	0	0	0
31	CAIR Compliance	33,991	46,084	55,584	64,479	83,186	103,675	386,999
33	CAMR Compliance	4,539	6,005	6,353	7,538	8,988	15,031	48,454
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 1,652,712	$ 1,784,080	$ 1,813,110	$ 1,835,263	$ 1,876,976	$ 1,981,283	$ 10,943,424
3	Recoverable Costs Allocated to Energy	$ 1,290,663	$ 1,407,062	$ 1,425,881	$ 1,439,244	$ 1,460,796	$ 1,539,613	$ 8,563,258
4	Recoverable Costs Allocated to Demand	$ 362,049	$ 377,018	$ 387,229	$ 396,019	$ 416,180	$ 441,670	$ 2,380,166
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	
6	Retail Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,272,468	$ 1,387,227	$ 1,405,780	$ 1,418,955	$ 1,440,203	$ 1,517,909	$ 8,442,542
8	Jurisdictional Demand Recoverable Costs (C)	$ 357,290	$ 372,061	$ 382,138	$ 390,813	$ 410,709	$ 435,864	$ 2,348,875
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 1,629,758	$ 1,759,288	$ 1,787,918	$ 1,809,768	$ 1,850,912	$ 1,953,773	$ 10,791,417

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2007 - December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Actual JUL	Actual AUG	Actual SEP	Actual OCT	Actual NOV	Actual DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)										
2	Low NOx Burner Technology-Capital	$ 75,460	$ 75,044	$ 74,630	$ 74,216	$ 73,801	$ 73,387	$ 446,538	$ 908,190		$ 908,190
3b	Continuous Emission Monitoring Systems-Capital	85,125	84,794	84,527	84,697	84,885	84,980	509,008	1,024,752		1,024,752
4b	Clean Closure Equivalency-Capital	332	331	330	329	328	327	1,977	3,990	3,683	307
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	146,355	145,948	145,540	145,134	144,726	144,319	872,022	1,758,710	1,623,425	135,285
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	133	133	132	132	132	132	794	1,598	1,475	123
8b	Oil Spill Cleanup/Response Equipment-Capital	6,027	6,026	5,990	5,953	6,392	6,640	37,028	72,834	67,231	5,603
10	Relocate Storm Water Runoff-Capital	811	810	809	807	806	805	4,848	9,739	8,990	749
NA	SO2 Allowances-Negative Return on Investment	(26,407)	(25,126)	(24,329)	(23,774)	(22,978)	(22,180)	(144,794)	(281,469)		(281,469)
12	Scherer Discharge Pipeline-Capital	5,355	5,344	5,333	5,323	5,313	5,302	31,970	64,318	59,370	4,948
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,468	20,435	20,401	20,367	20,334	20,300	122,305	245,828	226,918	18,910
21	St. Lucie Turtle Net	7,701	7,692	7,683	7,674	7,665	7,656	46,071	92,463	85,350	7,113
22	Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	171,993	171,624	171,275	172,921	174,601	174,278	1,036,692	2,047,287	1,889,803	157,484
24	Manatee Reburn	432,089	430,801	418,910	407,048	405,931	404,815	2,499,594	4,810,532		4,810,532
25	Pt. Everglades ESP Technology	1,002,343	1,006,871	1,005,710	1,004,695	991,225	976,262	5,987,106	11,200,358		11,200,358
26	UST Removal / Replacement	0	0	0	2,832	5,657	5,647	14,136	14,136	13,049	1,087
31	CAIR Compliance	121,556	138,806	157,041	179,982	199,161	224,067	1,020,613	1,407,612	1,299,334	108,278
33	CAMR Compliance	20,857	23,943	24,320	22,088	27,564	43,948	162,720	211,174	194,930	16,244
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 2,070,198	$ 2,093,476	$ 2,098,302	$ 2,110,424	$ 2,125,543	$ 2,150,685	$ 12,648,628	$ 23,592,052	$ 5,473,558	$ 18,118,494
3	Recoverable Costs Allocated to Energy	$ 1,607,194	$ 1,612,468	$ 1,600,898	$ 1,590,231	$ 1,578,455	$ 1,565,989	$ 9,555,235	$ 18,118,494		
4	Recoverable Costs Allocated to Demand	$ 463,004	$ 481,008	$ 497,404	$ 520,193	$ 547,088	$ 584,696	$ 3,093,393	$ 5,473,558		
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%				
6	Retail Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%				
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,584,537	$ 1,589,737	$ 1,578,330	$ 1,567,814	$ 1,556,203	$ 1,543,913	$ 9,420,534	$ 17,863,076		
8	Jurisdictional Demand Recoverable Costs (C)	$ 456,917	$ 474,684	$ 490,865	$ 513,354	$ 539,896	$ 577,010	$ 3,052,726	$ 5,401,601		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 2,041,454	$ 2,064,421	$ 2,069,195	$ 2,081,168	$ 2,096,099	$ 2,120,923	$ 12,473,260	$ 23,264,678		

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

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements					$35,815			$35,815
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,509,209	17,509,209	17,509,209	17,509,209	17,473,393	17,473,393	17,473,393	n/a
3.	Less: Accumulated Depreciation (C)	13,903,927	13,948,794	13,993,662	14,038,529	14,047,554	14,092,367	14,137,181	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,605,282	$3,560,414	$3,515,547	$3,470,680	$3,425,840	$3,381,026	$3,336,213	n/a
6.	Average Net Investment		3,582,848	3,537,981	3,493,114	3,448,260	3,403,433	3,358,619	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		27,531	27,186	26,842	26,497	26,153	25,808	160,017
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,603	5,533	5,463	5,393	5,323	5,253	32,567
8.	Investment Expenses								
	a. Depreciation (E)		44,867	44,867	44,867	44,840	44,813	44,813	269,069
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$78,001	$77,586	$77,172	$76,730	$76,289	$75,874	$461,652

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(In Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		$35,815
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	n/a
3.	Less: Accumulated Depreciation (C)	14,137,181	14,181,994	14,226,808	14,271,621	14,316,435	14,361,248	14,406,061	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,336,213	$3,291,399	$3,246,586	$3,201,772	$3,156,959	$3,112,145	$3,067,332	n/a
6.	Average Net Investment		3,313,806	3,268,993	3,224,179	3,179,366	3,134,552	3,089,739	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		25,464	25,119	24,775	24,431	24,086	23,742	307,635
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,183	5,112	5,042	4,972	4,902	4,832	62,611
8.	Investment Expenses								
	a. Depreciation (E)		44,813	44,813	44,813	44,813	44,813	44,813	537,950
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$75,460	$75,044	$74,630	$74,216	$73,801	$73,387	$908,190

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant				-$2,635	$3,268		$18,307	$18,939
	c. Retirements					$3,478		$32,522	$36,000
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,613,846	12,613,846	12,613,846	12,611,211	12,611,001	12,611,001	12,596,785	0
3.	Less: Accumulated Depreciation (C)	6,949,745	6,984,241	7,018,736	7,053,274	7,084,327	7,118,859	7,120,868	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,664,101	$5,629,605	$5,595,110	$5,557,937	$5,526,674	$5,492,142	$5,475,917	n/a
6.	Average Net Investment		5,646,853	5,612,358	5,576,523	5,542,305	5,509,408	5,484,030	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		43,391	43,126	42,851	42,588	42,335	42,140	256,432
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,831	8,777	8,721	8,668	8,616	8,577	52,190
8.	Investment Expenses								
	a. Depreciation (E)		34,496	34,496	34,537	34,531	34,531	34,532	207,123
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$86,718	$86,399	$86,109	$85,787	$85,482	$85,249	$515,745

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$20,463	$24,307	$57,350	$62,661	$41,128	$46,984	$271,833
	c. Retirements		$23,299	$125,720	$93,887	$51,922	$35,732	$44,151	$410,712
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,596,785	12,593,949	12,492,536	12,456,000	12,466,739	12,472,135	12,474,967	n/a
3.	Less: Accumulated Depreciation (C)	7,120,868	7,132,117	7,040,726	6,980,840	6,962,848	6,961,068	6,950,869	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,475,917	$5,461,832	$5,451,811	$5,475,160	$5,503,890	$5,511,067	$5,524,098	n/a
6.	Average Net Investment		5,468,875	5,456,822	5,463,485	5,489,525	5,507,479	5,517,582	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,024	41,931	41,982	42,182	42,320	42,398	509,270
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,553	8,534	8,544	8,585	8,613	8,629	103,649
8.	Investment Expenses								
	a. Depreciation (E)		34,548	34,329	34,001	33,930	33,952	33,953	411,836
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,125	$84,794	$84,527	$84,697	$84,885	$84,980	$1,024,752

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	34,252	34,362	34,473	34,584	34,695	34,806	34,916	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$24,614	$24,504	$24,393	$24,282	$24,171	$24,060	$23,950	n/a
6.	Average Net Investment		24,559	24,448	24,337	24,227	24,116	24,005	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		189	188	187	186	185	184	1,120
	b. Debt Component (Line 6 x 1.8767% x 1/12)		38	38	38	38	38	38	228
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$338	$337	$336	$335	$334	$333	$2,013

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	34,916	35,027	35,138	35,249	35,360	35,470	35,581	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$23,950	$23,839	$23,728	$23,617	$23,506	$23,396	$23,285	n/a
6.	Average Net Investment		23,894	23,783	23,673	23,562	23,451	23,340	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		184	183	182	181	180	179	2,208
	b. Debt Component (Line 6 x 1.8767% x 1/12)		37	37	37	37	37	37	449
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	1,330
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$332	$331	$330	$329	$328	$327	$3,990

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant								$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	2,201,151	2,245,197	2,289,244	2,333,290	2,377,337	2,421,383	2,465,430	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,349,067	$11,305,020	$11,260,974	$11,216,927	$11,172,881	$11,128,834	$11,084,788	n/a
6.	Average Net Investment		11,327,044	11,282,997	11,238,951	11,194,904	11,150,858	11,106,811	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		87,039	86,700	86,362	86,024	85,685	85,347	517,157
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17,715	17,646	17,577	17,508	17,439	17,370	105,254
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	264,279
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$148,800	$148,392	$147,985	$147,578	$147,170	$146,763	$886,688

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant								$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	2,465,430	2,509,476	2,553,523	2,597,569	2,641,616	2,685,662	2,729,709	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,084,788	$11,040,742	$10,996,695	$10,952,649	$10,908,602	$10,864,556	$10,820,509	n/a
6.	Average Net Investment		11,062,765	11,018,718	10,974,672	10,930,625	10,886,579	10,842,532	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		85,008	84,670	84,331	83,993	83,654	83,316	1,022,128
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17,301	17,232	17,163	17,095	17,026	16,957	208,028
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	528,558
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$146,355	$145,948	$145,540	$145,134	$144,726	$144,319	$1,758,710

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	19,782	19,813	19,844	19,875	19,906	19,937	19,968	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,248	$11,217	$11,186	$11,155	$11,124	$11,093	$11,062	n/a
6.	Average Net Investment		11,232	11,201	11,170	11,139	11,108	11,077	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		86	86	86	86	85	85	514
	b. Debt Component (Line 6 x 1.8767% x 1/12)		18	18	17	17	17	17	105
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	186
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$135	$135	$134	$134	$133	$133	$804

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	19,968	19,999	20,030	20,061	20,092	20,123	20,154	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,062	$11,031	$11,000	$10,969	$10,938	$10,907	$10,876	n/a
6.	Average Net Investment		11,046	11,015	10,984	10,953	10,922	10,891	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		85	85	84	84	84	84	1,020
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17	17	17	17	17	17	208
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	372
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$133	$133	$132	$132	$132	$132	$1,598

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$1,997	$0	$0	$0	$531	$7,691	$10,219
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$342,502	344,499	344,499	344,499	344,499	345,030	352,721	n/a
3.	Less: Accumulated Depreciation (C)	106,058	109,915	113,760	117,605	121,451	125,343	129,241	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$236,445	$234,585	$230,739	$226,894	$223,049	$219,687	$223,480	n/a
6.	Average Net Investment		235,515	232,662	228,817	224,971	221,368	221,584	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,810	1,788	1,758	1,729	1,701	1,703	10,488
	b. Debt Component (Line 6 x 1.8767% x 1/12)		368	364	358	352	346	347	2,135
8.	Investment Expenses								
	a. Depreciation (E)		3,857	3,845	3,845	3,845	3,893	3,897	23,183
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,035	$5,997	$5,961	$5,926	$5,940	$5,947	$35,806

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$1,943				$13,152	$46,788	$72,103
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$352,721	354,665	354,665	354,665	354,665	367,817	414,605	n/a
3.	Less: Accumulated Depreciation (C)	129,241	133,211	137,208	141,205	145,203	149,618	154,045	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$223,480	$221,454	$217,456	$213,459	$209,462	$218,199	$260,560	n/a
6.	Average Net Investment		222,467	219,455	215,458	211,461	213,830	239,379	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,709	1,686	1,656	1,625	1,643	1,839	20,647
	b. Debt Component (Line 6 x 1.8767% x 1/12)		348	343	337	331	334	374	4,202
8.	Investment Expenses								
	a. Depreciation (E)		3,970	3,997	3,997	3,997	4,415	4,427	47,988
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,027	$6,026	$5,990	$5,953	$6,392	$6,640	$72,834

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	44,037	44,174	44,311	44,449	44,586	44,724	44,861	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$73,757	$73,620	$73,483	$73,345	$73,208	$73,070	$72,933	n/a
6.	Average Net Investment		73,689	73,551	73,414	73,277	73,139	73,002	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		566	565	564	563	562	561	3,382
	b. Debt Component (Line 6 x 1.8767% x 1/12)		115	115	115	115	114	114	688
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	825
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$818	$817	$816	$815	$813	$812	$4,891

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	44,861	44,998	45,136	45,273	45,411	45,548	45,686	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$72,933	$72,796	$72,658	$72,521	$72,383	$72,246	$72,108	n/a
6.	Average Net Investment		72,864	72,727	72,589	72,452	72,315	72,177	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		560	559	558	557	556	555	6,725
	b. Debt Component (Line 6 x 1.8767% x 1/12)		114	114	114	113	113	113	1,369
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	1,649
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$811	$810	$809	$807	$806	$805	$9,739

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	401,043	402,181	403,320	404,459	405,598	406,736	407,875	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$463,217	$462,079	$460,940	$459,801	$458,662	$457,524	$456,385	n/a
6.	Average Net Investment		462,648	461,509	460,370	459,232	458,093	456,954	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,555	3,546	3,538	3,529	3,520	3,511	21,199
	b. Debt Component (Line 6 x 1.8767% x 1/12)		724	722	720	718	716	715	4,315
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	6,833
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,418	$5,407	$5,397	$5,386	$5,375	$5,365	$32,348

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	407,875	409,014	410,153	411,291	412,430	413,569	414,708	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$456,385	$455,246	$454,107	$452,969	$451,830	$450,691	$449,552	n/a
6.	Average Net Investment		455,815	454,677	453,538	452,399	451,260	450,122	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,503	3,494	3,485	3,476	3,468	3,459	42,083
	b. Debt Component (Line 6 x 1.8767% x 1/12)		713	711	709	708	706	704	8,565
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	13,665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,355	$5,344	$5,333	$5,323	$5,313	$5,302	$64,318

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-in-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	519,211	522,860	526,508	530,157	533,806	537,454	541,103	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,842,451	$1,838,802	$1,835,153	$1,831,505	$1,827,856	$1,824,207	$1,820,559	n/a
6.	Average Net Investment		1,840,627	1,836,978	1,833,329	1,829,680	1,826,032	1,822,383	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		14,144	14,116	14,088	14,060	14,032	14,003	84,442
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,879	2,873	2,867	2,861	2,856	2,850	17,186
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	21,892
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,672	$20,638	$20,604	$20,570	$20,537	$20,502	$123,523

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(In Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	$541,103	544,752	548,401	552,049	555,698	559,347	562,995	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,820,559	$1,816,910	$1,813,261	$1,809,612	$1,805,964	$1,802,315	$1,798,666	n/a
6.	Average Net Investment		1,818,734	1,815,086	1,811,437	1,807,788	1,804,139	1,800,491	
7.	Return on Average Net Investment								
	Equity Component grossed up for taxes (D)		13,975	13,947	13,919	13,891	13,863	13,835	167,874
	Debt Component (Line 6 x 1.8767% x 1/12)		2,844	2,839	2,833	2,827	2,822	2,816	34,166
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	43,785
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,468	$20,435	$20,401	$20,367	$20,334	$20,300	$245,828

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	94,388	95,355	96,322	97,289	98,256	99,223	100,190	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$734,401	$733,434	$732,467	$731,500	$730,533	$729,566	$728,599	n/a
6.	Average Net Investment		733,917	732,950	731,983	731,017	730,050	729,083	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,640	5,632	5,625	5,617	5,610	5,602	33,726
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,148	1,146	1,145	1,143	1,142	1,140	6,864
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	967	967	5,802
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,755	$7,745	$7,737	$7,727	$7,719	$7,709	$46,392

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	$100,190	101,157	102,124	103,091	104,057	105,024	105,991	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$728,599	$727,632	$726,665	$725,698	$724,732	$723,765	$722,798	n/a
6.	Average Net Investment		728,116	727,149	726,182	725,215	724,248	723,281	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,595	5,588	5,580	5,573	5,565	5,558	67,184
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,139	1,137	1,136	1,134	1,133	1,131	13,674
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	967	967	11,603
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,701	$7,692	$7,683	$7,674	$7,665	$7,656	$92,463

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) Depreciation offset for base rate items.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$241,305	$360,467	$31,078	$28,672	$382,656	$30,426	$1,074,604
	c. Retirements								
	d. Other (A)						$2,738		
2.	Plant-In-Service/Depreciation Base (B)	$14,364,448	14,605,753	14,966,220	14,997,298	15,025,970	15,408,626	15,439,052	n/a
3.	Less: Accumulated Depreciation (C)	1,053,048	1,092,729	1,133,158	1,173,864	1,214,612	1,258,722	1,300,119	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$13,311,400	$13,513,024	$13,833,062	$13,823,434	$13,811,358	$14,149,904	$14,138,932	n/a
6.	Average Net Investment		13,412,212	13,673,043	13,828,248	13,817,396	13,980,631	14,144,418	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		103,062	105,066	106,259	106,175	107,430	108,688	636,679
	b. Debt Component (Line 6 x 1.8767% x 1/12)		20,976	21,384	21,626	21,609	21,865	22,121	129,580
8.	Investment Expenses								
	a. Depreciation (E)		39,681	40,429	40,706	40,749	41,372	41,397	244,334
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$163,719	$166,879	$168,591	$168,533	$170,667	$172,206	$1,010,595

Notes:

(A) Reserve Transfer/Adj.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$1,200	$1,310	$4,868	$390,804	$12,435		$1,485,222
	c. Retirements						$0		
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,439,052	15,440,252	15,441,562	15,446,430	15,837,234	15,849,669	15,849,669	n/a
3.	Less: Accumulated Depreciation (C)	$1,300,119	1,341,540	1,382,963	1,424,393	1,466,022	1,507,854	1,549,691	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,138,932	$14,098,711	$14,058,599	$14,022,038	$14,371,212	$14,341,815	$14,299,978	n/a
6.	Average Net Investment		14,118,822	14,078,655	14,040,318	14,196,625	14,356,514	14,320,897	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		108,491	108,183	107,888	109,089	110,318	110,044	1,290,693
	b. Debt Component (Line 6 x 1.8767% x 1/12)		22,081	22,018	21,958	22,202	22,452	22,397	262,688
8.	Investment Expenses								
	a. Depreciation (E)		41,421	41,423	41,429	41,630	41,831	41,837	493,905
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$171,993	$171,624	$171,275	$172,921	$174,601	$174,278	$2,047,287

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$11,713	$15,650	$11,534	$654	$0	$4,275,321	$4,314,872
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$30,223,167	30,234,879	30,250,530	30,262,064	30,262,718	30,262,718	34,538,039	n/a
3.	Less: Accumulated Depreciation (C)	789,407	900,491	1,011,620	1,122,794	1,233,989	1,345,184	1,464,242	n/a
4.	CWIP - Non Interest Bearing		0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$29,433,759	$29,334,388	$29,238,910	$29,139,270	$29,028,729	$28,917,533	$33,073,796	n/a
6.	Average Net Investment		29,384,074	29,286,649	29,189,090	29,083,999	28,973,131	30,995,665	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		225,792	225,044	224,294	223,486	222,634	238,176	1,359,426
	b. Debt Component (Line 6 x 1.8767% x 1/12)		45,954	45,802	45,649	45,485	45,312	48,475	276,677
8.	Investment Expenses								
	a. Depreciation (E)		111,083	111,129	111,174	111,195	111,196	119,058	674,835
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$382,829	$381,975	$381,117	$380,166	$379,142	$405,709	$2,310,938

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		-$17,217	$0	-$1,658,275	$0	$0	$0	$2,639,380
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$34,538,039	34,520,822	34,520,822	32,862,547	32,862,547	32,862,547	32,862,547	n/a
3.	Less: Accumulated Depreciation (C)	$1,464,242	1,591,128	1,717,980	1,841,767	1,962,489	2,083,212	2,203,935	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$33,073,796	$32,929,694	$32,802,842	$31,020,780	$30,900,058	$30,779,335	$30,658,612	n/a
6.	Average Net Investment		33,001,745	32,866,268	31,911,811	30,960,419	30,839,696	30,718,974	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		253,591	252,550	245,216	237,905	236,977	236,050	$2,821,715
	b. Debt Component (Line 6 x 1.8767% x 1/12)		51,612	51,400	49,907	48,420	48,231	48,042	$574,288
8.	Investment Expenses								
	a. Depreciation (E)		126,886	126,851	123,787	120,723	120,723	120,723	$1,414,527
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$432,089	$430,801	$418,910	$407,048	$405,931	$404,815	$4,810,532

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$4,952,476	$1,595,352	$2,248,017	$2,100,583	$1,249,385	$0	$12,145,814
	b. Clearings to Plant		$24,971,594	$572,501	$42,942	$170,427	$1,781,492	$22,004,185	$49,543,141
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$29,934,156	54,905,750	55,478,251	55,521,194	55,691,620	57,473,112	79,477,297	n/a
3.	Less: Accumulated Depreciation (C)	2,579,857	2,770,709	2,998,123	3,226,451	3,455,081	3,686,633	3,952,945	n/a
4.	CWIP - Non Interest Bearing	23,512,393	14,106,905	15,702,257	17,950,275	20,050,858	21,300,243	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$50,866,692	$66,241,946	$68,182,385	$70,245,017	$72,287,397	$75,086,722	$75,524,351	n/a
6.	Average Net Investment		58,554,319	67,212,166	69,213,701	71,266,207	73,687,059	75,305,537	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		449,941	516,470	531,850	547,621	566,224	578,660	3,190,766
	b. Debt Component (Line 6 x 1.8767% x 1/12)		91,574	105,114	108,244	111,454	115,240	117,772	649,399
8.	Investment Expenses								
	a. Depreciation (E)		190,851	227,415	228,328	228,630	231,552	266,312	1,373,088
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$732,366	$848,999	$868,422	$887,705	$913,016	$962,744	$5,213,252

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$12,145,814
	b. Clearings to Plant		$1,101,185	$70,228	$190,115	$95,059	$2,164	$15,015	$51,016,906
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)						$36,137		
2.	Plant-In-Service/Depreciation Base (B)	$79,477,297	80,578,481	80,648,709	80,838,824	80,933,883	80,936,047	80,951,062	n/a
3.	Less: Accumulated Depreciation (C)	$3,952,945	4,253,129	4,555,209	4,857,721	5,160,696	5,488,807	5,768,551	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$75,524,351	$76,325,352	$76,093,500	$75,981,104	$75,773,187	$75,447,239	$75,182,510	n/a
6.	Average Net Investment		75,924,852	76,209,426	76,037,302	75,877,145	75,610,213	75,314,875	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		583,419	585,606	584,283	583,053	581,002	578,732	$6,686,861
	b. Debt Component (Line 6 x 1.8767% x 1/12)		118,740	119,185	118,916	118,666	118,248	117,786	$1,360,940
8.	Investment Expenses								
	a. Depreciation (E)		300,184	302,080	302,511	302,976	291,975	279,744	$3,152,558
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,002,343	$1,006,871	$1,005,710	$1,004,695	$991,225	$976,262	$11,200,358

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$492,916	$0	$0	$492,916
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	555	1,664	2,773	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$492,362	$491,253	$490,144	n/a
6.	Average Net Investment		0	0	0	246,181	491,807	490,698	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	1,892	3,779	3,771	$9,441
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	385	769	767	$1,922
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	555	1,109	1,109	$2,773
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$2,832	$5,657	$5,647	$14,136

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,140,561	$1,474,564	$579,965	$1,343,744	$2,701,874	$1,729,136	$8,969,845
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	3,105,197	4,245,758	5,720,322	6,300,288	7,644,032	10,345,905	12,075,042	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,105,197	$4,245,758	$5,720,322	$6,300,288	$7,644,032	$10,345,905	$12,075,042	n/a
6.	Average Net Investment		3,675,477	4,983,040	6,010,305	6,972,160	8,994,968	11,210,473	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		28,243	38,291	46,184	53,575	69,119	86,143	321,555
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,748	7,793	9,400	10,904	14,067	17,532	65,444
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$33,991	$46,084	$55,584	$64,479	$83,186	$103,675	$386,999

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$2,137,685	$1,592,798	$2,350,738	$2,610,536	$1,537,231	$3,774,844	$22,973,676
	b. Clearings to Plant		$0	$0	$0	$0	$0	$57,722	$57,722
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	57,722	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	75	n/a
4.	CWIP - Non Interest Bearing	$12,075,042	14,212,726	15,805,524	18,156,263	20,766,798	22,304,030	26,078,873	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$12,075,042	$14,212,726	$15,805,524	$18,156,263	$20,766,798	$22,304,030	$26,136,521	n/a
6.	Average Net Investment		13,143,884	15,009,125	16,980,894	19,461,531	21,535,414	24,220,275	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		101,000	115,333	130,484	149,546	165,482	186,113	$1,169,511
	b. Debt Component (Line 6 x 1.8767% x 1/12)		20,556	23,473	26,557	30,436	33,680	37,878	$238,024
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	75	$75
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$121,556	$138,806	$157,041	$179,982	$199,161	$224,067	$1,407,612

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$258,550	$58,605	$16,677	$239,395	$74,270	$1,232,705	$1,880,201
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	361,479	620,029	678,634	695,311	934,706	1,008,976	2,241,681	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$361,479	$620,029	$678,634	$695,311	$934,706	$1,008,976	$2,241,681	n/a
6.	Average Net Investment		490,754	649,331	686,972	815,008	971,841	1,625,328	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,771	4,990	5,279	6,263	7,468	12,489	40,259
	b. Debt Component (Line 6 x 1.8767% x 1/12)		767	1,016	1,074	1,275	1,520	2,542	8,194
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,539	$6,005	$6,353	$7,538	$8,988	$15,031	$48,454

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(In Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$27,182	$640,315	($558,849)	$76,120	$1,108,066	$2,435,203	$5,608,238
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$2,241,681	2,268,863	2,909,178	2,350,329	2,426,449	3,534,515	5,969,718	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,241,681	$2,268,863	$2,909,178	$2,350,329	$2,426,449	$3,534,515	$5,969,718	n/a
6.	Average Net Investment		2,255,272	2,589,021	2,629,753	2,388,389	2,980,482	4,752,116	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		17,330	19,894	20,207	18,353	22,903	36,516	$175,462
	b. Debt Component (Line 6 x 1.8767% x 1/12)		3,527	4,049	4,113	3,735	4,661	7,432	$35,711
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,857	$23,943	$24,320	$22,088	$27,564	$43,948	$211,174

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Drinking Water System Compliance (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Drinking Water System Compliance (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Reserve Transfer
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	End of Period Amount	
1	Working Capital Dr (Cr)									
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b 158.200 Allowances Withheld	0	0	0	0	0	0	0		
	c 182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
	d 254.900 Other Regulatory Liabilities-Gains	(2,105,917)	(2,094,333)	(2,082,750)	(2,071,166)	(3,150,774)	(2,864,494)	(2,924,623)		
2	Total Working Capital	($2,105,917)	($2,094,333)	($2,082,750)	($2,071,166)	($3,150,774)	($2,864,494)	($2,924,623)		
3	Average Net Working Capital Balance		(2,100,125)	(2,088,542)	(2,076,958)	(2,610,970)	(3,007,634)	(2,894,558)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(16,138)	(16,049)	(15,960)	(20,063)	(23,111)	(22,242)	(113,563)	
	b Debt Component (Line 6 x 1.87670% x 1/12)		(3,284)	(3,266)	(3,248)	(4,083)	(4,704)	(4,527)	(23,113)	
5	Total Return Component		($19,422)	($19,315)	($19,208)	($24,146)	($27,815)	($26,769)	($136,675)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(11,584)	(11,584)	(11,584)	(11,584)	(328,710)	(89,804)	(464,848)	
	b 411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	-	
	c 509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($11,584)	($11,584)	($11,584)	($11,584)	($328,710)	($89,804)	(464,850)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(31,006)	(30,899)	(30,791)	(35,730)	(356,525)	(116,573)		
	a Recoverable Costs Allocated to Energy		(31,006)	(30,899)	(30,791)	(35,730)	(356,525)	(116,573)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(30,551)	(30,445)	(30,340)	(35,206)	(351,296)	(114,863)	(592,702)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($30,551)	($30,445)	($30,340)	($35,206)	($351,296)	($114,863)	($592,702)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(In Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	End of Period Amount	
1	Working Capital Dr (Cr)									
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b 158.200 Allowances Withheld	0	0	0	0	0	0	0		
	c 182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
	d 254.900 Other Regulatory Liabilities-Gains	(2,924,623)	(2,786,174)	(2,647,725)	(2,613,803)	(2,527,618)	(2,441,433)	(2,355,248)		
2	Total Working Capital	($2,924,623)	($2,786,174)	($2,647,725)	($2,613,803)	($2,527,618)	($2,441,433)	($2,355,248)		
3	Average Net Working Capital Balance		(2,855,399)	(2,716,950)	(2,630,764)	(2,570,711)	(2,484,526)	(2,398,340)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(21,941)	(20,877)	(20,215)	(19,754)	(19,092)	(18,429)	(233,871)	
	b Debt Component (Line 6 x 1.6698% x 1/12)		(4,466)	(4,249)	(4,114)	(4,020)	(3,886)	(3,751)	(47,599)	
5	Total Return Component		($26,407)	($25,126)	($24,329)	($23,774)	($22,978)	($22,180)	(281,469)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(138,449)	(138,449)	(33,922)	(86,185)	(86,185)	(86,185)	(1,034,225)	
	b 411.900 Losses from Dispositions of Allowances			0	0	0	0	0	-	
	c 509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($138,449)	($138,449)	($33,922)	($86,185)	($86,185)	($86,185)	(1,034,225)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($164,856)	($163,575)	($58,250)	($109,959)	($109,163)	($108,365)		
	a Recoverable Costs Allocated to Energy		(164,856)	(163,575)	(58,250)	(109,959)	(109,163)	(108,365)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Reserve Retail Energy-Related Recoverable Costs (B)		(162,438)	(161,176)	(57,396)	(108,347)	(107,562)	(106,776)	(1,296,397)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($162,438)	($161,176)	($57,396)	($108,347)	($107,562)	($106,776)	($1,296,397)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
2007 Annual Capital Recovery Schedule (Actual)

Project Number	Function	Plant Name	Utility Account	Depreciation Rate / Amortization Period	Actual December 31, 2006 Plant In Service	Actual December 31, 2007 Plant In Service
02-LOW NOX BURNER TECHNOLOGY						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	2,700,574.97	2,700,574.97
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	2,451,904.92	2,416,089.59
		TOTAL 02-LOW NOX BURNER TECHNOLOGY			17,509,208.50	17,473,393.17
03-CONTINUOUS EMISSION MONITORING						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	59,227.10	59,227.10
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.30%	30,059.25	26,354.96
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.40%	494,606.87	494,606.87
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.10%	511,705.24	511,705.24
	02 - Steam Generation Plant	Cutler Comm	31100	0.00%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	0.50%	27,351.73	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	0.20%	312,722.43	310,454.41
	02 - Steam Generation Plant	Cutler U6	31200	1.00%	314,129.96	311,861.95
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	472,570.03	477,896.88
	02 - Steam Generation Plant	Manatee U2	31100	4.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	508,734.36	508,734.36
	02 - Steam Generation Plant	Martin Comm	31200	4.10%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.50%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.80%	521,075.17	524,263.86
	02 - Steam Generation Plant	Martin U2	31100	1.50%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.50%	519,484.96	520,421.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.20%	61,620.47	51,132.85
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	453,661.22	461,988.64
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	475,113.36	475,113.36
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	503,968.62	512,296.04
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	512,809.90	517,303.41
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.40%	29,117.75	11,495.25
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	449,392.38	449,392.38
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	433,421.96	433,421.96
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	431,831.34	434,357.43
	02 - Steam Generation Plant	Scherer U4	31200	1.90%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	66,188.18	66,188.18
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	107,594.02	107,594.02
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	107,562.94	107,562.94
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.30%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm	31200	2.10%	29,110.85	37,954.50
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	546,534.15	543,842.20
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	505,638.44	502,946.49
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.10%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	5.00%	461,080.14	463,054.20
	05 - Other Generation Plant	FtLauderdale U5	34300	3.70%	471,313.47	474,559.99
	05 - Other Generation Plant	FtMyers U2	34300	5.50%	106,324.08	4,970.69
	05 - Other Generation Plant	FtMyers U3	34300	5.60%	2,635.22	0.00
	05 - Other Generation Plant	Martin U3	34300	5.80%	431,927.00	411,933.88
	05 - Other Generation Plant	Martin U4	34300	5.70%	421,026.31	404,560.55
	05 - Other Generation Plant	Martin U8	34300	5.50%	25,657.00	13,876.71
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	6.30%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.20%	335,440.55	332,065.69
	05 - Other Generation Plant	Putnam U2	34300	5.40%	368,844.07	365,469.22
	05 - Other Generation Plant	Sanford U4	34300	5.60%	45,032.12	98,339.95
	05 - Other Generation Plant	Sanford U5	34300	5.70%	104,111.16	56,521.05
		TOTAL 03-CONTINUOUS EMISSION MONITORING			12,613,845.87	12,474,967.00
04-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	17,254.20	17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.30%	21,799.28	21,799.28
		TOTAL 04-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION			58,865.78	58,865.78
05-MAINTENANCE OF ABOVE GROUND FUEL TANKS						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin U1	31100	1.50%	176,338.83	176,338.83

Florida Power & Light Company
Environmental Cost Recovery Clause
2007 Annual Capital Recovery Schedule (Actual)

Project Number	Function	Plant Name	Utility Account	Depreciation Rate / Amortization Period	Actual December 31, 2006 Plant In Service	Actual December 31, 2007 Plant In Service
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.30%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	68,893.65	68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	749,025.94	749,025.94
		TOTAL 05-MAINTENANCE OF ABOVE GROUND FUEL TANKS			13,550,217.48	13,550,217.48
07-RELOCATE TURBINE LUBE OIL PIPING						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	31,030.00	31,030.00
		TOTAL 07-RELOCATE TURBINE LUBE OIL PIPING			31,030.00	31,030.00
08-OIL SPILL CLEANUP/RESPONSE EQUIPMENT						
	02 - Steam Generation Plant	CapeCanaveral Comm	31670	7-Year	26,239.13	26,239.13
	02 - Steam Generation Plant	Manatee Comm	31670	7-Year	11,861.15	46,057.66
	02 - Steam Generation Plant	Martin Comm	31600	3.20%	23,107.32	23,107.32
	02 - Steam Generation Plant	Martin Comm	31670	7-Year	109,127.14	144,558.88
	02 - Steam Generation Plant	PtEverglades Comm	31670	7-Year	47,767.08	48,297.96
	02 - Steam Generation Plant	Riviera Comm	31670	7-Year	12,491.00	12,491.00
	02 - Steam Generation Plant	Sanford U3	31670	7-Year	29,953.82	29,953.82
	02 - Steam Generation Plant	Turkey Pt Comm	31670	7-Year	35,096.72	35,096.72
	02 - Steam Generation Plant	Turkey Pt U1	31670	7-Year	1,159.18	1,159.18
	05 - Other Generation Plant	FtLauderdale Comm	34670	7-Year	3,280.00	3,280.00
	05 - Other Generation Plant	FtMyers Comm	34670	7-Year	31,677.58	31,677.58
	05 - Other Generation Plant	Putnam Comm	34670	7-Year	10,741.96	10,741.96
	08 - General Plant	General Plant	39190	3-Year	0.00	1,943.47
		TOTAL 08-OIL SPILL CLEANUP/RESPONSE EQUIPMENT			342,502.08	414,604.68
10-REROUTE STORMWATER RUNOFF						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	117,793.83	117,793.83
		TOTAL 10-REROUTE STORMWATER RUNOFF			117,793.83	117,793.83
12-SCHERER DISCHARGE PIPELINE						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.60%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.00%	689.11	689.11
		TOTAL 12-SCHERER DISCHARGE PIPELINE			864,260.42	864,260.42
20-WASTEWATER/STORMWATER DISCH ELIMINATION						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.80%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.50%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	560,786.81	560,786.81
		TOTAL 20-WASTEWATER/STORMWATER DISCH ELIMINATION			2,361,661.78	2,361,661.78
21-ST.LUCIE TURTLE NETS						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	828,789.34	828,789.34
		TOTAL 21-ST.LUCIE TURTLE NETS			828,789.34	828,789.34
23-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	665,907.33	665,907.33
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	13,451.85	13,451.85
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.90%	13,450.30	13,450.30
	02 - Steam Generation Plant	Cutler Comm	31400	0.00%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	95,458.00	336,763.43
	02 - Steam Generation Plant	Manatee Comm	31500	3.70%	5,000.00	5,000.00
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	10,379.00	10,379.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	736,958.97	736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	894,298.77	894,298.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	213,687.21	213,687.21
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm	31500	2.10%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	0.00	404,549.02
	03 - Nuclear Generation Plant	StLucie U1	32400	1.70%	0.00	437,714.57
	03 - Nuclear Generation Plant	StLucie U2	32300	1.90%	0.00	396,779.37
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.80%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	513,250.07	513,250.07

Florida Power & Light Company
Environmental Cost Recovery Clause
2007 Annual Capital Recovery Schedule (Actual)

Project Number	Function	Plant Name	Utility Account	Depreciation Rate / Amortization Period	Actual December 31, 2006 Plant In Service	Actual December 31, 2007 Plant In Service
	05 - Other Generation Plant	FtMyers GTs	34100	2.10%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.90%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2	34300	5.50%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3	34500	4.80%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.40%	61,215.95	61,215.95
	05 - Other Generation Plant	PtEverglades GTs	34100	1.50%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.20%	60,746.93	60,746.93
	05 - Other Generation Plant	Sanford Comm	34670	7-Year	7,065.10	7,065.10
	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	2.50%	951,562.91	951,562.91
	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.80%	177,981.88	177,981.88
	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	2.60%	2,862,088.65	2,862,093.44
	08 - General Plant	General Plant	39000	2.70%	7,975.00	12,843.35
		TOTAL 23-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES			**14,364,447.18**	**15,849,668.71**
24-GAS REBURN						
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	15,479,973.76	16,771,308.37
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	14,743,192.81	16,091,238.26
			TOTAL 24-GAS REBURN		**30,223,166.57**	**32,862,546.63**
25-PPE ESP TECHNOLOGY						
	02 - Steam Generation Plant	PtEverglades U1	31100	2.60%	0.00	298,709.93
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	13,082,737.27	10,404,603.15
	02 - Steam Generation Plant	PtEverglades U1	31500	2.00%	418,393.78	2,500,248.85
	02 - Steam Generation Plant	PtEverglades U1	31600	1.00%	0.00	307,032.30
	02 - Steam Generation Plant	PtEverglades U2	31100	2.60%	0.00	184,084.01
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	15,794,922.02	11,979,735.29
	02 - Steam Generation Plant	PtEverglades U2	31500	2.10%	638,102.67	3,954,581.63
	02 - Steam Generation Plant	PtEverglades U2	31600	1.70%	0.00	324,086.94
	02 - Steam Generation Plant	PtEverglades U3	31100	2.60%	0.00	4,812,793.71
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	0.00	16,040,755.59
	02 - Steam Generation Plant	PtEverglades U3	31500	2.20%	0.00	2,404,282.44
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	0.00	24,864,782.55
	02 - Steam Generation Plant	PtEverglades U4	31500	2.10%	0.00	2,875,365.39
			TOTAL 25-PPE ESP TECHNOLOGY		**29,934,155.74**	**80,951,061.78**
26-UST REPLACEMENT/REMOVAL						
	08 - General Plant	General Plant	39000	2.70%	0.00	492,916.42
			TOTAL 26-UST REPLACEMENT/REMOVAL		**0.00**	**492,916.42**
31-CLEAN AIR INTERSTATE RULE						
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	0.00	57,722.33
			TOTAL 31-CLEAN AIR INTERSTATE RULE		**0.00**	**57,722.33**
				GRAND TOTAL	**122,799,944.57**	**178,389,499.35**

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-8E

JANUARY 2008 – DECEMBER 2008
ESTIMATED/ACTUAL TRUE-UP

KMD-2
DOCKET NO. 080007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _____

1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 4
COMPANY Florida Power + Light Co. (Direct)
WITNESS Korel M. Dubin (KMD-2)
DATE 11-04-08

Form 42-1E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up
for the Period January through December 2008

Line No.		
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Page 2 of 2, Line 5)	($5,816,598)
2	Interest Provision (Form 42-2E, Page 2 of 2, Line 6)	$88,022
3	Sum of Current Period Adjustments (Form 42-2E, Page 2 of 2, Line 10)	$0
4	Estimated/Actual True-up to be refunded/(recovered) in January through December 2008	($5,728,576)

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2008

Line No.		January	February	March	April	May	June
1	ECRC Revenues (net of Revenue Taxes)	$3,100,841	$2,884,144	$2,853,259	$2,956,273	$3,236,589	$3,795,339
2	True-up Provision (Order No. PSC-07-0922-FOF-EI)	81,502	81,502	81,502	81,502	81,502	81,502
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,182,343	2,965,646	2,934,761	3,037,775	3,318,091	3,876,841
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5E, Line 9)	902,508	428,125	949,072	631,259	771,263	1,437,806
	b - Capital Investment Projects (Form 42-7E, Line 9)	2,157,693	2,202,282	2,254,944	2,312,534	2,396,491	2,496,951
	c - Total Jurisdictional ECRC Costs	3,060,201	2,630,407	3,204,016	2,943,793	3,167,754	3,934,757
5	Over/(Under) Recovery (Line 3 - Line 4c)	122,142	335,239	(269,255)	93,982	150,337	(57,916)
6	Interest Provision (Form 42-3E, Line 10)	14,013	11,142	10,240	9,430	9,196	8,462
7	Prior Periods True-Up to be (Collected)/Refunded in 2008	978,023	1,032,676	1,297,555	957,038	978,948	1,056,979
	a - Deferred True-Up from 2007 (Form 42-1A, Line 7)	3,174,379	3,174,379	3,174,379	3,174,379	3,174,379	3,174,379
8	True-Up Collected /(Refunded) (See Line 2)	(81,502)	(81,502)	(81,502)	(81,502)	(81,502)	(81,502)
9	End of Period True-Up (Lines 5+6+7+7a+8)	4,207,055	4,471,934	4,131,417	4,153,327	4,231,358	4,100,402
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$4,207,055	$4,471,934	$4,131,417	$4,153,327	$4,231,358	$4,100,402

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2008

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$3,950,317	$4,058,358	$3,946,642	$3,758,360	$3,358,808	$3,237,870	$41,136,800
2	True-up Provision (Order No. PSC-07-0922-FOF-EI)	81,502	81,502	81,502	81,502	81,502	81,502	978,023
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	4,031,819	4,139,860	4,028,144	3,839,862	3,440,310	3,319,372	42,114,823
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5E, Line 9)	1,692,021	1,193,337	2,045,349	1,939,500	2,183,293	2,004,929	16,178,462
	b - Capital Investment Projects (Form 42-7E, Line 9)	2,622,350	2,780,610	2,914,325	3,011,128	3,124,202	3,479,449	31,752,959
	c - Total Jurisdictional ECRC Costs	4,314,371	3,973,947	4,959,674	4,950,628	5,307,495	5,484,378	47,931,421
5	Over/(Under) Recovery (Line 3 - Line 4c)	(282,552)	165,913	(931,530)	(1,110,766)	(1,867,185)	(2,165,006)	(5,816,598)
6	Interest Provision (Form 42-3E, Line 10)	8,000	7,731	6,799	4,561	1,364	(2,916)	88,022
7	Prior Periods True-Up to be (Collected)/Refunded in 2008	926,023	569,969	662,111	(344,122)	(1,531,829)	(3,479,152)	978,023
	a - Deferred True-Up from 2007 (Form 42-1A, Line 7)	3,174,379	3,174,379	3,174,379	3,174,379	3,174,379	3,174,379	
8	True-Up Collected /(Refunded) (See Line 2)	(81,502)	(81,502)	(81,502)	(81,502)	(81,502)	(81,502)	(978,023)
9	End of Period True-Up (Lines 5+6+7+7a+8)	3,744,348	3,836,490	2,830,257	1,642,550	(304,773)	(2,554,197)	(5,728,576)
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$3,744,348	3,836,490	2,830,257	1,642,550	(304,773)	(2,554,197)	(5,728,576)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2008

Interest Provision (In Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$4,152,402	$4,207,055	$4,471,934	$4,131,417	$4,153,327	$4,231,358
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	4,193,042	4,460,792	4,121,177	4,143,897	4,222,162	4,091,940
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$8,345,444	$8,667,847	$8,593,111	$8,275,314	$8,375,489	$8,323,298
4	Average True-Up Amount (Line 3 x 1/2)	$4,172,722	$4,333,923	$4,296,555	$4,137,657	$4,187,744	$4,161,649
5	Interest Rate (First Day of Reporting Month)	4.98000%	3.08000%	3.09000%	2.63000%	2.84000%	2.43000%
6	Interest Rate (First Day of Subsequent Month)	3.08000%	3.09000%	2.63000%	2.84000%	2.43000%	2.45000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.06000%	6.17000%	5.72000%	5.47000%	5.27000%	4.88000%
8	Average Interest Rate (Line 7 x 1/2)	4.03000%	3.08500%	2.86000%	2.73500%	2.63500%	2.44000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.33583%	0.25708%	0.23833%	0.22792%	0.21958%	0.20333%
10	Interest Provision for the Month (Line 4 x Line 9)	$14,013	$11,142	$10,240	$9,430	$9,196	$8,462

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2008

Interest Provision (In Dollars)

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$4,100,402	$3,744,348	$3,836,490	$2,830,257	$1,642,550	($304,773)	N/A
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	3,736,348	3,828,759	2,823,458	1,637,989	(306,137)	(2,551,281)	N/A
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$7,836,750	$7,573,107	$6,659,948	$4,468,246	$1,336,413	($2,856,054)	N/A
4	Average True-Up Amount (Line 3 x 1/2)	$3,918,375	$3,786,553	$3,329,974	$2,234,123	$668,207	($1,428,027)	N/A
5	Interest Rate (First Day of Reporting Month)	2.45000%	2.45000%	2.45000%	2.45000%	2.45000%	2.45000%	N/A
6	Interest Rate (First Day of Subsequent Month)	2.45000%	2.45000%	2.45000%	2.45000%	2.45000%	2.45000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	4.90000%	4.90000%	4.90000%	4.90000%	4.90000%	4.90000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	2.45000%	2.45000%	2.45000%	2.45000%	2.45000%	2.45000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.20417%	0.20417%	0.20417%	0.20417%	0.20417%	0.20417%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$8,000	$7,731	$6,799	$4,561	$1,364	($2,916)	$88,022

Form 42

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
January 2008 - December 2008

Variance Report of O&M Activities
(In Dollars)

Line		(1) Estimated Actual	(2) Original Projections	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
1	Air Operating Permit Fees-O&M	$1,640,982	$1,965,264	($324,282)	-16.5%
3a	Continuous Emission Monitoring Systems-O&M	$957,685	$751,782	$205,903	27.4%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$1,513,172	$677,072	$836,100	123.5%
8a	Oil Spill Cleanup/Response Equipment-O&M	$276,344	$276,800	($456)	-0.2%
13	RCRA Corrective Action-O&M	$64,978	$122,000	($57,022)	-46.7%
14	NPDES Permit Fees-O&M	$124,395	$154,900	($30,505)	-19.7%
17a	Disposal of Noncontainerized Liquid Waste-O&M	$331,803	$299,000	$32,803	11.0%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$1,633,506	$967,700	$665,806	68.8%
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$342,390	$356,500	($14,110)	-4.0%
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($560,232)	($560,232)	$0	0.0%
20	Wastewater Discharge Elimination & Reuse	$0	$0	$0	N/A
NA	Amortization of Gains on Sales of Emissions Allowances	($983,208)	($1,077,648)	$94,440	-8.8%
21	St. Lucie Turtle Net	$0	$10,000	($10,000)	-100.0%
22	Pipeline Integrity Management	$414,465	$260,000	$154,465	59.4%
23	SPCC-Spill Prevention, Control & Countermeasures	$754,325	$387,000	$367,325	94.9%
24	Manatee Reburn	$499,997	$500,000	($3)	0.0%
25	Port Everglades ESP	$1,991,699	$2,352,384	($360,685)	-15.3%
26	UST Replacement/Removal	$0	$0	$0	N/A
27	Lowest Quality Water Source	$246,103	$300,900	($54,797)	-18.2%
28	CWA 316(b) Phase II Rule	$385,137	$1,433,728	($1,048,591)	-73.1%
29	SCR Consumables	$361,930	$855,200	($493,270)	-57.7%
30	HBMP	$19,999	$40,400	($20,401)	-50.5%
31	CAIR Compliance	$1,242,112	$1,795,004	($552,892)	-30.8%
32	BART	$1,355	$0	$1,355	N/A
33	St. Lucie Cooling Water System Inspection & Maintenance	$4,996,865	$442,000	$4,554,865	1030.5%
35	Martin Plant Drinking Water System Compliance	$0	$17,000	($17,000)	-100.0%
36	Low Level Radioactive Waste	$120,271	$0	$120,271	N/A
2	Total O&M Activities	$16,376,072	$12,326,754	$4,049,318	32.8%
3	Recoverable Costs Allocated to Energy	$6,360,367	$7,723,662	($1,363,295)	-17.7%
4a	Recoverable Costs Allocated to CP Demand	$8,662,315	$3,915,508	$4,746,807	121.2%
4b	Recoverable Costs Allocated to GCP Demand	$1,353,390	$687,584	$665,806	96.8%

Notes:
Column(1) is the 12-Month Totals on Form 42-5E
Column(2) is the approved projected amount in accordance with
FPSC Order No. PSC-07-0922-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2008 - December 2008

O&M Activities
(in Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of O&M Activities							
1	Air Operating Permit Fees-O&M	196,527	(134,589)	196,527	153,613	153,613	153,613	719,304
3a	Continuous Emission Monitoring Systems-O&M	233,577	15,515	35,043	39,344	29,578	43,475	396,532
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	(6,866)	15,106	353,242	321,824	428,297	256,002	1,367,604
8a	Oil Spill Cleanup/Response Equipment-O&M	2,599	5,086	39,949	18,131	10,544	51,916	128,226
13	RCRA Corrective Action-O&M	0	2,000	0	4,645	0	0	6,645
14	NPDES Permit Fees-O&M	124,400	13,583	0	0	(13,588)	0	124,395
17a	Disposal of Noncontainerized Liquid Waste-O&M	0	8,782	36,957	28,698	35,532	70,062	180,030
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	17,067	4,595	4,238	86,447	24,371	11,508	148,226
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	33,400	1,139	22,981	228	16	8,225	65,990
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
20	Wastewater Discharge Elimination &Reuse	0	0	0	0	0	0	0
NA	Amortization of Gains on Sales of Emissions Allowances	(18,608)	(18,608)	(18,608)	(18,608)	(281,499)	(89,611)	(445,542)
21	St. Lucie Turtle Net	0	0	0	0	0	0	0
22	Pipeline Integrity Management	1,267	44,518	27,366	16,283	24,955	(4,924)	109,465
23	SPCC - Spill Prevention, Control & Countermeasures	3,073	6,039	7,649	15,094	11,967	38,967	82,791
24	Manatee Reburn	1,336	19,999	31,432	85,777	62,320	94,222	295,086
25	Pt. Everglades ESP Technology	98,999	116,552	72,030	60,451	112,346	117,013	577,390
26	UST Replacement/Removal	0	0	0	0	0	0	0
27	Lowest Quality Water Source	21,167	21,725	20,835	21,637	21,182	22,601	129,147
28	CWA 316(b) Phase II Rule	32,338	49,927	30,405	(162,519)	44,946	103,277	98,374
29	SCR Consumables	38,128	22,404	33,637	36,950	32,225	24,533	187,877
30	HBMP	0	1,482	2,245	1,482	1,482	1,482	8,172
31	CAIR Compliance	180,550	256,769	104,509	22,045	41,257	61,092	666,221
32	BART	0	0	832	0	522	0	1,355
34	St. Lucie Cooling Water System Inspection & Maintenance	2,977	26,922	7,605	(45,674)	85,740	522,093	601,662
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
36	Low Level Radioactive Waste	0	0	0	0	2,165	18,107	20,271
		915,246	434,260	962,189	639,161	781,284	1,456,964	5,189,104
3	Recoverable Costs Allocated to Energy	$ 733,882	$ 290,202	$ 532,281	$ 424,622	$ 195,271	$ 530,402	$ 2,706,659
4a	Recoverable Costs Allocated to CP Demand	$ 187,640	$ 162,807	$ 449,013	$ 151,435	$ 584,986	$ 938,397	$ 2,474,277
4b	Recoverable Costs Allocated to GCP Demand	$ (6,276)	$ (18,748)	$ (19,105)	$ 63,104	$ 1,028	$ (11,835)	$ 8,168
5	Retail Energy Jurisdictional Factor	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	
6a	Retail CP Demand Jurisdictional Factor	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 723,470	$ 286,084	$ 524,729	$ 418,597	$ 192,500	$ 522,876	$ 2,668,256
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 185,314	$ 160,789	$ 443,448	$ 149,558	$ 577,735	$ 926,765	$ 2,443,609
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ (6,276)	$ (18,748)	$ (19,105)	$ 63,104	$ 1,028	$ (11,835)	$ 8,168
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 902,508	$ 428,125	$ 949,072	$ 631,259	$ 771,263	$ 1,437,806	$ 5,120,033

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2008 - December 2008

O&M Activities
(in Dollars)

Line #	Project #	Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification CP Demand	GCP Demand	Energy
1	Description of O&M Activities											
	1 Air Operating Permit Fees-O&M	153,613	153,613	153,613	153,613	153,613	153,613	921,678	1,640,982			$1,640,982
	3a Continuous Emission Monitoring Systems-O&M	201,113	92,222	39,809	52,873	39,809	135,327	561,153	957,685			957,685
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	29,000	11,500	105,068	0	0	0	145,568	1,513,172	1,513,172		
	8a Oil Spill Cleanup/Response Equipment-O&M	28,384	25,150	15,150	40,150	23,300	15,984	148,118	276,344			276,344
	13 RCRA Corrective Action-O&M	11,667	11,667	11,667	11,667	11,665	0	58,333	64,978	64,978		
	14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	124,395	124,395		
	17a Disposal of Noncontainerized Liquid Waste-O&M	38,773	17,500	17,500	0	50,000	28,000	151,773	331,803			331,803
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	20,000	0	292,520	317,120	440,120	415,520	1,485,280	1,633,506		1,633,506	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	9,000	36,200	41,600	47,000	74,000	68,600	276,400	342,390	316,052		26,338
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
	20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
	NA Amortization of Gains on Sales of Emissions Allowances	(89,611)	(89,611)	(89,611)	(89,611)	(89,611)	(89,611)	(537,666)	(983,208)			(983,208)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
	22 Pipeline Integrity Management	75,000	0	0	15,000	115,000	100,000	305,000	414,465	414,465		
	23 SPCC - Spill Prevention, Control & Countermeasures	94,988	74,866	112,950	95,700	205,300	87,730	671,534	754,325	754,325		
	24 Manatee Reburn	30,000	30,000	30,000	41,667	55,803	17,441	204,911	499,997			499,997
	25 Pt. Everglades ESP Technology	231,200	311,200	298,297	191,200	191,200	191,212	1,414,309	1,991,699			1,991,699
	26 UST Replacement/Removal	0	0	0	0	0	0	0	0	0		
	27 Lowest Quality Water Source	17,557	20,079	20,079	20,079	20,079	19,083	116,956	246,103	246,103		
	28 CWA 316(b) Phase II Rule	86,674	60,382	46,570	37,487	31,250	24,400	286,763	385,137	385,137		
	29 SCR Consumables	51,553	24,500	24,500	24,500	24,500	24,500	174,053	361,930			361,930
	30 HBMP	1,482	1,482	1,482	1,482	1,482	4,417	11,827	19,999	19,999		
	31 CAIR Compliance	38,000	0	0	205,508	178,250	154,133	575,891	1,242,112			1,242,112
	32 BART	0	0	0	0	0	0	0	1,355			1,355
	34 St. Lucie Cooling Water System Inspection & Maintenance	716,172	458,912	977,366	825,876	710,877	706,000	4,395,203	4,996,865	4,996,865		
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0		
	36 Low Level Radioactive Waste	16,667	16,667	16,667	16,667	16,667	16,667	100,000	120,271	85,393		34,879
2	Total of O&M Activities	1,714,548	1,209,643	2,068,541	1,961,292	2,206,618	2,026,330	11,186,968	16,376,072	$ 8,662,315	$ 1,353,390	$ 6,360,367
3	Recoverable Costs Allocated to Energy	$ 686,755	$ 570,396	$ 495,496	$ 626,553	$ 635,594	$ 638,914	$ 3,653,708	$ 6,360,367			
4a	Recoverable Costs Allocated to CP Demand	$ 1,031,134	$ 662,589	$ 1,303,868	$ 1,040,962	$ 1,154,247	$ 995,239	$ 6,188,038	$ 8,662,315			
4b	Recoverable Costs Allocated to GCP Demand	$ (3,343)	$ (23,343)	$ 269,177	$ 293,777	$ 416,777	$ 392,177	$ 1,345,222	$ 1,353,390			
5	Retail Energy Jurisdictional Factor	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%					
6a	Retail CP Demand Jurisdictional Factor	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 677,011	$ 562,304	$ 488,466	$ 617,664	$ 626,576	$ 629,849	$ 3,601,870	$ 6,270,126			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 1,018,353	$ 654,376	$ 1,287,706	$ 1,028,059	$ 1,139,940	$ 982,903	$ 6,111,337	$ 8,554,946			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ (3,343)	$ (23,343)	$ 269,177	$ 293,777	$ 416,777	$ 392,177	$ 1,345,222	$ 1,353,390			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 1,692,021	$ 1,193,337	$ 2,045,349	$ 1,939,500	$ 2,183,293	$ 2,004,929	$ 11,058,429	$ 16,178,462			

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
January 2008 - December 2008

Variance Report of Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		(1) Estimated Actual	(2) Original Projections	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
2	Low NOx Burner Technology-Capital	$ 847,926	$ 848,325	$ (399)	0.0%
3b	Continuous Emission Monitoring Systems-Capital	1,055,168	1,020,109	35,059	3.4%
4b	Clean Closure Equivalency-Capital	3,840	3,840	0	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,702,928	1,700,056	2,872	0.2%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	1,560 0	1,558	2	0.1%
8b	Oil Spill Cleanup/Response Equipment-Capital	89,905	84,497	5,408	6.4%
10	Relocate Storm Water Runoff-Capital	9,560	9,560	0	0.0%
NA	SO2 Allowances-Negative Return on Investment	(279,207)	(204,972)	(74,235)	36.2%
12	Scherer Discharge Pipeline-Capital	62,796	62,796	(0)	0.0%
17b	Disposal of Noncontainerized Liquid Wate-Capital	0	0	0	NA
20	Wastewater Discharge Elimination & Reuse	240,966	240,966	0	0.0%
21	St. Lucie Turtle Net	120,632	119,525	1,107	0.9%
22	Pipeline Integrity Management	0	14,717	(14,717)	-100.0%
23	SPCC-Spill Prevention, Control & Countermeasures	2,122,237	2,144,722	(22,485)	-1.0%
24	Manatee Reburn	4,770,684	5,024,450	(253,766)	-5.1%
25	Pt. Everglades ESP Technology	11,569,509	11,903,263	(333,754)	-2.8%
26	UST Replacement/Removal	66,966	0	66,966	NA
31	CAIR Compliance	8,105,619	5,905,506	2,200,113	37.3%
33	CAMR Compliance	1,569,371	4,094,304	(2,524,933)	-61.7%
34	St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	NA
35	Martin Plant Drinking Water System Compliance	9,930	14,504	(4,574)	-31.5%
36	Low Level Radioactive Waste	0	0	0	NA
37	DeSoto Next Generation Solar Energy Center	29,115	0	29,115	NA
38	Space Coast Next Generation Solar Energy Center	4,681	0	4,681	NA
39	Martin Next Generation Solar Energy Center	81,892	0	81,892	NA
2	Total Investment Projects-Recoverable Costs	$ 32,186,076	$ 32,987,726	$ (801,650)	-2.4%
3	Recoverable Costs Allocated to Energy	$ 19,058,076	$ 19,698,602	$ (640,526)	-3.3%
4	Recoverable Costs Allocated to Demand	$ 13,127,999	$ 13,289,124	$ (161,125)	-1.2%

Notes:
Column(1) is the 12-Month Totals on Form 42-7E
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-07-0922-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2008 - December 2008

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of Investment Projects (A)							
2	Low NOx Burner Technology-Capital	72,973	72,559	72,144	71,730	71,315	70,869	431,591
3b	Continuous Emission Monitoring Systems-Capital	85,034	85,202	87,449	89,367	89,237	89,210	525,499
4b	Clean Closure Equivalency-Capital	326	325	324	323	322	321	1,941
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	143,912	143,504	143,097	142,690	142,282	141,875	857,360
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	131	131	131	131	130	130	786
8b	Oil Spill Cleanup/Response Equipment-Capital	7,094	7,123	7,051	7,007	6,963	7,039	42,277
10	Relocate Storm Water Runoff-Capital	804	802	801	800	799	797	4,803
NA	SO2 Allowances-Negative Return on Investment	-21,695	-21,523	-21,351	-21,179	-23,954	-26,562	-136,264
12	Scherer Discharge Pipeline-Capital	5,291	5,280	5,270	5,259	5,249	5,238	31,587
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,266	20,232	20,199	20,165	20,131	20,097	121,090
21	St. Lucie Turtle Net	7,647	7,638	7,629	7,620	9,556	11,509	51,599
22	Pipeline Integrity Management	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	173,891	173,504	173,119	172,733	172,346	171,959	1,037,552
24	Manatee Rebum	403,697	402,581	401,464	400,348	399,232	398,115	2,405,437
25	Pt. Everglades ESP Technology	973,786	972,153	971,222	970,480	969,187	966,759	5,823,587
26	UST Removal / Replacement	5,637	5,627	5,616	5,606	5,596	5,586	33,668
31	CAIR Compliance	257,519	303,271	343,703	389,502	470,279	567,643	2,331,917
33	CAMR Compliance	51,304	54,357	68,227	81,835	90,759	100,568	447,050
34	St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
36	Low Level Radioactive Waste	0	0	0	0	0	0	0
37	DeSoto Next Generation Solar Energy Center	0	0	0	0	0	0	0
38	Space Coast Next Generation Solar Energy Center	0	0	0	0	0	0	0
39	Martin Next Generation Solar Energy Center	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 2,187,616	$ 2,232,766	$ 2,286,096	$ 2,344,417	$ 2,429,429	$ 2,531,153	$ 14,011,478
3	Recoverable Costs Allocated to Energy	$ 1,565,627	$ 1,566,494	$ 1,570,557	$ 1,574,874	$ 1,576,126	$ 1,577,835	$ 9,431,513
4	Recoverable Costs Allocated to Demand	$ 621,989	$ 666,272	$ 715,539	$ 769,543	$ 853,303	$ 953,319	$ 4,579,965
5	Retail Energy Jurisdictional Factor	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	
6	Retail Demand Jurisdictional Factor	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,543,414	$ 1,544,269	$ 1,548,274	$ 1,552,530	$ 1,553,764	$ 1,555,449	$ 9,297,700
8	Jurisdictional Demand Recoverable Costs (C)	$ 614,279	$ 658,013	$ 706,670	$ 760,004	$ 842,727	$ 941,502	$ 4,523,195
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 2,157,693	$ 2,202,282	$ 2,254,944	$ 2,312,534	$ 2,396,491	$ 2,496,951	$ 13,820,895

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2008 - December 2008

Capital Investment Projects-Recoverable Costs
(In Dollars)

Line #	Project #	Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)										
2	Low NOx Burner Technology-Capital	70,424	70,010	69,596	69,182	68,768	68,355	416,335	847,926		847,926
3b	Continuous Emission Monitoring Systems-Capital	89,037	88,753	88,438	88,122	87,807	87,512	529,669	1,055,168		1,055,168
4b	Clean Closure Equivalency-Capital	319	318	317	316	315	314	1,899	3,840	3,545	295
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	141,468	141,380	141,292	140,884	140,476	140,068	845,568	1,702,928	1,571,933	130,995
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	130	129	129	129	129	128	774	1,560	1,440	120
8b	Oil Spill Cleanup/Response Equipment-Capital	7,262	7,401	7,862	8,282	8,323	8,498	47,628	89,905	82,989	6,916
10	Relocate Storm Water Runoff-Capital	796	795	793	792	791	790	4,757	9,560	8,825	735
NA	SO2 Allowances-Negative Return on Investment	-25,896	-25,067	-24,238	-23,409	-22,581	-21,752	-142,943	-279,207		-279,207
12	Scherer Discharge Pipeline-Capital	5,228	5,217	5,207	5,196	5,186	5,175	31,209	62,796	57,966	4,830
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,064	20,030	19,996	19,962	19,929	19,895	119,876	240,966	222,430	18,536
21	St. Lucie Turtle Net	11,518	11,513	11,508	11,503	11,498	11,493	69,033	120,632	111,353	9,279
22	Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	171,572	175,245	179,232	179,148	181,374	198,114	1,084,685	2,122,237	1,958,988	163,249
24	Manatee Reburn	396,999	395,882	394,766	393,650	392,533	391,417	2,365,247	4,770,684		4,770,684
25	Pt. Everglades ESP Technology	964,155	961,555	958,954	956,353	953,753	951,152	5,745,922	11,569,509		11,569,509
26	UST Removal / Replacement	5,575	5,565	5,555	5,545	5,534	5,524	33,298	66,966	61,815	5,151
31	CAIR Compliance	680,132	815,762	927,722	1,010,758	1,100,475	1,238,833	5,773,702	8,105,619	7,482,110	623,509
33	CAMR Compliance	119,355	143,021	164,633	183,078	209,688	302,546	1,122,321	1,569,371	1,448,650	120,721
34	St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0	0		
35	Martin Plant Drinking Water System Compliance	0	872	2,044	2,341	2,338	2,335	9,930	9,930	9,166	764
36	Low Level Radioactive Waste	0	0	0	0	0	0	0	0	0	0
37	DeSoto Next Generation Solar Energy Center	0	0	0	0	0	29,115	29,115	29,115	26,875	2,240
38	Space Coast Next Generation Solar Energy Center	0	0	0	0	0	4,681	4,681	4,681	4,321	360
39	Martin Next Generation Solar Energy Center	0	0	0	0	0	81,892	81,892	81,892	75,593	6,299
2	Total Investment Projects - Recoverable Costs	$2,658,138	$2,818,401	$2,953,806	$3,051,832	$3,166,336	$3,526,085	$18,174,598	$ 32,186,076	$ 13,127,999	$19,058,076
3	Recoverable Costs Allocated to Energy	$1,584,213	$1,593,231	$1,600,308	$1,604,508	$1,609,977	$1,634,330	$ 9,626,566	$ 19,058,076		
4	Recoverable Costs Allocated to Demand	$1,073,925	$1,225,170	$1,353,498	$1,447,324	$1,556,359	$1,891,755	$ 8,548,032	$ 13,127,999		
5	Retail Energy Jurisdictional Factor	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%				
6	Retail Demand Jurisdictional Factor	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%				
7	Jurisdictional Energy Recoverable Costs (B)	$1,561,736	$1,570,626	$1,577,603	$1,581,744	$1,587,134	$1,611,143	$ 9,489,986	$ 18,787,686		
8	Jurisdictional Demand Recoverable Costs (C)	$1,060,614	$1,209,984	$1,336,722	$1,429,384	$1,537,068	$1,868,306	$ 8,442,078	$ 12,965,273		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$2,622,350	$2,780,610	$2,914,325	$3,011,128	$3,124,202	$3,479,449	$17,932,064	$ 31,752,959		

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

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	($11,342)	($11,342)
	c. Retirements		$0	$0	$0	$0	$0	($11,342)	($11,342)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,462,051	n/a
3.	Less: Accumulated Depreciation (C)	$14,408,061	14,450,875	14,495,688	14,540,502	14,585,315	14,630,129	14,663,568	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,067,332	$3,022,518	$2,977,705	$2,932,891	$2,888,078	$2,843,265	$2,798,483	n/a
6.	Average Net Investment		3,044,925	3,000,112	2,955,298	2,910,485	2,865,671	2,820,874	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		23,398	23,053	22,709	22,365	22,020	21,676	$135,221
	b. Debt Component (Line 6 x 1.6767% x 1/12)		4,782	4,692	4,622	4,552	4,482	4,412	$27,521
8.	Investment Expenses								
	a. Depreciation (E)		44,813	44,813	44,813	44,813	44,813	44,782	$268,849
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$72,973	$72,559	$72,144	$71,730	$71,315	$70,869	$431,591

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-in-Service/Depreciation Base (B)	$17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	n/a
3.	Less: Accumulated Depreciation (C)	$14,663,568	14,708,318	14,753,068	14,797,818	14,842,568	14,887,319	14,932,069	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,798,483	$2,753,733	$2,708,982	$2,664,232	$2,619,482	$2,574,732	$2,529,982	n/a
6.	Average Net Investment		2,776,108	2,731,358	2,686,607	2,641,857	2,597,107	2,552,357	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		21,332	20,988	20,644	20,300	19,957	19,613	258,056
	b. Debt Component (Line 6 x 1.8767% x 1/12)		4,342	4,272	4,202	4,132	4,062	3,992	52,520
8.	Investment Expenses								
	a. Depreciation (E)		44,750	44,750	44,750	44,750	44,750	44,750	537,350
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$70,424	$70,010	$69,596	$69,182	$68,768	$68,355	$847,926

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$943	($235,355)	$165,941	$809	$4,880	$19,642	($43,140)
	c. Retirements		($30,957)	($332,083)	($279,786)	$0	($33,307)	$0	($676,133)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,474,967	12,475,910	12,240,554	12,406,495	12,407,304	12,412,184	12,431,827	n/a
3.	Less: Accumulated Depreciation (C)	$6,950,870	6,953,869	6,655,629	6,409,738	6,443,800	6,444,560	6,478,648	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,524,097	$5,522,041	$5,584,925	$5,996,758	$5,963,504	$5,967,624	$5,953,178	n/a
6.	Average Net Investment		5,523,069	5,553,483	5,790,841	5,980,131	5,965,564	5,960,401	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,440	42,674	44,498	45,952	45,840	45,801	$267,205
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,638	8,685	9,056	9,352	9,330	9,321	$54,382
8.	Investment Expenses								
	a. Depreciation (E)		33,956	33,843	33,895	34,062	34,067	34,088	$203,911
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,034	$85,202	$87,449	$89,367	$89,237	$89,210	$525,499

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$6,000	$0	$0	$0	$0	$3,000	$9,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,431,827	12,437,827	12,437,827	12,437,827	12,437,827	12,437,827	12,440,827	n/a
3.	Less: Accumulated Depreciation (C)	$6,478,648	6,512,760	6,546,875	6,580,991	6,615,106	6,649,222	6,683,345	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,953,178	$5,925,067	$5,890,951	$5,856,836	$5,822,720	$5,788,605	$5,757,482	n/a
6.	Average Net Investment		5,939,122	5,908,009	5,873,893	5,839,778	5,805,662	5,773,043	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		45,637	45,398	45,136	44,874	44,612	44,361	537,223
	b. Debt Component (Line 6 x 1.8767% x 1/12)		9,288	9,240	9,186	9,133	9,079	9,028	109,337
8.	Investment Expenses								
	a. Depreciation (E)		34,111	34,116	34,116	34,116	34,116	34,123	408,608
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$89,037	$88,753	$88,438	$88,122	$87,807	$87,512	$1,055,168

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	$35,581	35,692	35,802	35,913	36,024	36,135	36,246	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$23,285	$23,174	$23,063	$22,953	$22,842	$22,731	$22,620	n/a
6.	Average Net Investment		23,230	23,119	23,008	22,897	22,786	22,676	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		178	178	177	176	175	174	$1,058
	b. Debt Component (Line 6 x 1.8767% x 1/12)		36	36	36	36	36	35	$215
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	$665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$326	$325	$324	$323	$322	$321	$1,938

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	$36,246	36,358	36,467	36,578	36,689	36,800	36,910	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$22,620	$22,509	$22,399	$22,288	$22,177	$22,066	$21,955	n/a
6.	Average Net Investment		22,565	22,454	22,343	22,232	22,122	22,011	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		173	173	172	171	170	169	2,086
	b. Debt Component (Line 6 x 1.8767% x 1/12)		35	35	35	35	35	34	425
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	1,330
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$319	$318	$317	$316	$315	$314	$3,840

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	n/a
3.	Less: Accumulated Depreciation (C)	$2,729,709	2,773,756	2,817,802	2,861,849	2,905,895	2,949,942	2,993,988	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,820,508	$10,776,462	$10,732,415	$10,688,369	$10,644,322	$10,600,276	$10,556,229	n/a
6.	Average Net Investment		10,798,485	10,754,438	10,710,392	10,666,346	10,622,299	10,578,253	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		82,977	82,639	82,300	81,962	81,624	81,285	$492,787
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16,868	16,819	16,750	16,681	16,612	16,543	$100,293
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	$264,279
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$143,912	$143,504	$143,097	$142,690	$142,282	$141,875	$857,359

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$80,000	$0	$0	$0	$0	$80,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,217	13,550,217	13,610,217	13,610,217	13,610,217	13,610,217	13,610,217	n/a
3.	Less: Accumulated Depreciation (C)	$2,993,988	3,038,035	3,082,124	3,126,255	3,170,386	3,214,518	3,258,649	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,556,229	$10,512,183	$10,528,094	$10,483,962	$10,439,831	$10,395,700	$10,351,568	n/a
6.	Average Net Investment		10,534,206	10,520,138	10,506,028	10,461,897	10,417,765	10,373,634	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		80,947	80,839	80,730	80,391	80,052	79,713	975,458
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16,474	16,452	16,430	16,361	16,292	16,223	198,526
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,089	44,131	44,131	44,131	44,131	528,940
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$141,468	$141,380	$141,292	$140,884	$140,476	$140,068	$1,702,926

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$20,154	20,185	20,216	20,247	20,278	20,309	20,340	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,876	$10,845	$10,814	$10,783	$10,752	$10,721	$10,690	n/a
6.	Average Net Investment		10,860	10,829	10,798	10,767	10,736	10,705	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		83	83	83	83	83	82	$497
	b. Debt Component (Line 6 x 1.8787% x 1/12)		17	17	17	17	17	17	$101
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	$186
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$131	$131	$131	$131	$130	$130	$785

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$20,340	20,371	20,402	20,433	20,464	20,495	20,526	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,690	$10,659	$10,628	$10,597	$10,566	$10,535	$10,504	n/a
6.	Average Net Investment		10,674	10,643	10,612	10,581	10,550	10,519	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		82	82	82	81	81	81	986
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17	17	17	17	16	16	201
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	372
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$130	$129	$129	$129	$129	$128	$1,559

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Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$2,112	$0	($0)	$0	$9,270	$11,382
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$414,605	414,605	416,717	416,717	416,717	416,717	425,987	n/a
3.	Less: Accumulated Depreciation (C)	$154,046	158,752	163,520	168,251	172,983	177,714	182,522	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$260,559	$255,853	$253,196	$248,465	$243,734	$239,003	$243,465	n/a
6.	Average Net Investment		258,206	254,525	250,831	246,100	241,369	241,234	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,984	1,956	1,927	1,891	1,855	1,854	$11,467
	b. Debt Component (Line 6 x 1.8787% x 1/12)		404	398	392	385	377	377	$2,334
8.	Investment Expenses								
	a. Depreciation (E)		4,706	4,769	4,731	4,731	4,731	4,808	$28,476
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,094	$7,123	$7,051	$7,007	$6,963	$7,039	$42,277

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$31,898	$8,000	$31,000	$0	$20,000	$20,000	$110,898
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$425,987	457,885	465,885	496,885	496,885	516,885	536,885	n/a
3.	Less: Accumulated Depreciation (C)	$182,522	187,408	192,293	197,506	203,045	208,584	214,164	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$243,465	$270,477	$273,591	$299,379	$293,840	$308,301	$322,720	n/a
6.	Average Net Investment		256,971	272,034	286,485	296,609	301,070	315,510	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,975	2,090	2,201	2,279	2,313	2,424	24,750
	b. Debt Component (Line 6 x 1.8767% x 1/12)		402	425	448	464	471	493	5,037
8.	Investment Expenses								
	a. Depreciation (E)		4,886	4,886	5,212	5,539	5,539	5,580	60,119
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,262	$7,401	$7,862	$8,282	$8,323	$8,498	$89,906

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$45,687	45,825	45,962	46,100	46,237	46,374	46,512	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$72,107	$71,969	$71,832	$71,694	$71,557	$71,419	$71,282	n/a
6.	Average Net Investment		72,038	71,900	71,763	71,626	71,488	71,351	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		554	552	551	550	549	548	$3,305
	b. Debt Component (Line 6 x 1.6767% x 1/12)		113	112	112	112	112	112	$673
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	$825
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$804	$802	$801	$800	$799	$797	$4,803

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$46,512	46,649	46,787	46,924	47,061	47,199	47,336	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$71,282	$71,145	$71,007	$70,870	$70,732	$70,595	$70,457	n/a
6.	Average Net Investment		71,213	71,076	70,938	70,801	70,664	70,526	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		547	546	545	544	543	542	6,573
	b. Debt Component (Line 6 x 1.8767% x 1/12)		111	111	111	111	111	110	1,338
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	1,649
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$796	$795	$793	$792	$791	$790	$9,560

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-6A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$414,707	415,845	416,984	418,123	419,262	420,400	421,539	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$449,554	$448,415	$447,276	$446,136	$444,999	$443,860	$442,721	n/a
6.	Average Net Investment		448,984	447,846	446,707	445,568	444,429	443,291	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,460	3,441	3,433	3,424	3,415	3,406	$20,569
	b. Debt Component (Line 6 x 1.8767% x 1/12)		702	700	699	697	695	693	$4,186
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	$6,833
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,291	$5,280	$5,270	$5,259	$5,249	$5,238	$31,588

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$421,539	422,678	423,817	424,955	426,094	427,233	428,372	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$442,721	$441,583	$440,444	$439,305	$438,166	$437,028	$435,889	n/a
6.	Average Net Investment		442,152	441,013	439,874	438,736	437,597	436,458	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,398	3,389	3,380	3,371	3,363	3,354	40,823
	b. Debt Component (Line 6 x 1.8767% x 1/12)		691	690	688	686	684	683	8,308
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	13,665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,228	$5,217	$5,207	$5,196	$5,186	$5,175	$62,797

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	$562,996	566,645	570,294	573,943	577,591	581,240	584,889	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,798,665	$1,795,017	$1,791,368	$1,787,719	$1,784,070	$1,780,422	$1,776,773	n/a
6.	Average Net Investment		1,796,841	1,793,192	1,789,544	1,785,895	1,782,246	1,778,597	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,807	13,779	13,751	13,723	13,695	13,667	$82,423
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,810	2,804	2,799	2,793	2,787	2,782	$16,775
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	$21,892
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,266	$20,232	$20,199	$20,165	$20,131	$20,097	$121,090

Notes:

(A) N/A

(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.

(C) N/A

(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.

(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	$564,889	568,538	592,186	595,835	599,484	603,132	606,781	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,776,773	$1,773,124	$1,769,476	$1,765,827	$1,762,178	$1,758,529	$1,754,881	n/a
6.	Average Net Investment		1,774,949	1,771,300	1,767,651	1,764,002	1,760,354	1,756,705	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,839	13,811	13,783	13,755	13,727	13,699	163,836
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,776	2,770	2,764	2,759	2,753	2,747	33,344
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	43,785
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,064	$20,030	$19,996	$19,962	$19,929	$19,895	$240,965

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	($362,595)	$2,743	($359,851)
	c. Retirements		$0	$0	$0	$0	($828,789)	$0	($828,789)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	466,195	468,938	n/a
3.	Less: Accumulated Depreciation (C)	$105,991	106,958	107,925	108,892	109,859	(718,175)	(717,630)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$722,798	$721,831	$720,865	$719,898	$718,931	$1,184,370	$1,186,568	n/a
6.	Average Net Investment		722,315	721,348	720,381	719,414	951,650	1,185,469	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,550	5,543	5,536	5,528	7,313	9,109	$38,579
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,130	1,128	1,127	1,125	1,488	1,854	$7,852
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	755	545	$5,169
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,647	$7,638	$7,629	$7,620	$9,556	$11,509	$51,599

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.8640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$468,938	468,938	468,938	468,938	468,938	468,938	468,938	n/a
3.	Less: Accumulated Depreciation (C)	($717,630)	(717,083)	(716,536)	(715,989)	(715,441)	(714,894)	(714,347)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,186,568	$1,186,021	$1,185,474	$1,184,927	$1,184,380	$1,183,832	$1,183,285	n/a
6.	Average Net Investment		1,186,294	1,185,747	1,185,200	1,184,653	1,184,106	1,183,559	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		9,116	9,111	9,107	9,103	9,099	9,095	93,210
	b. Debt Component (Line 6 x 1.6767% x 1/12)		1,855	1,854	1,854	1,853	1,852	1,851	18,970
8.	Investment Expenses								
	a. Depreciation (E)		547	547	547	547	547	547	8,451
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,518	$11,513	$11,508	$11,503	$11,498	$11,493	$120,631

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$231	$0	$0	$0	$231
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,849,669	15,849,669	15,849,669	15,849,900	15,849,900	15,849,900	15,849,900	n/a
3.	Less: Accumulated Depreciation (C)	$1,549,691	1,591,528	1,633,366	1,675,203	1,717,041	1,758,879	1,800,716	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$14,299,978	$14,258,141	$14,216,303	$14,174,696	$14,132,858	$14,091,021	$14,049,183	n/a
6.	Average Net Investment		14,279,059	14,237,222	14,195,500	14,153,777	14,111,940	14,070,102	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		109,723	109,401	109,081	108,760	108,439	108,117	$653,520
	b. Debt Component (Line 6 x 1.8767% x 1/12)		22,331	22,266	22,200	22,135	22,070	22,004	$133,006
8.	Investment Expenses								
	a. Depreciation (E)		41,837	41,837	41,838	41,838	41,838	41,838	$251,026
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$173,891	$173,504	$173,119	$172,733	$172,346	$171,959	$1,037,552

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$646,200	$80,888	$0	$399,800	$2,546,840	$3,653,728
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,849,900	15,849,900	16,496,100	16,556,988	16,556,988	16,956,788	19,503,628	n/a
3.	Less: Accumulated Depreciation (C)	$1,800,716	1,842,554	1,885,469	1,929,503	1,973,578	2,018,443	2,066,853	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$14,049,183	$14,007,345	$14,610,631	$14,627,485	$14,583,410	$14,938,345	$17,436,775	n/a
6.	Average Net Investment		14,028,264	14,308,988	14,619,058	14,605,447	14,760,877	16,187,560	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		107,796	109,953	112,335	112,231	113,425	124,388	1,333,647
	b. Debt Component (Line 6 x 1.6767% x 1/12)		21,939	22,378	22,863	22,841	23,085	25,316	271,427
8.	Investment Expenses								
	a. Depreciation (E)		41,838	42,915	44,034	44,075	44,865	48,410	517,162
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$171,572	$175,245	$179,232	$179,148	$181,374	$198,114	$2,122,236

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$22	$0	$22
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$32,862,547	32,862,547	32,862,547	32,862,547	32,862,547	32,862,568	32,862,568	n/a
3.	Less: Accumulated Depreciation (C)	$2,203,935	2,324,657	2,445,380	2,566,103	2,686,825	2,807,548	2,928,271	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$30,658,612	$30,537,889	$30,417,167	$30,296,444	$30,175,721	$30,055,020	$29,934,297	n/a
6.	Average Net Investment		30,598,251	30,477,528	30,356,805	30,236,083	30,115,371	29,994,659	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		235,122	234,194	233,267	232,339	231,412	230,484	$1,396,818
	b. Debt Component (Line 6 x 1.8767% x 1/12)		47,853	47,664	47,475	47,286	47,097	46,909	$284,284
8.	Investment Expenses								
	a. Depreciation (E)		120,723	120,723	120,723	120,723	120,723	120,723	$724,336
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$403,697	$402,581	$401,464	$400,348	$399,232	$398,115	$2,405,438

Notes:

(A) N/A

(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.

(C) N/A

(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.

(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	n/a
3.	Less: Accumulated Depreciation (C)	$2,928,271	3,048,994	3,169,716	3,290,439	3,411,162	3,531,885	3,652,607	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$29,934,297	$29,813,575	$29,692,852	$29,572,129	$29,451,406	$29,330,684	$29,209,961	n/a
6.	Average Net Investment		29,873,936	29,753,213	29,632,491	29,511,768	29,391,045	29,270,322	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		229,556	228,629	227,701	226,773	225,846	224,918	2,760,241
	b. Debt Component (Line 6 x 1.8767% x 1/12)		46,720	46,531	46,342	46,153	45,965	45,776	561,771
8.	Investment Expenses								
	a. Depreciation (E)		120,723	120,723	120,723	120,723	120,723	120,723	1,448,673
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$396,999	$395,882	$394,766	$393,650	$392,533	$391,417	$4,770,685

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$2,868	$153,940	$119,067	$184,499	$28,753	($481)	$488,646
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$80,951,062	80,953,930	81,107,869	81,226,936	81,411,435	81,440,189	81,439,708	n/a
3.	Less: Accumulated Depreciation (C)	$5,768,551	6,048,324	6,328,328	6,608,730	6,889,581	7,170,752	7,451,964	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$75,182,510	$74,905,605	$74,779,542	$74,618,206	$74,521,854	$74,269,437	$73,987,743	n/a
6.	Average Net Investment		75,044,057.76	74,842,573	74,698,874	74,570,030	74,395,645	74,128,590	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		576,651.12	575,103	573,999	573,009	571,669	569,617	$3,440,046
	b. Debt Component (Line 6 x 1.8767% x 1/12)		117,361	117,046	116,822	116,620	116,347	115,930	$700,126
8.	Investment Expenses								
	a. Depreciation (E)		279,773	280,003	280,402	280,851	281,171	281,213	$1,683,413
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$973,786	$972,153	$971,222	$970,480	$969,187	$966,759	$5,823,586

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-6A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-6A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-6A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$81,439,708	81,439,708	81,439,708	81,439,708	81,439,708	81,439,708	81,439,708	n/a
3.	Less: Accumulated Depreciation (C)	$7,451,964	7,733,176	8,014,388	8,295,600	8,576,812	8,858,024	9,139,236	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$73,987,743	$73,706,532	$73,425,320	$73,144,108	$72,862,896	$72,581,684	$72,300,472	n/a
6.	Average Net Investment		73,847,137	73,565,926	73,284,714	73,003,502	72,722,290	72,441,078	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		567,454	565,293	563,132	560,971	558,810	556,649	6,812,356
	b. Debt Component (Line 6 x 1.8767% x 1/12)		115,490	115,050	114,610	114,170	113,730	113,291	1,386,467
8.	Investment Expenses								
	a. Depreciation (E)		281,212	281,212	281,212	281,212	281,212	281,212	3,370,684
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$964,155	$961,555	$958,954	$956,353	$953,753	$951,152	$11,569,507

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-in-Service/Depreciation Base (B)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$2,773	3,882	4,991	6,100	7,209	8,318	9,427	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$490,144	$489,035	$487,926	$486,817	$485,708	$484,598	$483,489	n/a
6.	Average Net Investment		489,589	488,480	487,371	486,262	485,153	484,044	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,762	3,754	3,745	3,737	3,728	3,719	$22,445
	b. Debt Component (Line 6 x 1.6767% x 1/12)		766	764	762	760	759	757	$4,568
8.	Investment Expenses								
	a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	$6,654
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,637	$5,627	$5,616	$5,606	$5,596	$5,586	$33,667

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$9,427	10,536	11,645	12,754	13,863	14,972	16,081	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$483,489	$482,380	$481,271	$480,162	$479,053	$477,944	$476,835	n/a
6.	Average Net Investment		482,935	481,826	480,717	479,608	478,499	477,390	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,711	3,702	3,694	3,685	3,677	3,668	44,583
	b. Debt Component (Line 6 x 1.8767% x 1/12)		755	754	752	750	748	747	9,074
8.	Investment Expenses								
	a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	13,309
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,575	$5,565	$5,555	$5,545	$5,534	$5,524	$66,965

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$3,387,815	$6,461,418	$2,644,701	$7,667,806	$9,793,209	$11,256,143	$41,211,094
	b. Clearings to Plant		($1,225)	$217,760	$21,966	$1,695	$5,672	$839	$246,907
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$57,722	56,497	274,258	296,224	297,919	303,791	304,630	n/a
3.	Less: Accumulated Depreciation (C)	$75	222	586	1,188	1,813	2,446	3,085	n/a
4.	CWIP - Non Interest Bearing	$26,078,873	29,466,688	35,710,636	37,920,051	45,587,860	55,381,068	66,637,211	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$26,136,521	$29,522,963	$35,984,306	$38,215,087	$45,883,965	$55,682,413	$66,938,756	n/a
6.	Average Net Investment		27,829,742	32,753,636	37,099,696	42,049,526	50,783,189	61,310,585	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		213,848	251,684	285,080	323,116	390,227	471,121	$1,935,076
	b. Debt Component (Line 6 x 1.8767% x 1/12)		43,523	51,223	58,020	65,761	79,420	95,884	$393,631
8.	Investment Expenses								
	a. Depreciation (E)		148	364	602	625	633	639	$3,010
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$257,519	$303,271	$343,703	$389,502	$470,279	$567,643	$2,331,917

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$13,070,992	$11,140,549	$7,936,852	$9,884,454	$8,888,169	$18,153,571	$69,074,587
	b. Clearings to Plant		$0	$24,846,411	$262,831	$699,289	$3,359,307	$17,529,997	$46,697,834
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$304,630	304,630	25,151,040	25,413,871	26,113,160	29,472,467	47,002,464	n/a
3.	Less: Accumulated Depreciation (C)	$3,065	3,724	28,175	76,689	126,286	179,270	246,124	n/a
4.	CWIP - Non Interest Bearing	$66,637,211	79,708,203	66,002,342	73,676,363	82,861,528	88,390,390	89,013,965	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$66,938,756	$80,009,108	$91,125,207	$99,013,544	$108,848,402	$117,683,587	$135,770,305	n/a
6.	Average Net Investment		73,473,932	85,567,158	95,069,376	103,930,973	113,265,995	126,726,946	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		564,586	657,512	730,529	798,623	870,355	973,791	6,530,473
	b. Debt Component (Line 6 x 1.8767% x 1/12)		114,906	133,818	148,679	162,538	177,137	198,188	1,329,097
8.	Investment Expenses								
	a. Depreciation (E)		640	24,451	48,514	49,597	52,984	66,854	246,049
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$680,132	$815,782	$927,722	$1,010,758	$1,100,475	$1,238,833	$8,105,619

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		($844,456)	$1,504,735	$1,494,882	$1,447,972	$482,000	$1,639,243	$5,724,376
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$5,969,718	5,125,262	6,629,996	8,124,879	9,572,851	10,054,851	11,694,093	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,969,718	$5,125,262	$6,629,996	$8,124,879	$9,572,851	$10,054,851	$11,694,093	n/a
6.	Average Net Investment		5,547,490	5,877,629	7,377,437	8,848,865	9,813,851	10,874,472	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,628	45,165	56,689	67,996	75,411	83,561	$371,451
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,676	9,192	11,538	13,839	15,348	17,007	$75,599
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$51,304	$54,357	$68,227	$81,835	$90,759	$100,568	$447,049

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$2,423,749	$2,694,173	$1,979,626	$2,009,383	$3,745,317	$16,336,332	$29,188,580
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$11,694,093	14,117,842	16,812,015	18,791,641	20,801,024	24,546,341	40,882,673	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$11,694,093	$14,117,842	$16,812,015	$18,791,641	$20,801,024	$24,546,341	$40,882,673	n/a
6.	Average Net Investment		12,905,968	15,464,929	17,801,828	19,796,333	22,673,683	32,714,507	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		99,172	118,835	136,792	152,118	174,228	251,384	1,303,960
	b. Debt Component (Line 6 x 1.8767% x 1/12)		20,184	24,186	27,840	30,959	35,459	51,182	265,369
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$119,355	$143,021	$164,633	$183,078	$209,688	$302,546	$1,569,369

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: St. Lucie Cooling Water System Inspect & Maintenance (Project No. 34)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: St. Lucie Cooling Water System Inspect & Maintenance (Project No. 34)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (Project No. 35)
(In Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$163,712	$56,288	$0	$0	$0	$220,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	163,712	220,000	220,000	220,000	220,000	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	116	388	699	1,011	1,323	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$163,596	$219,612	$219,301	$218,989	$218,677	n/a
6.	Average Net Investment		0	81,798	191,604	219,456	219,145	218,833	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	629	1,472	1,686	1,684	1,682	7,153
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	128	300	343	343	342	1,456
8.	Investment Expenses								
	a. Depreciation (E)		0	116	272	312	312	312	1,323
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$872	$2,044	$2,341	$2,338	$2,335	$9,931

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(In Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Desoto (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Desoto (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$6,296,363	$6,296,363
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	6,296,363	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$6,296,363	n/a
6.	Average Net Investment		0	0	0	0	0	3,148,182	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	24,191	24,191
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	4,923	4,923
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$29,115	$29,115

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Space Coast (Project No. 38)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Space Coast (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$1,012,286	$1,012,286
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	1,012,286	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$1,012,286	n/a
6.	Average Net Investment		0	0	0	0	0	506,143	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	3,889	3,889
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	792	792
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$4,681	$4,681

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Martin (Project No. 39)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Martin (Project No. 39)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$17,710,000	$17,710,000
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	17,710,000	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$17,710,000	n/a
6.	Average Net Investment		0	0	0	0	0	8,855,000	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	68,043	68,043
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	13,848	13,848
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$81,892	$81,892

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 51-53.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 51-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 51-53.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount	
1	Working Capital Dr (Cr)									
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b 158.200 Allowances Withheld	0	0	0	0	0	0	0		
	c 182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
	d 254.900 Other Regulatory Liabilities-Gains	(2,355,248)	(2,336,640)	(2,318,032)	(2,299,424)	(2,280,816)	(2,899,518)	(2,844,918)		
2	Total Working Capital	($2,355,248)	($2,336,640)	($2,318,032)	($2,299,424)	($2,280,816)	($2,899,518)	($2,844,918)		
3	Average Net Working Capital Balance		(2,345,944)	(2,327,336)	(2,308,728)	(2,290,120)	(2,590,167)	(2,872,218)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(18,027)	(17,884)	(17,741)	(17,598)	(19,903)	(22,071)		
	b Debt Component (Line 6 x 1.6698% x 1/12)		(3,669)	(3,640)	(3,611)	(3,582)	(4,051)	(4,492)		
5	Total Return Component		($21,695)	($21,523)	($21,351)	($21,179)	($23,954)	($26,562)	($136,266)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(18,608)	(18,608)	(18,608)	(18,608)	(281,499)	(89,611)		
	b 411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
	c 509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)		($18,608)	($18,608)	($18,608)	($18,608)	($281,499)	($89,611)	($445,542)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(40,303)	(40,131)	(39,959)	(39,787)	(305,453)	(116,174)		
	a Recoverable Costs Allocated to Energy		(40,303)	(40,131)	(39,959)	(39,787)	(305,453)	(116,174)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%		
10	Demand Jurisdictional Factor		98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%		
11	Retail Energy-Related Recoverable Costs (B)		(39,731)	(39,562)	(39,392)	(39,223)	(301,119)	(114,525)		
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($39,731)	($39,562)	($39,392)	($39,223)	($301,119)	($114,525)		

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.2013% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount	
1	Working Capital Dr (Cr)									
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b 158.200 Allowances Withheld	$0	0	0	0	0	0	0		
	c 182.300 Other Regulatory Assets-Losses	$0	0	0	0	0	0	0		
	d 254.900 Other Regulatory Liabilities-Gains	($2,844,918)	(2,755,307)	(2,665,695)	(2,576,084)	(2,486,473)	(2,396,862)	(2,307,251)		
2	Total Working Capital	($2,844,918)	($2,755,307)	($2,665,695)	($2,576,084)	($2,486,473)	($2,396,862)	($2,307,251)		
3	Average Net Working Capital Balance		(2,800,112)	(2,710,501)	(2,620,890)	(2,531,279)	(2,441,668)	(2,352,056)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(21,517)	(20,828)	(20,139)	(19,451)	(18,762)	(18,074)		
	b Debt Component (Line 6 x 1.6696% x 1/12)		(4,379)	(4,239)	(4,099)	(3,959)	(3,819)	(3,678)		
5	Total Return Component		($25,896)	($25,067)	($24,238)	($23,409)	($22,581)	($21,752)	($279,209)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(89,611)	(89,611)	(89,611)	(89,611)	(89,611)	(89,611)		
	b 411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
	c 509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)		($89,611)	($89,611)	($89,611)	($89,611)	($89,611)	($89,611)	($983,208)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(115,507)	(114,678)	(113,849)	(113,021)	(112,192)	(111,363)		
	a Recoverable Costs Allocated to Energy		(115,507)	(114,678)	(113,849)	(113,021)	(112,192)	(111,363)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%		
10	Demand Jurisdictional Factor		98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%		
11	Retail Energy-Related Recoverable Costs (B)		(113,868)	(113,051)	(112,234)	(111,417)	(110,600)	(109,783)		
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($113,868)	($113,051)	($112,234)	($111,417)	($110,600)	($109,783)	($670,953)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.2013% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
2008 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/07	Estimated Balance 12/31/2008
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	2,700,574.97	2,689,282.57
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	2,416,089.59	2,416,089.59
02 - Low NOX Burner Technology Total					17,473,393.17	17,462,050.77
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	59,227.10	59,227.10
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.30%	26,354.96	37,385.86
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.40%	494,606.87	407,386.53
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.10%	511,705.24	347,150.58
	02 - Steam Generation Plant	Cutler Comm	31100	0.00%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	0.50%	36,276.52	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	0.20%	310,454.41	310,454.41
	02 - Steam Generation Plant	Cutler U6	31200	1.00%	311,861.95	311,861.95
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	477,896.88	477,896.88
	02 - Steam Generation Plant	Manatee U2	31100	4.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	508,734.36	508,551.98
	02 - Steam Generation Plant	Martin Comm	31200	4.10%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.50%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.80%	524,263.86	531,413.18
	02 - Steam Generation Plant	Martin U2	31100	1.50%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.50%	520,421.20	527,263.77
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.20%	51,132.85	67,787.69
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	461,988.64	458,612.69
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	475,113.36	480,873.50
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	512,296.04	508,210.30
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	517,303.41	517,303.41
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.40%	11,495.25	11,495.25
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	449,392.38	453,591.19
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	433,421.96	437,621.87
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	434,357.43	434,357.43
	02 - Steam Generation Plant	Scherer U4	31200	1.90%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	66,188.18	0.00
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	107,594.02	220,702.83
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	107,562.94	216,142.08
	02 - Steam Generation Plant	Turkey Pt Comm Fall	31100	2.30%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm Fall	31200	2.10%	37,954.50	37,954.50
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	543,842.20	545,683.81
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	502,946.49	504,788.03
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.10%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	5.00%	463,054.20	463,054.20
	05 - Other Generation Plant	FtLauderdale U5	34300	3.70%	474,559.99	474,559.99
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.50%	4,970.69	21,625.54
	05 - Other Generation Plant	Martin U3	34300	5.80%	411,933.88	413,342.64
	05 - Other Generation Plant	Martin U4	34300	5.70%	404,560.55	405,944.43
	05 - Other Generation Plant	Martin U8	34300	5.50%	13,876.71	4,688.46
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	6.30%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.20%	332,065.69	332,065.69
	05 - Other Generation Plant	Putnam U2	34300	5.40%	365,469.22	365,469.22
	05 - Other Generation Plant	Sanford U4	34300	5.60%	98,339.95	98,339.95
	05 - Other Generation Plant	Sanford U5	34300	5.70%	56,521.05	56,521.05
03 - Continuous Emission Monitoring Total					12,474,967.00	12,440,826.58
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	17,254.20	17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm Fall	31100	2.30%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					58,865.78	58,865.78

Florida Power & Light Company
Environmental Cost Recovery Clause
2008 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/07	Estimated Balance 12/31/2008
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	1,110,450.32	1,170,450.32
	02 - Steam Generation Plant	Martin U1	31100	1.50%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.30%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	68,893.65	68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					13,550,217.48	13,610,217.48
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					31,030.00	31,030.00
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31670	7-Year	343,854.35	456,862.61
	02 - Steam Generation Plant	Martin Comm	31600	3.20%	23,107.32	23,107.32
	05 - Other Generation Plant	Amortizable	34650	5-Year	0.00	9,271.59
	05 - Other Generation Plant	Amortizable	34670	7-Year	45,699.54	45,699.54
	08 - General Plant	Amortizable	39190	3-Year	1,943.47	1,943.47
08 - Oil Spill Clean-up/Response Equipment Total					414,604.68	536,884.53
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					117,793.83	117,793.83
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	9,936.72
		Scherer Comm	31100	1.60%	524,872.97	524,872.97
		Scherer Comm	31200	1.60%	328,761.62	328,761.62
		Scherer Comm	31400	1.00%	689.11	689.11
12 - Scherer Discharge Pipline Total					864,260.42	864,260.42
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.80%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.50%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	560,786.81	560,786.81
20 - Wastewater/Stormwater Discharge Elimination Total					2,361,661.78	2,361,661.78
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	828,789.34	468,938.12
21 - St. Lucie Turtle Nets Total					828,789.34	468,938.12
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	665,907.33	665,907.33
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	13,451.85	13,451.85
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.90%	13,450.30	13,450.30
	02 - Steam Generation Plant	CapeCanaveral U1	31100	2.00%	0.00	30,444.00
	02 - Steam Generation Plant	CapeCanaveral U2	31100	1.30%	0.00	30,444.00
	02 - Steam Generation Plant	Cutler Comm	31400	0.00%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	336,763.43	711,563.43
	02 - Steam Generation Plant	Manatee Comm	31500	3.70%	5,000.00	5,000.00
	02 - Steam Generation Plant	Manatee U1	31500	3.60%	0.00	10,935.00
	02 - Steam Generation Plant	Manatee U2	31500	3.60%	0.00	10,935.00
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	0.00	45,303.00
	02 - Steam Generation Plant	Martin U1	31100	1.50%	0.00	182,507.50
	02 - Steam Generation Plant	Martin U2	31100	1.50%	0.00	182,507.50
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	10,379.00	1,985,476.00
	02 - Steam Generation Plant	PtEverglades U3	31100	2.60%	0.00	32,500.00
	02 - Steam Generation Plant	PtEverglades U4	31100	2.60%	0.00	32,500.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	736,958.97	736,958.97

Florida Power & Light Company
Environmental Cost Recovery Clause
2008 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/07	Estimated Balance 12/31/2008
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	894,298.77	894,298.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	213,687.21	859,687.21
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm Fall	31500	2.10%	13,559.00	13,559.00
	02 - Steam Generation Plant	Turkey Pt U1	31100	2.50%	0.00	12,500.00
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	0.00	12,500.00
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	404,549.02	404,549.02
	03 - Nuclear Generation Plant	StLucie U1	32400	1.70%	437,714.57	437,945.38
	03 - Nuclear Generation Plant	StLucie U2	32300	1.90%	396,779.37	396,779.37
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	7,065.10
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.80%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.10%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.90%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.50%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	4.80%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.40%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34300	5.50%	0.00	74,555.00
	05 - Other Generation Plant	PtEvergiades GTs	34100	1.50%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEvergiades GTs	34200	5.10%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.20%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	2.50%	951,562.91	951,562.91
	06 - Transmission Plant - Electric		35300	2.80%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	2.60%	2,862,093.44	2,862,093.44
	08 - General Plant		39000	2.70%	12,843.35	12,843.35
23 - Spill Prevention Clean-Up & Countermeasures Total					**15,849,668.71**	**19,503,627.52**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	16,771,308.37	16,771,308.37
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	16,091,238.26	16,091,259.94
24 - Manatee Reburn Total					**32,862,546.63**	**32,862,568.31**
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEvergiades U1	31100	2.60%	298,709.93	298,709.93
	02 - Steam Generation Plant	PtEvergiades U1	31200	6.70%	10,404,603.15	10,404,603.15
	02 - Steam Generation Plant	PtEvergiades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	PtEvergiades U1	31600	1.00%	307,032.30	307,032.30
	02 - Steam Generation Plant	PtEvergiades U2	31100	2.60%	184,084.01	184,084.01
	02 - Steam Generation Plant	PtEvergiades U2	31200	6.10%	11,979,735.29	11,979,735.29
	02 - Steam Generation Plant	PtEvergiades U2	31500	2.10%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	PtEvergiades U2	31600	1.70%	324,086.94	324,086.94
	02 - Steam Generation Plant	PtEvergiades U3	31100	2.60%	4,812,793.71	4,858,902.04
	02 - Steam Generation Plant	PtEvergiades U3	31200	4.00%	16,040,755.59	16,194,431.96
	02 - Steam Generation Plant	PtEvergiades U3	31500	2.20%	2,404,282.44	2,427,316.36
	02 - Steam Generation Plant	PtEvergiades U4	31200	3.60%	24,864,782.55	25,123,410.25
	02 - Steam Generation Plant	PtEvergiades U4	31500	2.10%	2,875,365.39	2,882,565.18
25 - PPE ESP Technology Total					**80,951,061.78**	**81,439,707.89**
26 - UST Remove/Replace						
	08 - General Plant		39000	2.70%	492,916.42	492,916.42
26 - UST Remove/Replace Total					**492,916.42**	**492,916.42**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee U1	31400	3.70%	0.00	275,727.61
	02 - Steam Generation Plant	Martin U1	31200	1.80%	0.00	11,784,716.57
	02 - Steam Generation Plant	Martin U1	31400	1.30%	0.00	8,864,406.30
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	0.00	4,189.46
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	0.00	25,797,452.64
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.20%	0.00	110,241.49
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	57,722.33	57,855.15
	05 - Other Generation Plant	PtEvergiades GTs	34300	2.60%	0.00	107,874.32
31 - Clean Air Interstate Rule (CAIR) Total					**57,722.33**	**47,002,463.74**
35 - Martin Drinking Water System						
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	0.00	220,000.00
35 - Martin Drinking Water System Total					**0.00**	**220,000.00**
Grand Total					**178,389,499.35**	**229,473,813.17**

APPENDIX I

ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS 42-1P THROUGH 42-7P
JANUARY 2009 – DECEMBER 2009

KMD-3
DOCKET NO. 080007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _____
PAGES 1-109

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 5
COMPANY Florida Power & Light Co. (Direct)
WITNESS Korel M. Dubin (KMD-3)
DATE 11-04-03

Form 42-1P

Florida Power & Light Company
Environmental Cost Recovery Clause
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2009 to December 2009

Line No.		Energy ($)	CP Demand ($)	GCP Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period				
	a Projected O&M Activities (FORM 42-2P, Page 2 of 2, Lines 7 through 9)	7,551,764	6,226,789	2,413,172	16,191,725
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	21,605,195	53,280,423	0	74,885,618
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	29,156,959	59,507,212	2,413,172	91,077,343
2	True-up for Estimated Over/(Under) Recovery for the current period January 2008 - December 2008 (FORM 42-1E, Line 4, filed on August 4, 2008)	(2,994,900)	(2,572,131)	(161,546)	(5,728,576)
3	Final True-up Over/(Under) for the period January 2007 - December 2007 (FORM 42-1A, Line 7, filed on April 2, 2008)	1,833,204	1,283,719	57,456	3,174,379
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2009 - December 2009 (Line 1 - Line 2 - Line 3)	30,318,655	60,795,624	2,517,262	93,631,540
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.00072)	30,340,484	60,839,397	2,519,074	93,698,955

Notes:
Allocation to energy and demand in each period are in proportion to the respective period split of costs.
True-up costs are split in proportion to the split of actual demand-related and energy-related costs from respective true-up periods.
Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2009 - December 2009

O&M Activities
(in Dollars)

Line #	Project #	Projected JAN	Projected FEB	Projected MAR	Projected APR	Projected MAY	Projected JUN	6-Month Sub-Total
1	Description of O&M Activities							
	1 Air Operating Permit Fees-O&M	$163,175	$163,175	$163,175	$163,175	$163,175	$163,175	$979,050
	3a Continuous Emission Monitoring Systems-O&M	160,902	80,609	130,609	80,609	36,609	56,609	545,947
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	0	39,500	120,000	272,500	148,072	125,000	705,072
	8a Oil Spill Cleanup/Response Equipment-O&M	15,150	15,150	30,150	15,150	25,150	40,150	140,900
	13 RCRA Corrective Action-O&M	4,167	4,167	4,167	4,167	4,167	4,167	25,002
	14 NPDES Permit Fees-O&M	124,900	0	0	0	0	0	124,900
	17a Disposal of Noncontainerized Liquid Waste-O&M	32,500	32,500	30,000	30,000	30,000	30,000	185,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	223,524	223,524	223,524	223,524	223,524	223,524	1,341,144
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	59,809	59,809	59,809	59,809	59,809	59,809	358,854
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
	20 Wastewater Discharge Elimination &Reuse	0	0	0	0	0	0	0
	NA Amortization of Gains on Sales of Emissions Allowances	(18,608)	(18,608)	(18,608)	(18,608)	(281,499)	(89,611)	(445,542)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0
	22 Pipeline Integrity Management	0	0	40,000	0	0	0	40,000
	23 SPCC - Spill Prevention, Control & Countermeasures	37,500	104,166	114,166	104,168	37,500	45,500	443,000
	24 Manatee Rebum	41,667	41,667	41,667	41,667	41,667	41,667	250,002
	25 Pt. Everglades ESP Technology	189,693	189,693	189,693	189,693	189,693	189,693	1,138,158
	26 UST Replacement/Removal	0	0	0	0	0	0	0
	27 Lowest Quality Water Source	21,539	21,539	21,539	21,539	21,539	21,539	129,234
	28 CWA 316(b) Phase II Rule	43,917	43,917	43,917	43,917	43,917	43,917	263,502
	29 SCR Consumables	29,166	29,166	29,166	29,166	29,166	29,166	174,996
	30 HBMP	3,333	3,333	3,333	3,333	3,333	3,333	19,998
	31 CAIR Compliance	76,026	76,026	180,334	242,334	76,334	76,334	727,388
	32 BART	0	0	0	0	0	0	0
	34 St. Lucie Cooling Water System Inspection & Maintenance	15,000	15,000	500,000	520,000	750,000	0	1,800,000
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
	36 Low-Level Radioactive Waste Storage	83,333	83,333	83,333	83,333	83,333	83,333	500,000
	37 DeSoto Next Generation Solar Energy Center	0	0	0	0	0	0	0
	38 Space Coast Next Generation Solar Energy Center	0	0	0	0	0	0	0
	39 Martin Next Generation Solar Energy Center	0	0	0	0	0	0	0
	40 Greenhouse Gas Reduction Program			15,000	5,000	5,000	5,000	30,000
2	Total of O&M Activities	$1,260,008	$1,160,981	$ 1,958,289	$ 2,067,791	$ 1,643,803	$1,105,619	$ 9,196,489
3	Recoverable Costs Allocated to Energy	$ 716,643	$ 636,350	$ 818,158	$ 805,158	$ 342,267	$ 569,155	$ 3,887,730
4a	Recoverable Costs Allocated to CP Demand	$ 343,184	$ 324,450	$ 939,950	$ 1,062,452	$ 1,101,356	$ 336,284	$ 4,107,674
4b	Recoverable Costs Allocated to GCP Demand	$ 200,181	$ 200,181	$ 200,181	$ 200,181	$ 200,181	$ 200,181	$ 1,201,086
5	Retail Energy Jurisdictional Factor	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	
6a	Retail CP Demand Jurisdictional Factor	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 707,274	$ 628,030	$ 807,461	$ 794,631	$ 337,792	$ 561,714	$ 3,836,902
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 338,953	$ 320,450	$ 928,363	$ 1,049,355	$ 1,087,779	$ 332,138	$ 4,057,038
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 200,181	$ 200,181	$ 200,181	$ 200,181	$ 200,181	$ 200,181	$ 1,201,086
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,246,408	$1,148,661	$ 1,936,005	$ 2,044,167	$ 1,625,752	$1,094,033	$ 9,095,026

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2009 - December 2009

O&M Activities
(in Dollars)

Line #	Project #	Projected JUL	Projected AUG	Projected SEP	Projected OCT	Projected NOV	Projected DEC	6-Month Sub-Total	12-Month Total	Method of Classification CP Demand	GCP Demand	Energy
1	Description of O&M Activities											
	1 Air Operating Permit Fees-O&M	$163,175	$163,175	$163,175	$163,175	$163,175	$163,175	$979,050	$1,958,100			$1,958,100
	3a Continuous Emission Monitoring Systems-O&M	160,902	36,609	36,609	102,609	80,609	36,609	453,947	999,894			999,894
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	130,500	0	8,000	224,000	0	0	362,500	1,067,572	1,067,572		
	8a Oil Spill Cleanup/Response Equipment-O&M	15,150	25,150	15,150	15,150	15,150	15,150	100,900	241,800			241,800
	13 RCRA Corrective Action-O&M	4,167	4,167	4,167	4,167	4,167	4,163	24,998	50,000	50,000		
	14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	124,900	124,900		
	17a Disposal of Noncontainerized Liquid Waste-O&M	18,000	18,000	18,000	48,000	18,000	18,000	138,000	323,000			323,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	223,524	223,524	226,274	226,274	226,274	226,274	1,352,144	2,693,288		2,693,288	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	59,809	59,809	62,559	62,559	62,559	62,563	369,858	728,712	672,657		56,055
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
	20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
	NA Amortization of Gains on Sales of Emissions Allowances	(89,611)	(89,611)	(89,611)	(89,611)	(89,611)	(89,611)	(537,667)	(983,208)			(983,208)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
	22 Pipeline Integrity Management	0	0	0	0	0	0	0	40,000	40,000		
	23 SPCC - Spill Prevention, Control & Countermeasures	37,500	37,500	47,500	37,500	37,500	47,500	245,000	688,000	688,000		
	24 Manatee Rebum	41,667	41,667	41,667	41,667	41,667	41,663	249,998	500,000			500,000
	25 Pt. Everglades ESP Technology	189,693	189,693	189,693	189,693	189,693	189,690	1,138,155	2,276,313			2,276,313
	26 UST Replacement/Removal	0	0	0	0	0	0	0	0	0		
	27 Lowest Quality Water Source	21,539	21,539	21,539	21,539	21,539	21,542	129,237	258,471	258,471		
	28 CWA 316(b) Phase II Rule	43,917	43,917	123,917	43,917	43,917	43,913	343,498	607,000	607,000		
	29 SCR Consumables	29,166	29,166	29,166	29,166	29,166	29,174	175,004	350,000			350,000
	30 HBMP	3,333	3,333	3,333	3,333	3,333	3,337	20,002	40,000	40,000		
	31 CAIR Compliance	76,334	248,334	80,334	101,334	103,334	274,338	884,008	1,611,396			1,611,396
	32 BART	0	0	0	0	0	0	0	0			0
	34 St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0	1,800,000	1,800,000		
	35 Martin Plant Drinking Water System Compliance	0	10,000	7,000	0	0	0	17,000	17,000	17,000		
	36 Low-Level Radioactive Waste Storage	83,333	83,333	83,333	83,333	83,333	83,333	500,000	1,000,000	710,000		290,000
	37 DeSoto Next Generation Solar Energy Center	0	31,165	62,330	93,495	124,660	155,825	467,475	467,475	467,475		
	38 Space Coast Next Generation Solar Energy Center	3,333	3,333	3,333	3,333	3,333	3,333	20,000	20,000	20,000		
	39 Martin Next Generation Solar Energy Center	0	0	0	0	0	0	0	0	0		
	40 Greenhouse Gas Reduction Program	5,000	5,000	5,000	5,000	0	0	20,000	50,000			50,000
2	Total of O&M Activities	$1,173,746	$1,142,118	$1,095,783	$1,362,948	$1,115,113	$1,283,286	$7,172,991	$16,369,481	$ 6,304,506	$ 2,413,172	$7,651,803
3	Recoverable Costs Allocated to Energy	$ 636,448	$ 694,155	$ 516,366	$ 633,366	$ 578,366	$ 705,371	$3,764,072	$ 7,651,803			
4a	Recoverable Costs Allocated to CP Demand	$ 337,117	$ 247,782	$ 376,485	$ 526,650	$ 333,815	$ 374,983	$2,196,833	$ 6,304,506			
4b	Recoverable Costs Allocated to GCP Demand	$ 200,181	$ 200,181	$ 202,931	$ 202,931	$ 202,931	$ 202,931	$1,212,086	$ 2,413,172			
5	Retail Energy Jurisdictional Factor	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%					
6a	Retail CP Demand Jurisdictional Factor	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 628,127	$ 685,079	$ 509,615	$ 625,086	$ 570,805	$ 696,150	$3,714,862	$ 7,551,764			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 332,961	$ 244,727	$ 371,844	$ 520,158	$ 329,700	$ 370,361	$2,169,751	$ 6,226,789			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 200,181	$ 200,181	$ 202,931	$ 202,931	$ 202,931	$ 202,931	$1,212,086	$ 2,413,172			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,161,269	$1,129,987	$1,084,390	$1,348,175	$1,103,436	$1,269,442	$7,096,699	$16,191,725			

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2009 - December 2009

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Projected JAN	Projected FEB	Projected MAR	Projected APR	Projected MAY	Projected JUN	6-Month Sub-Total
1	Description of Investment Projects (A)							
2	Low NOx Burner Technology-Capital	$ 67,941	$ 67,527	$ 67,113	$ 66,699	$ 66,285	$ 65,871	$ 401,436
3b	Continuous Emission Monitoring Systems-Capital	87,218	86,902	86,586	86,271	85,955	85,640	518,572
4b	Clean Closure Equivalency-Capital	313	312	311	310	309	308	1,865
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	139,659	139,251	138,843	138,435	138,027	137,619	831,834
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	128	128	127	127	127	127	764
8b	Oil Spill Cleanup/Response Equipment-Capital	8,580	8,528	9,067	9,603	9,545	9,486	54,810
10	Relocate Storm Water Runoff-Capital	788	787	786	785	783	782	4,711
NA	SO2 Allowances-Negative Return on Investment	(21,474)	(21,523)	(21,351)	(21,179)	(23,954)	(26,562)	(136,044)
12	Scherer Discharge Pipeline-Capital	5,165	5,154	5,144	5,133	5,122	5,112	30,830
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	19,861	19,827	19,794	19,760	19,726	19,692	118,660
21	St. Lucie Turtle Net	11,488	11,483	11,478	11,472	11,467	11,462	68,850
22	Pipeline Integrity Management	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	212,234	211,855	211,477	211,098	210,719	210,340	1,267,723
24	Manatee Reburn	390,300	389,184	388,067	386,951	385,834	384,718	2,325,055
25	Pt. Everglades ESP Technology	948,551	945,951	943,555	941,159	939,061	936,961	5,655,238
26	UST Removal / Replacement	5,514	5,503	5,493	5,483	5,473	5,462	32,929
31	CAIR Compliance	1,363,600	1,421,137	1,505,804	1,612,566	1,743,784	1,888,732	9,535,623
33	CAMR Compliance	378,086	387,711	406,859	425,682	443,772	458,084	2,500,194
34	St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0
35	Martin Plant Drinking Water System Compliance	2,333	2,330	2,327	2,324	2,321	2,318	13,952
36	Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
37	DeSoto Next Generation Solar Energy Center	75,808	132,224	207,099	307,826	439,792	586,551	1,749,300
38	Space Coast Next Generation Solar Energy Center	14,325	21,046	34,493	54,335	69,785	84,511	278,495
39	Martin Next Generation Solar Energy Center	201,848	259,903	321,065	426,937	598,031	797,267	2,605,051
2	Total Investment Projects - Recoverable Costs	3,912,266	4,095,220	4,344,137	4,691,778	5,151,966	5,664,481	27,859,848
3	Recoverable Costs Allocated to Energy	$ 1,660,208	$ 1,670,131	$ 1,685,522	$ 1,708,507	$ 1,737,703	$ 1,771,077	$ 10,233,148
4	Recoverable Costs Allocated to Demand	$ 2,252,058	$ 2,425,090	$ 2,658,615	$ 2,983,271	$ 3,414,263	$ 3,893,404	$ 17,626,701
5	Retail Energy Jurisdictional Factor	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	
6	Retail Demand Jurisdictional Factor	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,638,502	$ 1,648,296	$ 1,663,486	$ 1,686,170	$ 1,714,985	$ 1,747,923	$ 10,099,362
8	Jurisdictional Demand Recoverable Costs (C)	$ 2,224,297	$ 2,395,196	$ 2,625,842	$ 2,946,496	$ 3,372,175	$ 3,845,410	$ 17,409,416
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 3,862,799	$ 4,043,492	$ 4,289,328	$ 4,632,666	$ 5,087,160	$ 5,593,333	$ 27,508,778

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2009 - December 2009

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Projected JUL	Projected AUG	Projected SEP	Projected OCT	Projected NOV	Projected DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)										
2	Low NOx Burner Technology-Capital	$ 65,458	$ 65,044	$ 64,630	$ 64,216	$ 63,802	$ 63,388	$ 386,537	$787,974		$ 787,974
3b	Continuous Emission Monitoring Systems-Capital	85,324	85,008	84,693	84,377	84,061	83,908	507,371	$1,025,943		1,025,943
4b	Clean Closure Equivalency-Capital	307	306	305	304	303	302	1,828	$3,692	3,408	284
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	137,211	136,802	136,394	135,986	135,578	135,170	817,142	$1,648,976	1,522,132	126,844
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	126	126	126	125	125	125	754	$1,517	1,401	116
8b	Oil Spill Cleanup/Response Equipment-Capital	9,397	9,307	9,167	9,028	8,972	10,815	56,685	$111,495	102,919	8,576
10	Relocate Storm Water Runoff-Capital	781	779	778	777	776	774	4,666	$9,377	8,656	721
NA	SO2 Allowances-Negative Return on Investment	(25,896)	(25,067)	(24,238)	(23,409)	(22,581)	(21,752)	(142,943)	($278,987)		(278,987)
12	Scherer Discharge Pipeline-Capital	5,101	5,091	5,080	5,070	5,059	5,049	30,451	$61,280	56,566	4,714
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	$0	0	0
20	Wastewater Discharge Elimination &Reuse	19,659	19,625	19,591	19,557	19,524	19,490	117,446	$236,106	217,944	18,162
21	St. Lucie Turtle Net	11,457	11,452	11,447	11,442	11,437	11,828	69,064	$137,914	127,306	10,608
22	Pipeline Integrity Management	0	0	0	0	0	6,395	6,395	$6,395	5,903	492
23	SPCC - Spill Prevention, Control & Countermeasures	209,961	209,581	209,202	208,822	208,442	211,358	1,257,367	$2,525,090	2,330,852	194,238
24	Manatee Reburn	383,602	382,485	381,369	380,252	379,136	378,019	2,284,862	$4,609,917		4,609,917
25	Pt. Everglades ESP Technology	936,716	936,464	933,846	931,831	929,815	927,193	5,595,864	$11,251,101		11,251,101
26	UST Removal / Replacement	5,452	5,442	5,432	5,421	5,411	5,401	32,559	$65,488	60,450	5,038
31	CAIR Compliance	1,997,471	2,091,915	2,199,053	2,298,745	2,386,652	2,594,077	13,567,914	$23,103,538	21,326,343	1,777,195
33	CAMR Compliance	479,047	511,647	541,419	566,828	603,485	731,402	3,433,827	$5,934,022	5,477,558	456,464
34	St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	19,518	19,518	$19,518	18,016	1,502
35	Martin Plant Drinking Water System Compliance	2,315	2,312	2,310	2,307	2,304	2,301	13,848	$27,801	25,662	2,139
36	Low-Level Radioactive Waste Storage	0	0	0	0	0	27,338	27,338	$27,338	25,235	2,103
37	DeSoto Next Generation Solar Energy Center	751,431	1,157,852	1,633,839	1,885,098	2,005,444	2,041,381	9,475,044	$11,224,344	10,360,933	863,411
38	Space Coast Next Generation Solar Energy Center	99,370	158,412	218,380	234,728	251,027	267,710	1,229,628	$1,508,123	1,392,114	116,009
39	Martin Next Generation Solar Energy Center	1,008,243	1,223,649	1,434,717	1,647,506	1,844,985	2,024,698	9,183,798	$11,788,849	10,882,015	906,834
2	Total Investment Projects - Recoverable Costs	6,182,531	6,988,234	7,867,540	8,469,013	8,923,757	9,545,889	47,976,963	75,836,811	53,945,413	21,891,398
3	Recoverable Costs Allocated to Energy	$1,809,613	$1,870,418	$1,934,702	$1,978,170	$2,010,350	$2,054,998	$11,658,252	$21,891,398		
4	Recoverable Costs Allocated to Demand	$4,372,919	$5,117,816	$5,932,838	$6,490,842	$6,913,406	$7,490,891	$36,318,711	$53,945,413		
5	Retail Energy Jurisdictional Factor	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%				
6	Retail Demand Jurisdictional Factor	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%				
7	Jurisdictional Energy Recoverable Costs (B)	$1,785,954	$1,845,965	$1,909,408	$1,952,308	$1,984,067	$2,028,131	$11,505,833	$21,605,195		
8	Jurisdictional Demand Recoverable Costs (C)	$4,319,013	$5,054,728	$5,859,703	$6,410,829	$6,828,184	$7,398,550	$35,871,007	$53,280,423		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$6,104,967	$6,900,693	$7,769,111	$8,363,137	$8,812,251	$9,426,681	$47,376,840	$74,885,618		

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

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	n/a
3.	Less: Accumulated Depreciation (C)	$14,932,069	14,976,819	15,021,569	15,066,319	15,111,069	15,155,820	15,200,570	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,529,982	$2,485,232	$2,440,482	$2,395,731	$2,350,981	$2,306,231	$2,261,481	n/a
6.	Average Net Investment		2,507,607	2,462,857	2,418,107	2,373,356	2,328,606	2,283,856	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		19,269	18,925	18,581	18,237	17,893	17,550	$110,455
	b. Debt Component (Line 6 x 1.8767% x 1/12)		3,922	3,852	3,782	3,712	3,642	3,572	$22,480
8.	Investment Expenses								
	a. Depreciation (E)		44,750	44,750	44,750	44,750	44,750	44,750	$268,501
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$67,941	$67,527	$67,113	$66,699	$66,285	$65,871	$401,436

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	n/a
3.	Less: Accumulated Depreciation (C)	$15,200,570	15,245,320	15,290,070	15,334,820	15,379,570	15,424,320	15,469,071	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,261,481	$2,216,731	$2,171,981	$2,127,231	$2,082,480	$2,037,730	$1,992,980	n/a
6.	Average Net Investment		2,239,106	2,194,356	2,149,606	2,104,856	2,060,105	2,015,355	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		17,206	16,862	16,518	16,174	15,830	15,486	$208,531
	b. Debt Component (Line 6 x 1.8767% x 1/12)		3,502	3,432	3,362	3,292	3,222	3,152	$42,441
8.	Investment Expenses								
	a. Depreciation (E)		44,750	44,750	44,750	44,750	44,750	44,750	$537,002
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$65,458	$65,044	$64,630	$64,216	$63,802	$63,388	$787,974

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,440,827	12,440,827	12,440,827	12,440,827	12,440,827	12,440,827	12,440,827	n/a
3.	Less: Accumulated Depreciation (C)	$6,683,345	6,717,475	6,751,605	6,785,735	6,819,864	6,853,994	6,888,124	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,757,482	$5,723,352	$5,689,222	$5,655,092	$5,620,962	$5,586,832	$5,552,702	n/a
6.	Average Net Investment		5,740,417	5,706,287	5,672,157	5,638,027	5,603,897	5,569,767	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		44,110	43,848	43,586	43,324	43,061	42,799	$260,728
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,977	8,924	8,871	8,817	8,764	8,711	$53,064
8.	Investment Expenses								
	a. Depreciation (E)		34,130	34,130	34,130	34,130	34,130	34,130	$204,780
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$87,218	$86,902	$86,586	$86,271	$85,955	$85,640	$518,572

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$25,000	$25,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,440,827	12,440,827	12,440,827	12,440,827	12,440,827	12,440,827	12,465,827	n/a
3.	Less: Accumulated Depreciation (C)	$6,888,124	6,922,254	6,956,384	6,990,514	7,024,644	7,058,774	7,092,951	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,552,702	$5,518,572	$5,484,442	$5,450,312	$5,416,183	$5,382,053	$5,372,875	n/a
6.	Average Net Investment		5,535,637	5,501,507	5,467,377	5,433,247	5,399,118	5,377,464	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,537	42,275	42,012	41,750	41,488	41,321	$512,111
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,657	8,604	8,550	8,497	8,444	8,410	$104,226
8.	Investment Expenses								
	a. Depreciation (E)		34,130	34,130	34,130	34,130	34,130	34,177	$409,606
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,324	$85,008	$84,693	$84,377	$84,061	$83,908	$1,025,943

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	36,910	37,021	37,132	37,243	37,354	37,464	37,575	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$21,955	$21,845	$21,734	$21,623	$21,512	$21,401	$21,291	n/a
6.	Average Net Investment		21,900	21,789	21,678	21,568	21,457	21,346	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		168	167	167	166	165	164	$997
	b. Debt Component (Line 6 x 1.8767% x 1/12)		34	34	34	34	34	33	$203
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	$665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$313	$312	$311	$310	$309	$308	$1,865

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	$37,575	37,686	37,797	37,908	38,018	38,129	38,240	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$21,291	$21,180	$21,069	$20,958	$20,847	$20,737	$20,626	n/a
6.	Average Net Investment		21,235	21,124	21,014	20,903	20,792	20,681	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		163	162	161	161	160	159	$1,963
	b. Debt Component (Line 6 x 1.8767% x 1/12)		33	33	33	33	33	32	$400
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	$1,330
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$307	$306	$305	$304	$303	$302	$3,692

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,610,217	13,610,217	13,610,217	13,610,217	13,610,217	13,610,217	13,610,217	n/a
3.	Less: Accumulated Depreciation (C)	$3,258,649	3,302,781	3,346,912	3,391,044	3,435,175	3,479,307	3,523,438	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,351,568	$10,307,437	$10,263,305	$10,219,174	$10,175,042	$10,130,911	$10,086,779	n/a
6.	Average Net Investment		10,329,502	10,285,371	10,241,239	10,197,108	10,152,977	10,108,845	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		79,374	79,035	78,695	78,356	78,017	77,678	$471,155
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16,154	16,085	16,016	15,947	15,878	15,809	$95,891
8.	Investment Expenses								
	a. Depreciation (E)		44,131	44,131	44,131	44,131	44,131	44,131	$264,789
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$139,659	$139,251	$138,843	$138,435	$138,027	$137,619	$831,834

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,610,217	13,610,217	13,610,217	13,610,217	13,610,217	13,610,217	13,610,217	n/a
3.	Less: Accumulated Depreciation (C)	$3,523,438	3,567,570	3,611,701	3,655,833	3,699,964	3,744,095	3,788,227	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,086,779	$10,042,648	$9,998,516	$9,954,385	$9,910,253	$9,866,122	$9,821,991	n/a
6.	Average Net Investment		10,064,714	10,020,582	9,976,451	9,932,319	9,888,188	9,844,056	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		77,339	77,000	76,661	76,322	75,982	75,643	$930,102
	b. Debt Component (Line 6 x 1.8767% x 1/12)		15,740	15,671	15,602	15,533	15,464	15,395	$189,297
8.	Investment Expenses								
	a. Depreciation (E)		44,131	44,131	44,131	44,131	44,131	44,131	$529,578
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$137,211	$136,802	$136,394	$135,986	$135,578	$135,170	$1,648,976

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$20,526	20,557	20,588	20,619	20,650	20,682	20,713	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,504	$10,473	$10,442	$10,411	$10,380	$10,349	$10,317	n/a
6.	Average Net Investment		10,488	10,457	10,426	10,395	10,364	10,333	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		81	80	80	80	80	79	$480
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16	16	16	16	16	16	$98
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	$186
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$128	$128	$127	$127	$127	$127	$764

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$20,713	20,744	20,775	20,806	20,837	20,868	20,899	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,317	$10,286	$10,255	$10,224	$10,193	$10,162	$10,131	n/a
6.	Average Net Investment		10,302	10,271	10,240	10,209	10,178	10,147	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		79	79	79	78	78	78	$951
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16	16	16	16	16	16	$194
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	$372
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$126	$126	$126	$125	$125	$125	$1,517

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$56,000	$0	$0	$0	$56,000
	c. Retirements		($53,550)	$0	$0	$0	$0	$0	($53,550)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$536,885	483,335	483,335	539,335	539,335	539,335	539,335	n/a
3.	Less: Accumulated Depreciation (C)	$214,164	166,236	171,858	177,813	184,102	190,391	196,679	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$322,720	$317,098	$311,476	$361,521	$355,233	$348,944	$342,656	n/a
6.	Average Net Investment		319,909	314,287	336,499	358,377	352,088	345,800	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,458	2,415	2,586	2,754	2,706	2,657	$15,576
	b. Debt Component (Line 6 x 1.8767% x 1/12)		500	492	526	560	551	541	$3,170
8.	Investment Expenses								
	a. Depreciation (E)		5,622	5,622	5,955	6,289	6,289	6,289	$36,065
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,580	$8,528	$9,067	$9,603	$9,545	$9,486	$54,810

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$147,000	$203,000
	c. Retirements		$0	($5,368)	$0	($13,357)	$0	$0	($72,276)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$539,335	539,335	533,966	533,966	520,609	520,609	667,609	n/a
3.	Less: Accumulated Depreciation (C)	$196,679	202,936	203,792	209,934	202,636	208,695	215,979	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$342,656	$336,399	$330,175	$324,033	$317,973	$311,914	$451,630	n/a
6.	Average Net Investment		339,527	333,287	327,104	321,003	314,944	381,772	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,609	2,561	2,514	2,467	2,420	2,934	$31,079
	b. Debt Component (Line 6 x 1.8767% x 1/12)		531	521	512	502	493	597	$6,325
8.	Investment Expenses								
	a. Depreciation (E)		6,257	6,225	6,142	6,059	6,059	7,284	$74,090
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$9,397	$9,307	$9,167	$9,028	$8,972	$10,815	$111,495

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$47,336	47,474	47,611	47,749	47,886	48,024	48,161	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$70,457	$70,320	$70,183	$70,045	$69,908	$69,770	$69,633	n/a
6.	Average Net Investment		70,389	70,251	70,114	69,976	69,839	69,702	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		541	540	539	538	537	536	$3,229
	b. Debt Component (Line 6 x 1.8767% x 1/12)		110	110	110	109	109	109	$657
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	$825
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$788	$787	$786	$785	$783	$782	$4,711

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$48,161	48,298	48,436	48,573	48,711	48,848	48,986	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$69,633	$69,495	$69,358	$69,221	$69,083	$68,946	$68,808	n/a
6.	Average Net Investment		69,564	69,427	69,289	69,152	69,014	68,877	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		535	533	532	531	530	529	$6,421
	b. Debt Component (Line 6 x 1.8767% x 1/12)		109	109	108	108	108	108	$1,307
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	$1,649
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$781	$779	$778	$777	$776	$774	$9,377

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$428,372	429,510	430,649	431,788	432,927	434,065	435,204	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$435,889	$434,750	$433,611	$432,473	$431,334	$430,195	$429,056	n/a
6.	Average Net Investment		435,319	434,181	433,042	431,903	430,764	429,626	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,345	3,336	3,328	3,319	3,310	3,301	$19,939
	b. Debt Component (Line 6 x 1.8767% x 1/12)		681	679	677	675	674	672	$4,058
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	$6,833
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,165	$5,154	$5,144	$5,133	$5,122	$5,112	$30,830

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$435,204	436,343	437,482	438,620	439,759	440,898	442,037	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$429,056	$427,918	$426,779	$425,640	$424,501	$423,363	$422,224	n/a
6.	Average Net Investment		428,487	427,348	426,209	425,071	423,932	422,793	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,293	3,284	3,275	3,266	3,258	3,249	$39,563
	b. Debt Component (Line 6 x 1.8767% x 1/12)		670	668	667	665	663	661	$8,052
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	$13,665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,101	$5,091	$5,080	$5,070	$5,059	$5,049	$61,280

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		-	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		-	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	$606,781	610,430	614,079	617,727	621,376	625,025	628,673	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,754,881	$1,751,232	$1,747,583	$1,743,935	$1,740,286	$1,736,637	$1,732,988	n/a
6.	Average Net Investment		1,753,056	1,749,408	1,745,759	1,742,110	1,738,461	1,734,813	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,471	13,443	13,415	13,387	13,359	13,331	$80,404
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,742	2,736	2,730	2,724	2,719	2,713	$16,364
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	$21,892
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$19,861	$19,827	$19,794	$19,760	$19,726	$19,692	$118,660

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	$628,673	632,322	635,971	639,620	643,268	646,917	650,566	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,732,988	$1,729,340	$1,725,691	$1,722,042	$1,718,393	$1,714,745	$1,711,096	n/a
6.	Average Net Investment		1,731,164	1,727,515	1,723,867	1,720,218	1,716,569	1,712,920	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,303	13,275	13,246	13,218	13,190	13,162	$159,799
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,707	2,702	2,696	2,690	2,685	2,679	$32,523
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	$43,785
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$19,659	$19,625	$19,591	$19,557	$19,524	$19,490	$236,106

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$468,938	468,938	468,938	468,938	468,938	468,938	468,938	n/a
3.	Less: Accumulated Depreciation (C)	($714,347)	(713,800)	(713,253)	(712,706)	(712,159)	(711,612)	(711,065)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,183,285	$1,182,738	$1,182,191	$1,181,644	$1,181,097	$1,180,550	$1,180,003	n/a
6.	Average Net Investment		1,183,012	1,182,465	1,181,918	1,181,371	1,180,823	1,180,276	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		9,090	9,086	9,082	9,078	9,074	9,069	$54,480
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,850	1,849	1,848	1,848	1,847	1,846	$11,088
8.	Investment Expenses								
	a. Depreciation (E)		547	547	547	547	547	547	$3,283
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,488	$11,483	$11,478	$11,472	$11,467	$11,462	$68,850

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$76,149	$76,149
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$468,938	468,938	468,938	468,938	468,938	468,938	545,087	n/a
3.	Less: Accumulated Depreciation (C)	($711,065)	(710,518)	(709,971)	(709,423)	(708,876)	(708,329)	(707,738)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,180,003	$1,179,456	$1,178,909	$1,178,362	$1,177,814	$1,177,267	$1,252,825	n/a
6.	Average Net Investment		1,179,729	1,179,182	1,178,635	1,178,088	1,177,541	1,215,046	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		9,065	9,061	9,057	9,053	9,048	9,337	$109,100
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,845	1,844	1,843	1,842	1,842	1,900	$22,204
8.	Investment Expenses								
	a. Depreciation (E)		547	547	547	547	547	592	$6,610
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,457	$11,452	$11,447	$11,442	$11,437	$11,828	$137,914

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		-	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$1,200,000	$1,200,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	1,200,000	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	850	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$1,199,150	n/a
6.	Average Net Investment		-	0	0	0	0	599,575	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	4,607	$4,607
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	938	$938
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	850	$850
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$6,395	$6,395

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$8,333	$8,333	$8,333	$8,333	$8,333	$8,333	$49,998
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	19,503,628	19,511,961	19,520,294	19,528,627	19,536,960	19,545,293	19,553,626	n/a
3.	Less: Accumulated Depreciation (C)	2,066,853	2,118,028	2,169,221	2,220,433	2,271,662	2,322,908	2,374,173	n/a
4.	CWIP - Non Interest Bearing	-	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$17,436,775	$17,393,932	$17,351,072	$17,308,194	$17,265,298	$17,222,384	$17,179,452	n/a
6.	Average Net Investment		17,415,354	17,372,502	17,329,633	17,286,746	17,243,841	17,200,918	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		133,822	133,493	133,164	132,834	132,505	132,175	$797,993
	b. Debt Component (Line 6 x 1.8767% x 1/12)		27,236	27,169	27,102	27,035	26,968	26,901	$162,409
8.	Investment Expenses								
	a. Depreciation (E)		51,175	51,193	51,211	51,229	51,247	51,265	$307,320
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$212,234	$211,855	$211,477	$211,098	$210,719	$210,340	$1,267,723

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$8,333	$8,333	$8,333	$8,333	$8,333	$626,879	$718,542
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$19,553,626	19,561,959	19,570,292	19,578,625	19,586,958	19,595,291	20,222,170	n/a
3.	Less: Accumulated Depreciation (C)	$2,374,173	2,425,456	2,476,756	2,528,075	2,579,411	2,630,765	2,682,575	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$17,179,452	$17,136,503	$17,093,535	$17,050,550	$17,007,546	$16,964,525	$17,539,594	n/a
6.	Average Net Investment		17,157,978	17,115,019	17,072,042	17,029,048	16,986,036	17,252,060	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		131,845	131,515	131,184	130,854	130,524	132,568	$1,586,482
	b. Debt Component (Line 6 x 1.8767% x 1/12)		26,833	26,766	26,699	26,632	26,564	26,980	$322,885
8.	Investment Expenses								
	a. Depreciation (E)		51,283	51,301	51,318	51,336	51,354	51,810	$615,723
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$209,961	$209,581	$209,202	$208,822	$208,442	$211,358	$2,525,090

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	n/a
3.	Less: Accumulated Depreciation (C)	$3,652,607	3,773,330	3,894,053	4,014,776	4,135,498	4,256,221	4,376,944	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$29,209,961	$29,089,238	$28,968,515	$28,847,793	$28,727,070	$28,606,347	$28,485,624	n/a
6.	Average Net Investment		29,149,600	29,028,877	28,908,154	28,787,431	28,666,708	28,545,986	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		223,990	223,063	222,135	221,207	220,280	219,352	$1,330,028
	b. Debt Component (Line 6 x 1.8767% x 1/12)		45,587	45,398	45,209	45,021	44,832	44,643	$270,690
8.	Investment Expenses								
	a. Depreciation (E)		120,723	120,723	120,723	120,723	120,723	120,723	$724,337
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$390,300	$389,184	$388,067	$386,951	$385,834	$384,718	$2,325,055

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Rebum (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	n/a
3.	Less: Accumulated Depreciation (C)	$4,376,944	4,497,667	4,618,389	4,739,112	4,859,835	4,980,558	5,101,281	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$28,485,624	$28,364,902	$28,244,179	$28,123,456	$28,002,733	$27,882,011	$27,761,288	n/a
6.	Average Net Investment		28,425,263	28,304,540	28,183,817	28,063,095	27,942,372	27,821,649	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		218,424	217,497	216,569	215,642	214,714	213,786	$2,626,660
	b. Debt Component (Line 6 x 1.8767% x 1/12)		44,454	44,265	44,077	43,888	43,699	43,510	$534,584
8.	Investment Expenses								
	a. Depreciation (E)		120,723	120,723	120,723	120,723	120,723	120,723	$1,448,673
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$383,602	$382,485	$381,369	$380,252	$379,136	$378,019	$4,609,917

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$36,000	$0	$80,000	$0	$116,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$81,439,708	81,439,708	81,439,708	81,475,708	81,475,708	81,555,708	81,555,708	n/a
3.	Less: Accumulated Depreciation (C)	$9,139,236	9,420,447	9,701,659	9,982,910	10,264,200	10,545,623	10,827,180	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$72,300,472	$72,019,260	$71,738,049	$71,492,798	$71,211,508	$71,010,085	$70,728,528	n/a
6.	Average Net Investment		72,159,866	71,878,655	71,615,423	71,352,153	71,110,796	70,869,306	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		554,488.51	552,328	550,305	548,282	546,427	544,572	$3,296,402
	b. Debt Component (Line 6 x 1.8767% x 1/12)		112,851	112,411	111,999	111,588	111,210	110,833	$670,892
8.	Investment Expenses								
	a. Depreciation (E)		281,212	281,212	281,251	281,290	281,423	281,557	$1,687,944
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$948,551	$945,951	$943,555	$941,159	$939,061	$936,961	$5,655,238

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$350,000	$0	$0	$84,284	$0	$0	$550,284
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$81,555,708	81,905,708	81,905,708	81,905,708	81,989,992	81,989,992	81,989,992	n/a
3.	Less: Accumulated Depreciation (C)	$10,827,180	11,109,480	11,392,524	11,675,568	11,958,826	12,242,299	12,525,771	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$70,728,528	$70,796,228	$70,513,184	$70,230,140	$70,031,166	$69,747,693	$69,464,221	n/a
6.	Average Net Investment		70,762,378	70,654,706	70,371,662	70,130,653	69,889,429	69,605,957	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		543,750	542,923	540,748	538,896	537,042	534,864	$6,534,624
	b. Debt Component (Line 6 x 1.8767% x 1/12)		110,665	110,497	110,054	109,677	109,300	108,857	$1,329,942
8.	Investment Expenses								
	a. Depreciation (E)		282,300	283,044	283,044	283,258	283,472	283,472	$3,386,536
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$936,716	$936,464	$933,846	$931,831	$929,815	$927,193	$11,251,101

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	16,081	17,190	18,299	19,409	20,518	21,627	22,736	n/a
4.	CWIP - Non Interest Bearing	-	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$476,835	$475,726	$474,617	$473,508	$472,399	$471,290	$470,181	n/a
6.	Average Net Investment		476,281	475,171	474,062	472,953	471,844	470,735	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,660	3,651	3,643	3,634	3,626	3,617	$21,831
	b. Debt Component (Line 6 x 1.8767% x 1/12)		745	743	741	740	738	736	$4,443
8.	Investment Expenses								
	a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	$6,654
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,514	$5,503	$5,493	$5,483	$5,473	$5,462	$32,929

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$22,736	23,845	24,954	26,063	27,172	28,281	29,390	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$470,181	$469,072	$467,963	$466,854	$465,744	$464,635	$463,526	n/a
6.	Average Net Investment		469,626	468,517	467,408	466,299	465,190	464,081	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,609	3,600	3,592	3,583	3,575	3,566	$43,355
	b. Debt Component (Line 6 x 1.8767% x 1/12)		734	733	731	729	728	726	$8,824
8.	Investment Expenses								
	a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	$13,309
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,452	$5,442	$5,432	$5,421	$5,411	$5,401	$65,488

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$6,526,827	$6,072,577	$7,864,942	$9,550,464	$14,665,535	$8,125,453	$52,805,798
	b. Clearings to Plant		$0	$0	$22,951,452	$4,559,403	$9,242,148	$18,715,612	$55,468,615
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$47,002,464	47,002,464	47,002,464	69,953,916	74,513,318	83,755,467	102,471,079	n/a
3.	Less: Accumulated Depreciation (C)	$246,124	324,292	402,461	501,668	628,152	775,143	963,245	n/a
4.	CWIP - Non Interest Bearing	$89,013,965	95,540,792	101,613,368	86,526,858	91,517,920	96,941,306	86,351,147	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$135,770,305	$142,218,963	$148,213,372	$155,979,106	$165,403,086	$179,921,630	$187,858,981	n/a
6.	Average Net Investment		138,994,634	145,216,167	152,096,239	160,691,096	172,662,358	183,890,306	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,068,058	1,115,865	1,168,733	1,234,777	1,326,767	1,413,044	$7,327,244
	b. Debt Component (Line 6 x 1.8767% x 1/12)		217,374	227,104	237,863	251,305	270,027	287,586	$1,491,258
8.	Investment Expenses								
	a. Depreciation (E)		78,168	78,168	99,207	126,484	146,991	188,102	$717,121
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,363,600	$1,421,137	$1,505,804	$1,612,566	$1,743,784	$1,888,732	$9,535,623

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$9,974,003	$10,860,952	$12,731,258	$9,252,219	$9,358,720	$32,640,296	$137,823,246
	b. Clearings to Plant		$74,997	$24,179	$16,000	$16,000	$9,113,630	$17,783,004	$82,496,426
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$102,471,079	102,546,076	102,570,255	102,586,255	102,602,255	111,715,885	129,498,890	n/a
3.	Less: Accumulated Depreciation (C)	$963,245	1,178,258	1,393,362	1,608,502	1,823,672	2,042,699	2,276,113	n/a
4.	CWIP - Non Interest Bearing	$86,351,147	96,250,153	107,086,926	119,802,184	129,038,403	129,283,493	144,340,785	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$187,858,981	$197,617,972	$208,263,820	$220,779,937	$229,816,986	$238,956,679	$271,563,561	n/a
6.	Average Net Investment		192,738,476	202,940,896	214,521,878	225,298,461	234,386,833	255,260,120	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,481,035	1,559,432	1,648,422	1,731,231	1,801,068	1,961,462	$17,509,893
	b. Debt Component (Line 6 x 1.8767% x 1/12)		301,424	317,379	335,491	352,344	366,558	399,201	$3,563,655
8.	Investment Expenses								
	a. Depreciation (E)		215,013	215,104	215,141	215,170	219,027	233,414	$2,029,989
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,997,471	$2,091,915	$2,199,053	$2,298,745	$2,386,652	$2,594,077	$23,103,538

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$2,081,588	$2,059,304	$2,011,504	$1,900,669	$1,194,482	$9,247,547
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$40,882,673	40,882,673	42,964,261	45,023,565	47,035,069	48,935,738	50,130,220	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$40,882,673	$40,882,673	$42,964,261	$45,023,565	$47,035,069	$48,935,738	$50,130,220	n/a
6.	Average Net Investment		40,882,673	41,923,467	43,993,913	46,029,317	47,985,404	49,532,979	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		314,149	322,147	338,057	353,697	368,728	380,620	$2,077,397
	b. Debt Component (Line 6 x 1.8767% x 1/12)		63,936	65,564	68,802	71,985	75,044	77,465	$422,797
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$378,086	$387,711	$406,859	$425,682	$443,772	$458,084	$2,500,194

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$3,338,850	$3,711,375	$2,727,046	$2,768,038	$5,159,385	$22,504,216	$49,456,457
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$50,130,220	53,469,070	57,180,445	59,907,491	62,675,529	67,834,914	90,339,130	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$50,130,220	$53,469,070	$57,180,445	$59,907,491	$62,675,529	$67,834,914	$90,339,130	n/a
6.	Average Net Investment		51,799,645	55,324,758	58,543,968	61,291,510	65,255,222	79,087,022	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		398,037	425,125	449,862	470,974	501,432	607,718	$4,930,545
	b. Debt Component (Line 6 x 1.8767% x 1/12)		81,009	86,522	91,557	95,854	102,053	123,684	$1,003,476
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$479,047	$511,647	$541,419	$566,828	$603,485	$731,402	$5,934,022

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: St. Lucie Cooling Water System Inspect & Maintenance (Project No. 34)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		-	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: St. Lucie Cooling Water System Inspect & Maintenance (Project No. 34)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$3,750,000	$3,750,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	3,750,000	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	2,188	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$3,747,813	n/a
6.	Average Net Investment		-	0	0	0	0	1,873,906	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	14,399	$14,399
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	2,931	$2,931
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	2,188	$2,188
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$19,518	$19,518

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$220,000	220,000	220,000	220,000	220,000	220,000	220,000	n/a
3.	Less: Accumulated Depreciation (C)	$1,323	1,634	1,946	2,258	2,569	2,881	3,193	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$218,677	$218,366	$218,054	$217,742	$217,431	$217,119	$216,807	n/a
6.	Average Net Investment		218,521	218,210	217,898	217,586	217,275	216,963	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,679	1,677	1,674	1,672	1,670	1,667	$10,039
	b. Debt Component (Line 6 x 1.8767% x 1/12)		342	341	341	340	340	339	$2,043
8.	Investment Expenses								
	a. Depreciation (E)		312	312	312	312	312	312	$1,870
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,333	$2,330	$2,327	$2,324	$2,321	$2,318	$13,952

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$220,000	220,000	220,000	220,000	220,000	220,000	220,000	n/a
3.	Less: Accumulated Depreciation (C)	$3,193	3,504	3,816	4,128	4,439	4,751	5,063	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$216,807	$216,496	$216,184	$215,872	$215,561	$215,249	$214,937	n/a
6.	Average Net Investment		216,651	216,340	216,028	215,716	215,405	215,093	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,665	1,662	1,660	1,658	1,655	1,653	$19,992
	b. Debt Component (Line 6 x 1.8767% x 1/12)		339	338	338	337	337	336	$4,069
8.	Investment Expenses								
	a. Depreciation (E)		312	312	312	312	312	312	$3,740
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,315	$2,312	$2,310	$2,307	$2,304	$2,301	$27,801

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		-	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$5,288,004	$5,288,004
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	5,288,004	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	2,900	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$5,285,104	n/a
6.	Average Net Investment		-	0	0	0	0	2,642,552	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	20,306	$20,306
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	4,133	$4,133
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	2,900	$2,900
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$27,338	$27,338

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Desoto (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$3,801,571	$8,399,014	$7,793,704	$13,989,560	$14,549,682	$17,188,564	$65,722,095
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$6,296,363	10,097,934	18,496,948	26,290,652	40,280,212	54,829,894	72,018,458	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$6,296,363	$10,097,934	$18,496,948	$26,290,652	$40,280,212	$54,829,894	$72,018,458	n/a
6.	Average Net Investment		8,197,149	14,297,441	22,393,800	33,285,432	47,555,053	63,424,176	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		62,988	109,864	172,078	255,771	365,421	487,362	$1,453,484
	b. Debt Component (Line 6 x 1.8767% x 1/12)		12,820	22,360	35,022	52,055	74,371	99,189	$295,816
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$75,808	$132,224	$207,099	$307,826	$439,792	$586,551	$1,749,300

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Desoto (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$18,468,496	$32,647,623	$0	$0	$0	$0	$116,838,214
	b. Clearings to Plant		$0	$123,134,577	$26,068,352	$16,354,354	$4,358,778	$2,342,527	$172,258,588
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	123,134,577	149,202,929	165,557,283	169,916,061	172,258,588	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	170,849	548,718	985,447	1,450,917	1,925,684	n/a
4.	CWIP - Non Interest Bearing	$72,018,458	90,486,954	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$72,018,458	$90,486,954	$122,963,728	$148,654,211	$164,571,836	$168,465,144	$170,332,904	n/a
6.	Average Net Investment		81,252,706	106,725,341	135,808,970	156,613,024	166,518,490	169,399,024	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		624,359	820,095	1,043,579	1,203,441	1,279,556	1,301,691	$7,726,205
	b. Debt Component (Line 6 x 1.8767% x 1/12)		127,071	166,908	212,392	244,927	260,418	264,923	$1,572,455
8.	Investment Expenses								
	a. Depreciation (E)		0	170,849	377,868	436,730	465,469	474,767	$1,925,684
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$751,431	$1,157,852	$1,633,839	$1,885,098	$2,005,444	$2,041,381	$11,224,344

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Space Coast (Project No. 38)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,073,371	$380,146	$2,527,892	$1,763,238	$1,577,913	$1,606,737	$8,929,297
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$1,012,286	2,085,657	2,465,803	4,993,695	6,756,933	8,334,846	9,941,583	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,012,286	$2,085,657	$2,465,803	$4,993,695	$6,756,933	$8,334,846	$9,941,583	n/a
6.	Average Net Investment		1,548,972	2,275,730	3,729,749	5,875,314	7,545,890	9,138,215	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		11,903	17,487	28,660	45,147	57,984	70,220	$231,400
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,422	3,559	5,833	9,188	11,801	14,291	$47,095
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$14,325	$21,046	$34,493	$54,335	$69,785	$84,511	$278,495

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s). unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Space Coast (Project No. 38)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,606,736	$9,260,637	$1,824,584	$1,746,244	$1,813,844	$1,829,344	$27,010,686
	b. Clearings to Plant		$0	$6,359,026	$0	$0	$0	$0	$6,359,026
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	6,359,026	6,359,026	6,359,026	6,359,026	6,359,026	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	8,832	26,496	44,160	61,824	79,488	n/a
4.	CWIP - Non Interest Bearing	$9,941,583	11,548,319	14,449,930	16,274,514	18,020,758	19,834,602	21,663,946	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,941,583	$11,548,319	$20,800,124	$22,607,044	$24,335,624	$26,131,804	$27,943,484	n/a
6.	Average Net Investment		10,744,951	16,174,222	21,703,584	23,471,334	25,233,714	27,037,644	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		82,566	124,285	166,774	180,358	193,900	207,762	$1,187,045
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16,804	25,295	33,942	36,707	39,463	42,284	$241,590
8.	Investment Expenses								
	a. Depreciation (E)		0	8,832	17,664	17,664	17,664	17,664	$79,488
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$99,370	$158,412	$218,380	$234,728	$251,027	$267,710	$1,508,123

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Martin (Project No. 39)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$8,232,000	$4,323,000	$8,904,000	$13,992,000	$23,009,000	$20,078,000	$78,538,000
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$17,710,000	25,942,000	30,265,000	39,169,000	53,161,000	76,170,000	96,248,000	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$17,710,000	$25,942,000	$30,265,000	$39,169,000	$53,161,000	$76,170,000	$96,248,000	n/a
6.	Average Net Investment		21,826,000	28,103,500	34,717,000	46,165,000	64,665,500	86,209,000	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		167,715	215,952	266,771	354,740	496,901	662,444	$2,164,522
	b. Debt Component (Line 6 x 1.8767% x 1/12)		34,134	43,951	54,294	72,197	101,130	134,822	$440,529
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$201,848	$259,903	$321,065	$426,937	$598,031	$797,267	$2,605,051

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Solar - Martin (Project No. 39)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$25,548,000	$21,036,000	$24,610,000	$21,408,000	$21,299,000	$17,566,000	$210,005,000
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$96,248,000	121,796,000	142,832,000	167,442,000	188,850,000	210,149,000	227,715,000	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$96,248,000	$121,796,000	$142,832,000	$167,442,000	$188,850,000	$210,149,000	$227,715,000	n/a
6.	Average Net Investment		109,022,000	132,314,000	155,137,000	178,146,000	199,499,500	218,932,000	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		837,743	1,016,723	1,192,099	1,368,904	1,532,988	1,682,310	$9,795,289
	b. Debt Component (Line 6 x 1.8767% x 1/12)		170,500	206,926	242,619	278,603	311,997	342,388	$1,993,560
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,008,243	$1,223,649	$1,434,717	$1,647,506	$1,844,985	$2,024,698	$11,788,849

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P pages 51-54
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 51-54
(F) Applicable amortization period(s). See Form 42-4P pages 51-54
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount	
1	Working Capital Dr (Cr)									
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b 158.200 Allowances Withheld	0	0	0	0	0	0	0		
	c 182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
	d 254.900 Other Regulatory Liabilities-Gains	(2,307,251)	(2,336,640)	(2,318,032)	(2,299,424)	(2,280,816)	(2,899,518)	(2,844,918)		
2	Total Working Capital	($2,307,251)	($2,336,640)	($2,318,032)	($2,299,424)	($2,280,816)	($2,899,518)	($2,844,918)		
3	Average Net Working Capital Balance		(2,321,945)	(2,327,336)	(2,308,728)	(2,290,120)	(2,590,167)	(2,872,218)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(17,842)	(17,884)	(17,741)	(17,598)	(19,903)	(22,071)	(113,038)	
	b Debt Component (Line 6 x 1.6698% x 1/12)		(3,631)	(3,640)	(3,611)	(3,582)	(4,051)	(4,492)	(23,006)	
5	Total Return Component		($21,474)	($21,523)	($21,351)	($21,179)	($23,954)	($26,562)	($136,044)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(18,608)	(18,608)	(18,608)	(18,608)	(281,499)	(89,611)	(445,542)	
	b 411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	-	
	c 509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($18,608)	($18,608)	($18,608)	($18,608)	($281,499)	($89,611)	($445,542)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(40,081)	(40,131)	(39,959)	(39,787)	(305,453)	(116,174)		
	a Recoverable Costs Allocated to Energy		(40,081)	(40,131)	(39,959)	(39,787)	(305,453)	(116,174)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%		
10	Demand Jurisdictional Factor		98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%		
11	Retail Energy-Related Recoverable Costs (B)		(39,513)	(39,562)	(39,392)	(39,223)	(301,119)	(114,525)	(573,334)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	-	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($39,513)	($39,562)	($39,392)	($39,223)	($301,119)	($114,525)	($573,334)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.2013% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount	
1	Working Capital Dr (Cr)									
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
	b 158.200 Allowances Withheld	$0	0	0	0	0	0	0		
	c 182.300 Other Regulatory Assets-Losses	$0	0	0	0	0	0	0		
	d 254.900 Other Regulatory Liabilities-Gains	($2,844,918)	(2,755,307)	(2,665,695)	(2,576,084)	(2,486,473)	(2,396,862)	(2,307,251)		
2	Total Working Capital	($2,844,918)	($2,755,307)	($2,665,695)	($2,576,084)	($2,486,473)	($2,396,862)	($2,307,251)		
3	Average Net Working Capital Balance		(2,800,112)	(2,710,501)	(2,620,890)	(2,531,279)	(2,441,668)	(2,352,056)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(21,517)	(20,828)	(20,139)	(19,451)	(18,762)	(18,074)	(231,808)	
	b Debt Component (Line 6 x 1.6698% x 1/12)		(4,379)	(4,239)	(4,099)	(3,959)	(3,819)	(3,678)	(47,178)	
5	Total Return Component		($25,896)	($25,067)	($24,238)	($23,409)	($22,581)	($21,752)	($278,987)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(89,611)	(89,611)	(89,611)	(89,611)	(89,611)	(89,611)	(983,208)	
	b 411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	-	
	c 509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($89,611)	($89,611)	($89,611)	($89,611)	($89,611)	($89,611)	($983,208)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(115,507)	(114,678)	(113,849)	(113,021)	(112,192)	(111,363)		
	a Recoverable Costs Allocated to Energy		(115,507)	(114,678)	(113,849)	(113,021)	(112,192)	(111,363)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%		
10	Demand Jurisdictional Factor		98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%		
11	Retail Energy-Related Recoverable Costs (B)		(113,868)	(113,051)	(112,234)	(111,417)	(110,600)	(109,783)	(1,244,287)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	-	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($113,868)	($113,051)	($112,234)	($111,417)	($110,600)	($109,783)	($1,244,287)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.2013% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
2009 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/08	Estimated Balance 12/31/2009
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	2,689,232.57	2,689,232.57
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	2,416,089.59	2,416,089.59
02 - Low NOX Burner Technology Total					**17,462,050.77**	**17,462,050.77**
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	59,227.10	59,227.10
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.30%	37,385.86	37,385.86
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.40%	407,386.53	408,386.53
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.10%	347,150.58	348,150.58
	02 - Steam Generation Plant	Cutler Comm	31100	0.00%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	0.50%	36,276.52	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	0.20%	310,454.41	310,454.41
	02 - Steam Generation Plant	Cutler U6	31200	1.00%	311,861.95	311,861.95
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	477,896.88	477,896.88
	02 - Steam Generation Plant	Manatee U2	31100	4.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	508,551.98	508,551.98
	02 - Steam Generation Plant	Martin Comm	31200	4.10%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.50%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.80%	531,413.18	533,413.18
	02 - Steam Generation Plant	Martin U2	31100	1.50%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.50%	527,263.77	529,263.77
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.20%	67,787.69	67,787.69
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	458,612.69	458,612.69
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	480,873.50	480,873.50
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	508,210.30	508,210.30
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	517,303.41	517,303.41
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.40%	11,495.25	11,495.25
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	453,591.19	453,591.19
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	437,621.87	437,621.87
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	434,357.43	435,357.43
	02 - Steam Generation Plant	Scherer U4	31200	1.90%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	220,702.83	220,702.83
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	216,142.08	216,142.08
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.30%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31200	2.10%	37,954.50	37,954.50
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	545,683.81	545,683.81
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	504,788.03	504,788.03
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.10%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	5.00%	463,054.20	463,054.20
	05 - Other Generation Plant	FtLauderdale U5	34300	3.70%	474,559.99	474,559.99
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.50%	21,625.54	26,625.54
	05 - Other Generation Plant	Martin U3	34300	5.80%	413,342.64	415,342.64
	05 - Other Generation Plant	Martin U4	34300	5.70%	405,944.43	407,944.43
	05 - Other Generation Plant	Martin U8	34300	5.50%	4,688.46	4,688.46
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	6.30%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.20%	332,065.69	333,065.69
	05 - Other Generation Plant	Putnam U2	34300	5.40%	365,469.22	366,469.22
	05 - Other Generation Plant	Sanford U4	34300	5.60%	98,339.95	101,839.95
	05 - Other Generation Plant	Sanford U5	34300	5.70%	56,521.05	60,021.05
03 - Continuous Emission Monitoring Total					**12,440,826.58**	**12,465,826.58**

Florida Power & Light Company
Environmental Cost Recovery Clause
2009 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/08	Estimated Balance 12/31/2009
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	17,254.20	17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.30%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					**58,865.78**	**58,865.78**
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	1,170,450.32	1,170,450.32
	02 - Steam Generation Plant	Martin U1	31100	1.50%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.30%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	68,893.65	68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					**13,610,217.48**	**13,610,217.48**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31670	7-Year	456,862.61	440,587.11
	02 - Steam Generation Plant	Martin Comm	31600	3.20%	23,107.32	23,107.32
	05 - Other Generation Plant	Amortizable	34650	5-Year	9,271.59	156,271.59
	05 - Other Generation Plant	Amortizable	34670	7-Year	45,699.54	45,699.54
	08 - General Plant	Amortizable	39190	3-Year	1,943.47	1,943.47
08 - Oil Spill Clean-up/Response Equipment Total					**536,884.53**	**667,609.03**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.60%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.00%	689.11	689.11
12 - Scherer Discharge Pipline Total					**864,260.42**	**864,260.42**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.80%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.50%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	560,786.81	560,786.81
20 - Wastewater/Stormwater Discharge Elimination Total					**2,361,661.78**	**2,361,661.78**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	468,938.12	545,087.12
21 - St. Lucie Turtle Nets Total					**468,938.12**	**545,087.12**
22 - Pipeline Integrity						
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	0.00	1,200,000.00
22 - Pipeline Integrity Total					**0.00**	**1,200,000.00**

Florida Power & Light Company
Environmental Cost Recovery Clause
2009 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/08	Estimated Balance 12/31/2009
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	665,907.33	665,907.33
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	13,451.85	13,451.85
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.90%	13,450.30	13,450.30
	02 - Steam Generation Plant	CapeCanaveral U1	31100	2.00%	30,444.00	30,444.00
	02 - Steam Generation Plant	CapeCanaveral U2	31100	1.30%	30,444.00	30,444.00
	02 - Steam Generation Plant	Cutler Comm	31400	0.00%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	711,563.43	711,563.43
	02 - Steam Generation Plant	Manatee Comm	31500	3.70%	5,000.00	5,000.00
	02 - Steam Generation Plant	Manatee U1	31500	3.60%	10,935.00	10,935.00
	02 - Steam Generation Plant	Manatee U2	31500	3.60%	10,935.00	10,935.00
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	45,303.00	45,303.00
	02 - Steam Generation Plant	Martin U1	31100	1.50%	182,507.50	182,507.50
	02 - Steam Generation Plant	Martin U2	31100	1.50%	182,507.50	182,507.50
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	1,985,476.00	1,985,476.00
	02 - Steam Generation Plant	PtEverglades U3	31100	2.60%	32,500.00	32,500.00
	02 - Steam Generation Plant	PtEverglades U4	31100	2.60%	32,500.00	32,500.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	736,958.97	736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	894,298.77	894,298.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	859,887.21	859,887.21
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31500	2.10%	13,559.00	13,559.00
	02 - Steam Generation Plant	Turkey Pt U1	31100	2.50%	12,500.00	12,500.00
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	12,500.00	12,500.00
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	404,549.02	404,549.02
	03 - Nuclear Generation Plant	StLucie U1	32400	1.70%	437,945.38	1,056,487.38
	03 - Nuclear Generation Plant	StLucie U2	32300	1.90%	396,779.37	396,779.37
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	7,065.10
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.80%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.10%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.90%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.50%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	4.80%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.40%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34300	5.50%	74,555.00	74,555.00
	05 - Other Generation Plant	PtEverglades GTs	34100	1.50%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.20%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	2.50%	951,562.91	976,562.91
	06 - Transmission Plant - Electric		35300	2.80%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	2.60%	2,862,093.44	2,937,093.44
	08 - General Plant		39000	2.70%	12,843.35	12,843.35
23 - Spill Prevention Clean-Up & Countermeasures Total					**19,503,627.52**	**20,222,169.52**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	16,771,308.37	16,771,308.37
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	16,091,259.94	16,091,259.94
24 - Manatee Reburn Total					**32,862,568.31**	**32,862,568.31**
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31100	2.60%	298,709.93	307,709.93
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	10,404,603.15	10,492,103.15
	02 - Steam Generation Plant	PtEverglades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	PtEverglades U1	31600	1.00%	307,032.30	307,032.30
	02 - Steam Generation Plant	PtEverglades U2	31100	2.60%	184,084.01	193,084.01
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	11,979,735.29	12,151,519.29
	02 - Steam Generation Plant	PtEverglades U2	31500	2.10%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	PtEverglades U2	31600	1.70%	324,086.94	324,086.94
	02 - Steam Generation Plant	PtEverglades U3	31100	2.60%	4,858,902.04	4,867,902.04
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	16,194,431.96	16,361,931.96
	02 - Steam Generation Plant	PtEverglades U3	31500	2.20%	2,427,316.36	2,427,316.36
	02 - Steam Generation Plant	PtEverglades U4	31100	2.60%	0.00	9,000.00
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	25,123,410.25	25,210,910.25
	02 - Steam Generation Plant	PtEverglades U4	31500	2.10%	2,882,565.18	2,882,565.18
25 - PPE ESP Technology Total					**81,439,707.89**	**81,989,991.89**

Florida Power & Light Company
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2009 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/08	Estimated Balance 12/31/2009
26 - UST Remove/Replace						
	08 - General Plant		39000	2.70%	492,916.42	492,916.42
26 - UST Remove/Replace Total					**492,916.42**	**492,916.42**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee U1	31400	3.70%	275,727.81	275,727.81
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	0.00	19,618,970.10
	02 - Steam Generation Plant	Manatee U2	31400	3.00%	0.00	8,482,193.14
	02 - Steam Generation Plant	Martin U1	31200	1.80%	11,784,716.57	11,784,716.57
	02 - Steam Generation Plant	Martin U1	31400	1.30%	8,864,406.30	8,964,406.30
	02 - Steam Generation Plant	Martin U2	31200	1.50%	0.00	18,516,096.73
	02 - Steam Generation Plant	Martin U2	31400	0.80%	0.00	8,280,537.95
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	4,189.46	27,502,817.42
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	25,797,452.64	25,797,452.64
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.20%	110,241.49	110,241.49
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	57,855.15	57,855.15
	05 - Other Generation Plant	PtEverglades GTs	34300	2.60%	107,874.32	107,874.32
31 - Clean Air Interstate Rule (CAIR) Total					**47,002,463.74**	**129,498,889.62**
34 - St Lucie Cooling Water System Inspect. & Maintenance						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	0.00	3,750,000.00
34 - St Lucie Cooling Water System Inspect. & Maintenance Total					**0.00**	**3,750,000.00**
35 - Martin Drinking Water System						
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	220,000.00	220,000.00
35 - Martin Drinking Water System Total					**220,000.00**	**220,000.00**
36 - Low Level Waste Storage						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	0.00	3,807,997.00
	03 - Nuclear Generation Plant	TurkeyPt Comm	32100	1.10%	0.00	1,480,007.00
36 - Low Level Waste Storage Total					**0.00**	**5,288,004.00**
37 - DeSoto Solar Energy Center						
	05 - Other Generation Plant	DeSoto Solar Energy Center	34300	3.33%	0.00	172,258,588.00
37 - DeSoto Solar Energy Center Total					**0.00**	**172,258,588.00**
38 - Spacecoast Solar Energy Center						
	01 - Intangible Plant	Kennedy Space Center	30300	30-Year	0.00	6,359,026.00
38 - Spacecoast Solar Energy Center Total					**0.00**	**6,359,026.00**
Grand Total					**229,473,813.17**	**502,326,556.55**

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Air Operating Permit Fees - O & M
Project No. 1

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, and Florida Statutes 403.0872, require each major source of air pollution to pay an annual license fee. The amount of the fee is based on each source's previous year's emissions. It is calculated by multiplying the applicable annual operation license fee factor ($25 per ton for both Florida and Georgia) by the tons of each air pollutant emitted by the unit during the previous year and regulated in each unit's air operating permit, up to a total of 4,000 tons per pollutant. The major regulated pollutants at the present time are sulfur dioxide (SO2), nitrogen oxides (NOx) and particulate matter. The fee covers units in FPL's service area, as well as Unit 4 of Plant Scherer located in Juliette, Georgia, within the Georgia Power Company service area. Scherer Unit 4's annual air operating permit fee is approximately $100,000. FPL's share of ownership of that unit is 76.36%. The fees for FPL's units are paid to the Florida Department of Environmental Protection (FDEP) generally in February of each year, whereas FPL pays its share of the fees for Scherer Unit 4 to Georgia Power Company on a monthly basis.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The monthly fees for 2007 emissions at Scherer have been paid and continue to be paid in 2008. 2007 air operating permit fees for the Florida facilities were calculated in January 2008 utilizing 2007 operating information. They were paid to the FDEP in February, 2008.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $324,282 (16.5%) lower than originally projected. This variance is primarily due to higher usage of natural gas as a fuel across the FPL fleet due to the higher costs of residual oil. Permit fees are based on emissions, which are proportionate to the type of fuel used at each Florida facility. Utilizing natural gas in lieu of residual oil significantly reduces SO2, Particulate Matter (PM) and NOx emissions.

Project Progress Summary:
The monthly fees for 2007 emissions at Scherer have been paid and continue to be paid in 2008. 2007 air operating permit fees for the Florida facilities were calculated in January 2008 utilizing 2007 operating information. They were paid to the FDEP in February 2008.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project expenditures for the period January 2009 through December 2009 are expected to be $1,958,100.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring Systems (CEMS) - O & M
Project No. 3a

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO2, NOx, CO, Carbon Dioxide (CO2/O2) emissions, as well as opacity data from affected air pollution sources. FPL has 57 units which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants and opacity. These Systems continuously extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability. Operation and maintenance of these systems in accordance with the provisions of 40 CFR Part 75 is an ongoing activity which follow the Title IV CEMS Quality Assurance Program Manual.

Project Accomplishments:
(January 1, 2008 to June 1, 2008)
Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled. QA/QC maintenance continues to be performed on the analyzers per the requirements of the Title IV CEM Quality Assurance Program Manual. Calibration span gases and CEMS required parts continue to be purchased. In addition, analysis of fuel oil for sulfur content, heat of combustion and carbon continues to be performed per the requirements of 40 CFR Part 75, Appendix D. CEMS 24/7 Software Support contract with General Electric (CEMS NETDAHS) continues to be maintained to ensure integrity of the CEMS Systems and to ensure compliance with EPA and State Agencies. Additionally said software has been upgraded to comply with the new EPA reporting requirements.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $205,903 (27.4%) higher than originally projected. The increased estimate was due largely to the additional cost of the CEMS software upgrade. This upgrade was needed to meet the EPA's mandate of reporting in XML format starting 1/1/2009. Additionally the higher cost of replacement parts for the new model analyzers installed at the end of 2007 and in the first half of 2008 is reflected.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
This is an ongoing project. Each reporting period will include the cost of quality assurance activities, training, spare parts, calibration gas, and software support.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project expenditures for the period January 2009 through December 2009 are expected to be $999,894.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M
Project No. 5a

Project Description:
Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

PMT Tanks 1371/A (with the capacity 500,000 BBLS), TPE Tank 808 (capacity 200,000 BBLS), PFL Light Oil Tank #5 (capacity 80,000 BBLS) and TPE Light oil Tank # 901 are due for API in-service inspections. All inspections except TPE tank 901 were performed by TEAM in April, 2008. No discrepancies were reported and all fuel storage tanks appear to be suitable for continued services. The next due dates for external inspection was determined by API certified inspector after 5 years. TPE Tank 901 is due in July, 2008.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections & API 570 will be completed for this year and all 2008 tank registration fees have been paid.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $836,100 (123.5%) higher than originally projected. The following project activities were identified after the filing of the original estimates for 2008:
1) Turkey Point Unit 1 Metering Tank Roof Replacement and Bottom Plate Projection Repairs project. The cross-tie valve between the two units' metering tanks was not functional and replacement and repairs took longer than expected to complete.
2) External coating of Port Everglades Terminal above grade piping. The scope of this activity was increased due to additional piping and the move from epoxy coating to silicon coating which has a longer life.
3) Performing API 570 inspections on bulk light oil piping at Ft. Lauderdale and Port Everglades power plants.
4) Martin Plant Units 1 &2 Metering Tanks painting.
5) Port Everglades Terminal Tank 805 API out-of- service inspection.
6) Painting of Fort Myers Plant Units 1&2 Tanks. The initial plan was to paint entire roof of tank No.1 and touchup the roof of Tank No. 2. The entire roofs of both tanks were painted.
7) Fort Myers Plant Tank No. 2 visual and settlement survey. Due to a leak discovered on one of the leak detection ports, a visual and settlement survey was implemented on the tank.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
This is an ongoing project. Each reporting period will include ongoing maintenance of above ground fuel storage tanks in accordance with F.A.C. Chapter 62-761. We have replaced the roof of PCC 1& PTF 1 Metering Tanks which were out of compliance due to the holes in the roof and for this purpose we had to evacuate, clean, and gas free the tank in order to be able to perform hot work on the roof of the tank. Decision was made to conduct the API 653 internal inspection and tank strapping at the same time so we don't need to take the tank out of service a few years later, and clean and gas freeing it just because of API internal inspection. Both projects have been successfully completed, PCC on March, and PTF on May, 2008. TPE tank 805 was due for API out-of-service inspection in April, 2008. The tank was taken out from service, evacuated, cleaned and gas freed for this inspection. There are some code required repairs which is in progress.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are expected to be $1,067,572.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil Spill Cleanup/Response Equipment - O&M
Project No. 8a

Project Description:
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Plan updates have continued to be performed and filed for all sites as required. The Corporate Oil Spill Response Plan has been updated to include the new NIMS ICS requirements. Routine maintenance of all oil spill equipment has continued throughout the year as well as the performance of spill management drills including a corporate team drill and deployment drills throughout the system. There has also been training for some new team members. Finally, a boat lift was installed at the Riviera Plant to allow for quicker deployment time. During the third and fourth quarters boat lifts will also be installed at the Turkey Point and Cape Canaveral sites.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance is expected to be $456, or -0.2%.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
This is an ongoing project. Each reporting period will include ongoing maintenance of all oil spill equipment in accordance with OPA 90. Additionally, following a formal assessment of the oil spill program, FPL retained a contractor to perform the mandated OSRO (oil spill removal organization) function. This contractor will also perform maintenance (required) on the oil spill equipment at all of the power plants as well as perform an annual (required) equipment deployment drill at these facilities. We will be installing boat lifts at Cape Canaveral and Turkey Point Plants during the third and fourth quarter.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are expected to be $241,800. In addition to the ongoing operation described in the 2008 summary, FPL has 1) retained a spill management company to assist in corporate-level responses, 2) improved/enhanced the Fleet's ability to mobilize spill equipment (specifically boats), and 3) continue to certify all oil spill response members in the NIMS mandated Incident Command System (ICS).

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: RCRA Corrective Action - O & M
Project No. 13

Project Description:
Under the Hazardous and Solid Waste Amendments of 1984 (amending the Resource Conservation and Recovery Act, or RCRA), the U.S. EPA has the authority to require hazardous waste treatment facilities to investigate whether there have been releases of hazardous waste or constituents from non-regulated units on the facility site. If contamination is found to be present at levels that represent a threat to human health or the environment, the facility operator can be required to undertake "corrective action" to remediate the contamination. In April 1994, the U.S. EPA advised FPL that it intended to initiate RCRA Facility Assessments (RFAs) at FPL's nine former hazardous waste treatment facility sites. The RFA is the first step in the RCRA Corrective Action process. At a minimum, FPL will be responding to the agency's requests for information concerning the operation of these power plants, their waste streams, their former hazardous waste treatment facilities, and their non-regulated Solid Waste Management Units (SWMUs). FPL may also conduct assessments of human health risks resulting from possible releases from the SWMU's in order to demonstrate that any residual contamination does not represent an undue threat to human health or the environment. Other response actions could include a voluntary clean-up or compliance with the agency's imposition of the full gamut of RCRA Corrective Action requirements, including RCRA Facility Investigation, Corrective Measures Study, and Corrective Measures Implementation.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
EPA and the FDEP have agreed that no further action is required at the Fort Myers, Cape Canaveral, and Martin Power Plants. EPA and the FDEP agree that no further action is required at the Putnam Power Plant, except for the petroleum clean-up that is going forward under the FDEP District Office waste clean-up oversight. The EPA withdrew the 2007 order. In January, 2005, FPL entered into a bilateral Agreement with the FDEP to complete the assessments at the Sanford, Manatee, Saint Lucie, and Turkey Point Plants. During 2005, FPL prepared documents for the Sanford Plant that were submitted to the FDEP. In March 2007, a draft Facility Evaluation Report was received and reviewed by FPL. The draft report was returned to FDEP and a final report was received in the second quarter of 2007, awarding No Further Action for the Sanford Power Plant. Document preparation for the Manatee Plant was completed during third quarter 2007 and submitted to FDEP. A Facility Evaluation took place in the third quarter of 2007 and the site received the final report from the Department granting No Further Action. Site preparation activities were completed at Turkey Point Plant during the third & fourth quarter of 2007. A Facility Evaluation took place in the fourth quarter of 2007 and the site received the draft report from the Department granting No Further Action. The final report from the Department for the Turkey Point Plant is expected to be received shortly.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $57,022 (46.7%) lower than originally projected. Estimates were included in 2008 for further action that might be required by FDEP at Turkey Point or Manatee Plant after 2007. However, FPL completed all work associated with RCRA at the Manatee and Turkey Point Fossil sites in 2007. The FDEP has granted final "No Further Action" for the Manatee Plant. The FDEP is finalizing the draft report approved by FPL for the Turkey Point Plant. This draft report recommended No Further Action for the site.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The Power Generation Division completed all work associated with RCRA at the Manatee and Turkey Point Fossil sites in 2007. The FDEP has granted final No Further Action for the Manatee Plant. The FDEP is finalizing the draft report approved by FPL for the Turkey Point Plant. This draft report recommended No Further Action for the site. No additional work was recommended by the Department in order to reach a No Further Action agreement. No other activities are scheduled for 2008. The final report from the Department granting No Further Action for the Turkey Point Plant is expected to be received shortly.

Project Projection:
(January 1, 2009 to December 31, 2009)
Projections for 2009 are $50,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NPDES Permit Fees - O & M
Project No. 14

Project Description:
In compliance with State of Florida Rule 62-4.052, FPL is required to pay annual regulatory program and surveillance fees for any permits it requires to discharge wastewater to surface waters under the National Pollution Discharge Elimination System. These fees effect the Florida legislature's intent that the Florida Department of Environmental Protection's (FDEP) costs for administering the NPDES program be borne by the regulated parties, as applicable. The fees for each permit type are as set forth in the rule, with an effective date of May 1, 1995, for their implementation.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The NPDES permit fees were paid to FDEP for Power Generation Operating Plants.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in project expenditures is estimated to be $30,505 less than (19.7% lower) the original estimate. This reflects inadvertently budgeting the permit renewal application fees as ECRC expenditures. Permit renewal application fees are not classified as ECRC recoverable and thus have been removed from the ECRC true-up calculation.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The NPDES annual regulatory program and surveillance fees were paid to FDEP for Power Generation Operating Plants.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project expenditures for the annual regulatory program and surveillance fees for the period January 2009 through December 2009 are expected to be $124,900. The regulatory program and surveillance fees will be due in January, 2009.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Disposal of Noncontainerized Liquid Waste - O&M
Project 17a

Project Description:
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Ash work is complete at Manatee, and Turkey Point. Port Everglades will be complete in July. Remaining on the schedule for 2008 are Cape Canaveral, Sanford and Martin. Approximately $25,000 will be spent on Maintenance Costs to replace worn hoses, filter cloths and a pump.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $32,803 (11.0%) higher than originally projected. The variance is primarily due to greater than anticipated ash accumulation in the storage basins at the Turkey Point site. As a result of the increase in ash material to be handled for removal, the site incurred extra expenses due to the use of additional moving equipment to support the job. Also, the time associated with the contractor completing the job contributed to the increases in manpower hours.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
This is an ongoing project. The frequency of basin clean out is a function of basin capacity and rate of sludge/ash generation. Typically, FPL generates 5,000 tons (@ 50% solids) of sludge per year.

Project Projections:
(January 1, 2009 to December 31, 2009)
Project fiscal expenditures for the period January 2009 through December 2009 are now estimated at $323,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Substation Pollutant Discharge Prevention & Removal - O&M
Project No. 19a, 19b, 19c

Project Description:
Florida Statute Chapter 376 Pollutant Discharge Prevention and Removal requires that any person discharging a pollutant, defined as any commodity made from oil or gas, shall immediately undertake to contain, remove and abate the discharge to the satisfaction of the department. Florida Statute Chapter 403 holds it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation. Additionally, remediation activities will be conducted in Dade and Broward counties which adhere to county regulations as defined in municipal codes.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
We have repaired leaks and/or regasketed 37 distribution transformers and 6 transmission transformers using 3 vendors. However, obtaining equipment clearances to make the necessary repairs has slowed this work down a bit. It is anticipated that this work will increase toward the end of the year once the cooler weather arrives and equipment clearances can be more easily obtained. In addition, we have also conducted minor oil spill clean-ups as a result of equipment leaks at 31 units. There is no equipment encapsulation work scheduled from this year. However, encapsulation work will continue for the remaining units in 2009. Environmental remediation work continues in Miami-Dade County at 7 substations due to various degrees of lead and arsenic contamination.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be:
- 19a The variance in project expenditures is estimated to be $665,806 or 68.8% higher than projected. Three vendors are being used to conduct equipment leak repairs, as opposed to the previous use of only one vendor; therefore, significantly more repairs are expected to be completed this year.
- 19b The variance in project expenditures is estimated to be $14,110 or 4.0% lower than projected.
- 19c No variance is anticipated.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The equipment leak repair and regasketing work continues. We are in the progress of developing a complex data base to provide greater efficiency in managing this work. We are currently using 3 leak repair vendors to provide faster leak repairs. However, obtaining equipment clearances during the summer peak season has slowed this work down a bit. But it is anticipated that this work will increase during the fall once cooler weather arrives. The arsenic in soils and groundwater is being addressed at 7 substation locations in Miami-Dade County. The closure of 2 of the substations is anticipated in 2009.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are expected to be:
- 19a $2,693,288
- 19b 728,712
- 19c ($560,232)

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater/Stormwater Discharge Elimination & Reuse - O&M
Project No. 20

Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants, and the Dade County DERM requires Turkey Point and Cutler Plant wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The project is on hold due to the Pt. Everglades ESP Project.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The project is on hold due to the Pt. Everglades ESP Project.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are expected to be $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net – O&M
Project No. 21

Project Description:
The Turtle Net project says that FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service ("NMFS"). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. (The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years). Based on the number of captured turtles in 2001, the lethal take limit for loggerhead and green turtles in that year was six (references; Nuclear Regulatory Commission letter dated May 18, 2001 included as Exhibit 1, Document No. 1, Endangered Species Act Section 7 Consultation Biological Opinion Incidental Take Statement dated May 4, 2001 included as Exhibit 1, Document No. 2, Appendix B To Facility Operating License No. NPF-16 St. Lucie Unit 2, Environmental Protection Plan, Non-Radiological, Amendment No. 103 included as Exhibit 1, Document No. 3). In 2001, FPL experienced six lethal takings of loggerhead and green turtles at the St. Lucie Power Plant, indicating that its existing measures to limit such takings were performing marginally.

The existing net is in need of maintenance. To facilitate this work, a temporary net will be situated to allow removal of the existing net. The new net having been properly coated for UV protection and anti-fouling will be installed replacing the existing net. The existing net will be repaired and maintained as a spare to allow rotation of the nets for future maintenance.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The original estimate was related to the cost to re-coat the net once removed. When the net was being removed, a significant amount of sea grass was found to be tangled in the net which needed to be removed and required the net to be cut. The cost to repair the net as well as re-coat it is greater than the cost to purchase a new net; therefore a new net will be purchased. The cost of the new net is considered a capital expenditure, whereas the re-coating would have been an O&M expense.

Project Fiscal Expenditures:
(January 1, 2008 – December 31, 2008)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The existing turtle net will be removed to be recoated and the new net will be installed in the interim. The new net will serve as a backup.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) – O&M
Project No. 22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid / gas pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The baseline assessments were undertaken for the corporate hazardous liquid / gas pipelines and associated evaluations has been completed. One additional dig on Martin 30" pipeline has been conducted by Southern Cathodic Protection Company earlier this year and another one is planned for later this year. Martin Terminal 18" pipeline is scheduled for smart pig this year to determine the corrosion rate by comparing the tool's data to previous run dated 2003 for future appropriate countermeasures.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $154,465 (59.4%) higher than originally projected. The following additional project activities were identified after the original 2008 projections were filed:
1) An area with insufficient cover was identified along the Martin Terminal 30" pipeline with the length of 270 feet, which needs to be addressed to stay in compliance with DOT regulations.
2) One dig was performed on January 31, 2008 on the Martin Terminal 30" pipeline and another dig is scheduled for later this year after the peak season.
3) Corroded pipe-shoes on the Martin Terminal 30" above grade DOT piping were replaced. Thirty pipe-shoes were ordered to install, saddle and replace bad pipe-shoes.
4) The 2" supply and return lines to the Martin Terminal boilers were corroded badly and multiple holes were identified. Since the boilers are running with mineral oil and not with bunker C, a decision was made to remove the lines instead of replacing / repairing them.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
This is an ongoing project. Martin 18" dual (gas/oil) pipeline is due for in-line-inspection in December this year. Two assessment and evaluation digs, will be conducted following the in-line inspection (smart pig) as required. (As a DOT requirement after each in-line-inspection – smart pig – the data regarding the anomalies, dents, need to be validated by performing two, three and maybe even more as necessary confirmatory digs and conducting the direct assessment and inspection on the location of the detected anomalies). UTMs and magnetic particle testing is a part of these direct assessment. Since the inspection on Martin 18" pipeline will be implemented late November this year, the DOT confirmatory digs will be conducted in 2009.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are expected to be $40,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (Spill Prevention, Control, and Countermeasures) - O&M
Project No. 23

Project Description:
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- has a combined aboveground oil storage capacity of more than 1320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and

- which due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
As of January 1, 2008, the responsibility of managing the SPCC plans for all substations has been transferred from the Distribution Environmental Group to the Transmission Environmental Group. The revisions to approximately 625 SPCC plans are currently being conducted, and the plans are being rechecked for accuracy. Due to the transition of responsibilities, there were no oil diversionary structures installed at any substation from January to August, and none are expected to be installed for the remaining of 2008. However, diversionary structures are scheduled to be installed at certain substations in 2009. In addition, SPCC-required quarterly inspections of all substations are being performed.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $367,325 (94.9%) higher than originally projected, primarily due to expenditures for additional required facility upgrades that were identified during development of the SPCC plans. The additional upgrades include nitrogen blanketing systems for corrosion protection of double wall piping at Cape Canaveral, Putnam and Lauderdale Plants. These upgrades were not anticipated at the time FPL filed its original projections for 2008. In addition, work for new secondary containment for a transformer at Port Everglades was switched from Capital to O&M.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
Due to the large amount of quarterly substation inspections reports that are being generated, we are in the process of developing a complex data base to manage all the inspection information. This will provide us better efficiencies in managing this data. This data will link up with the data base currently being developed for the equipment leak repair program.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project expenditures for the period January 2009 through December 2009 are expected to be $688,000, which includes required updates to the Facility Response Plans.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Reburn – O&M
Project No. 24

Project Description:
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process divides the furnace into three zones.

In the 1996-97 time period, FPL invested a considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, and pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Installation of the Unit 1 & 2 reburn equipment is complete. The units are operating reliably and have completed the process of optimization. The new systems have achieved significant NOx emission reductions. The PMT Reburn O&M ECRC dollars cover all on-going burner and equipment maintenance costs associated with the project.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $499,997. No variance estimated.

Project Progress Summary:
(January 2008 - December 2008)
Unit 1 & Unit 2 are operating as referenced above. Final report is being compiled to present to DEP. We then agree on new permit limits for Nox. Once new limit is established, project is complete and expenditures will be based on runtime and available maintenance time. No variance forecasted.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project expenditures for the period January 2009 through December 2009 are expected to be $500,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pt. Everglades ESP Technology – O&M
Project No. 25

Project Description:
The requirements of the Clean Air Act direct the EPA to develop health-based standards for certain "criteria pollutants". i.e. ozone (O3), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The original Port Everglades Title V permit, issued in 1998, expired in 2003. The renewal permit issued January 1, 2004 is now expiring December 31, 2008. A renewal permit application has been submitted and is pending DEP review. The DEP's Title V permit for FPL Port Everglades plant requires FPL to install and maintain Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The ESP engineering design for Units 1–4 was completed in 2004. All four Units' ESPs were completed between 2005 and 2007 and are operational (O&M activities started in April 2005 for this project).

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $360,685 (15.3%) lower than originally projected. Fuel economics to date have dictated that the units at the Port Everglades Plant be run on gas due to fuel oil's rising costs. Consequently, fuel oil chemical additives usage has decreased and the ESPs have not had to be operated as much as was originally projected for 2008, which reduced the equipment deterioration and generated significantly less ash for disposal.

Project Progress Summary:
(January 2008 - December 2008)
Construction on all four electrostatic precipitators was completed and all four units ESPS are operational.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project expenditures for the period January 2009 through December 2009 are expected to be $2,276,313.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: UST Replacement/Removal – O&M
Project No. 26

Project Description:
The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.

UST Category-B tanks are tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have a secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST that shall have secondary containment if installed after December 10, 1990.

UST and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

FPL has six Category-A and two Category-B Storage Tank Systems that must be removed or replaced in order to meet the performance standards of Rule 61-761.500. In 2004 FPL will replace the two single-walled USTs located at the Turkey Point Nuclear Plant Units 1 and 2 with ASTs providing secondary containment (concrete walls and floor) surrounding the tanks. Also in 2004, FPL will remove one single-walled UST located at the Ft. Lauderdale Plant and will not replace the tank. In 2005-2006 FPL will replace the single-walled USTs located at the Area Office Broward (one UST in 2005), Customer Service East Office (one UST in 2006), Juno Beach Office (one UST in 2005), and General Office (2 USTs in 2005), with double-walled tanks providing electronic leak detection. Additionally, the AST to be installed at the Area Broward Office will be concrete vaulted.

The removal and replacement of the USTs will be performed by outside contractors. Additionally, closure assessments will be performed in accordance with 62-761.800 and closure assessment reports will be submitted to local Counties, and the Department of Environmental Services (DEP).

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
There were no activities in 2008.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are for 2008 are $0.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2009 to December 31, 2009)
There are no activities planned for 2009.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Lowest Quality Water Source (LQWS) – O&M
Project No. 27

Project Description:
Project Description:
Section 366.8255 of the Florida Statutes provides for the recovery through the ECRC of "environmental compliance costs" which are costs incurred in complying with "environmental rules or regulations." The LQWS Project is required in order to comply with permit conditions in the Consumptive Use Permits (CUPs) issued by the St. Johns River Water Management District (SJRWMD or the District)) for the Sanford Plant. Those permit conditions are intended to preserve Florida's groundwater, which is an important environmental resource. The permit conditions therefore "apply to electric utilities and are designed to protect the environment" as contemplated by section 366.8255. The SJRWMD adopted a policy in 2000 that, upon permit renewal, a user of the District's water is required to use the lowest quality of water that is technically, environmentally and economically feasible for its needs. This policy was implemented for the Sanford Plant in their current CUPs. For the Sanford facility, Condition 15 of CUP No. 9202, issued in June 2000, requires the lowest quality of water to be used that is feasible to meet the needs of the facility. The LQWS project at Sanford Plant is currently operational.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The project at the Sanford Plant is currently operational.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in project expenditures is $54,797 or 18.2% lower than originally budgeted. Unplanned maintenance and repairs were performed, which required having the system out of service.

Project Progress Summary:
(January 2008 - December 2008)
The project at the Sanford Plant is currently operational.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are expected to be $258,471 for the Sanford Plant.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

PROJECT TITLE: 316b
PROJECT No: 28

Project Description:
The Phase II Rule implements section 316 (b) of the Clean Water Act (CWA) for certain existing power plants that employ a cooling water intake structure and that withdraw 50 million gallons per day (MGD) or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans or other waters of the United States (WUS) for cooling purposes. The Phase II Rule establishes national requirements applicable to, and that reflect the best technology available (BTA) for, the location, design, construction and capacity of existing cooling water intake structures (CWIS) to minimize adverse environmental impact. The Phase II Rule has implications at the following FPL facilities: Cape Canaveral, Cutler, Fort Myers, Lauderdale, Port Everglades, Riviera, Sanford, Martin, Manatee and St. Lucie Power Plants.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
One-year biological sampling programs have been completed at Cape Canaveral, Cutler, Fort Myers, Port Everglades, Riviera, and St. Lucie Power Plants. The data collected during these studies have been analyzed and reported on and are being used to develop compliance strategies for each plant. The Proposal for Information Collection (PIC) for each plant were previously submitted the Florida Department of Environmental Protection and the US EPA. The second set of 316(b) submittals - CWA 316(b) Supporting Information Documents - were submitted in 2008 for Lauderdale and Port Everglades Plants. The CWA 316(b) Supporting Information Documents for Riviera and Ft. Myers will be submitted later in 2008.

Project Fiscal Expenditures:
(January 1, 2008 to Dec 30, 2008)
Project expenditures are estimated to be $1,048,591 (73.1%) lower than projected. This variance is primarily due to economies of scale achieved through developing the database and report formats for one plant and using them across all plants. Additional economies of scale were achieved by combining meetings. The remanding of the 316(b) Phase II Rule by the Second Circuit Court also resulted in the development of more streamlined reports and significantly reduced the meeting requirements projected in 2008. Finally, per Order No. PSC-04-0987-PAA-EI issued on October 11, 2004, $129,000 of 2007 expenses were credited to the 316(b) project for the netting of environmentally-related study costs assumed to be in base rates. This amount could not be determined until actual expenses for 2007 were available in early 2008.

Project Progress Summary:
(January 1, 2008 to December 30, 2008)
One-year biological sampling programs were completed at Cape Canaveral, Cutler, Fort Myers, Port Everglades, Riviera, and St. Lucie Power Plants. The second set of 316(b) submittals - CWA 316(b) Supporting Information Documents - were submitted in 2008 for Lauderdale and Port Everglades Plants to the FDEP.

Project Projections:
(January 1, 2009 to December 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are expected to be $607,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SCR Consumables - O&M
Project No. 29

Project Description:
The Manatee Unit 3 and Martin Unit 8 Expansion Project Final Orders of Certification under the Florida Power Plant Siting Act and the PSD Air Construction Permit require the installation of SCRs on each of the plants' four Heat Recovery System Generators (HRSG) for the control of nitrogen oxide (NOx) emissions. The Florida Department of Environmental Protection (FDEP) made the determination that the SCR system is considered Best Available Control Technology (BACT) for these types of units, with concurrence from the U.S. Environmental Protection Agency (EPA). The operation of the SCR will cause FPL to incur O&M costs for certain products that are consumed in the SCRs. These include anhydrous ammonia, calibration gases, and equipment wear parts requiring periodic replacement such as controllers, ammonia detectors, heaters, pressure relief valves, dilution air blower components, NOX control analyzers and components.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The SCR systems are operational on both Manatee Unit 3 and Martin Unit 8. The SCR Systems are not anticipated to become operational until 2009 at the SJRPP site.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in project expenditures is estimated to be $493,270 or 57.7% lower than projected. Estimates related to ammonia consumption by the SCRs at SJRPP related to CAIR compliance were inadvertently included in the original estimates for this project.

Project Progress Summary:
(January 2008- December 2008)
The SCR systems are operating reliably on both Manatee Unit 3 and Martin Unit 8. Our costs for 2008 will be more than originally estimated, due to the higher cost of the anhydrous ammonia.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures for the period January 2009 through December 2009 are expected to be $350,000 for PMR/PMT.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Hydrobiological Monitoring Program (HBMP) - O&M
Project No. 30

Project Description:
The Hydrobiological Monitoring Program is required by the Water Management District in the Conditions of Certification for the new Manatee Unit 3. The program involves the data collection of river chemistry, flow and vegetation conditions to demonstrate that the plant's withdrawals do not impact the environment in and along the river. The Hydrobiological Monitoring Program is a 10 year study which started in 2003 during the construction phase of Unit 3 and will be completed in 2013.

Project Accomplishments:
(January. 1, 2008 to December 31, 2008)
Continue with river monitoring, calibration, maintenance and data collection. Vegetative mapping, aerial photography and mapping was conducted in October 2007. Additional studies are being conducted during summer due to drought conditions and use of Emergency Diversion Schedule.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $20,401 (50.5%) lower than projected. The variance is primarily due to lower than projected costs for monitoring and reporting requirements.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
This is an ongoing project. Interpretive report due in 2009.

Project Projections:
(January 1, 2009 to December 31, 2009)
Project estimates for January 2009 through December 2009 are expected to be $40,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAIR – O&M
Project No. 31

Project Description:
The CAIR Project was initiated to implement strategies to comply with CAIR Annual and Ozone Season NOx emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, the costs for the operation of SCR's under construction on SJRPP Units 1 and 2, costs for the operation of the Scrubber and SCR being installed on Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in the new operating mode. FPL anticipates changing the operating mode of its four 800 MW units at Martin and Manatee Plants. The "study cost" so far to Aptech Engineering have been paid. They have identified several countermeasures that are being prioritized and scheduled for implementation in 2008 – 2011. The update to the Gas Turbine Peaking Unit are likely to change as a result of contractual guarantees related to necessary overhaul schedules, component and materials costs and labor estimates.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
All planned testing for 2008 has been scheduled. The testing at the Fort Myers site has been completed. The testing for the Port Everglades and the Fort Lauderdale GT power parks has been scheduled and will be completed by the third quarter of 2008.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $552,892 (30.8%) lower than projected. Installation of the Boiler and Main Steam Drains at the Martin and Manatee Plants associated with the 800 MW Unit Cycling Project was listed as an O&M expense in the original projections and was subsequently re-classified as a Capital expenditure.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The 800 MW Cycling Project identified countermeasures to assist with assuring operating reliability are currently in-progress with Project scope, Outage planning, and implementation for 2008 including; Condenser Tube replacements, Steam Turbine projects, Boiler projects, and Balance of Plant projects. The projected schedule to begin cycling is; PMR 2 in December 2009, PMR 1 in December 2010, with PMT 1 and PMT 2 scheduled for June 2010. The Power Generation Division is scheduled to complete the required testing at the Port Everglades, Fort Lauderdale & Fort Myers GT power parks by the third quarter of 2008. Additional required testing will occur in a five year cycle per the rule. FPL projects operation and maintenance costs for the SCR on SJRPP to begin in the first quarter of 2009 as construction is completed and the controls are put into service. O&M costs associated with the Scrubber and SCR's at plant Scherer will occur starting in 2012 when the construction is completed.

Project Projections:
(January 1, 2009 to December 31, 2009)
Total estimated 2009 O&M costs are $1,611,396.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: BART Project – O&M
Project No. 32

Project Description:
Conduct air dispersion modeling to determine the visibility impacts to Federally Mandated Class 1 Areas (National Parks, National Wilderness Areas, etc.) from FPL's BART-Eligible units. The Regional Haze Rule, renamed the Clean Air Visibility Rule, (CAVR) mandates that certain vintage electric generating units (ca. 1962-1977) install Best Available Retrofit Technology (BART) if it is shown, via modeling that a unit causes or contributes to visibility impairment in any Class 1 Area.

Project Accomplishments:
(January. 1, 2008 to December 31, 2008)

- Compile Emissions Inventory of BART-Eligible sources – Complete May 2006
- Perform modeling - First round complete June 2006
- Conduct BART Control Technology Analysis – Pending
- Prepare BART Application Packages – Fall 2006

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $1,355, whereas FPL did not anticipate any 2008 expenditures for this project originally. During negotiations with the Florida DEP regarding FPL's proposed compliance plan for BART at the Turkey Point Fossil plant in the first quarter of 2008, the Department requested additional information and analyses. To provide the requested information FPL needed to engage an air modeling consultant to analyze the visibility improvements related to FPL's plan.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
BART Application for exempt facilities (PCC, PMR, PMT, PPE, PRV) submitted to FDEP 1/31/07. BART Determination for PTF submitted to FDEP 1/31/07. FDEP requested additional information on PTF 2/26/07 which necessitated additional Golder support. Response to FDEP additional information submitted to FDEP 5/3/07.

Project Projections:
(January 1, 2009 to December 31, 2009)
Project estimates for Jan 2009 through December 2009 are expected to be zero. No additional modeling expenses are anticipated for 2009. PGD may incur engineering expenses regarding the installation of new cyclone separators for PTF 1&2 BART Determination. This will be determined at a later date.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Cooling Water System Inspection and Maintenance – O&M
Project No. 34

Project Description:
The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system at FPL's St. Lucie nuclear plant (the "Cooling System") such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled 850 net MWe units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie Plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie Plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion ("BO") that is to be issued by the National Oceanic and Atmospheric Administration ("NOAA") pursuant to section 7 of the ESA. NOAA will finalize the BO in 2007. NOAA sent the Nuclear Regulatory Commission ("NRC") a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes.

Project Accomplishments:
(January 8, 2008 thru December 31, 2008)
Inspections have been completed on all intake and discharge lines. Currently we are reviewing bids for the cleaning of the intake lines for SL2 fall 2007. We expect the cleaning to be completed prior to the end of the year. Should the cleaning not be completed in 2007 we will be continuing in the SL1 outage.

Project Fiscal Expenditures:
(January 8, 2008 to December 31, 2008)
Project expenditures are estimated to be $4,554,865 or 1030.5% higher than originally projected. This variance is primarily due to weather delays, whereby some scope of work has been carried over into 2008 instead of substantially completed in 2007 as originally projected. In addition, the level of effort required to remove concrete debris was greater than anticipated.

Project Progress Summary:
(January 8, 2008 to December 31, 2008)
The inspections of the ocean intakes and discharges were completed during the SL1 Spring 2007 outage in April and May. Cleaning of select areas of the three ocean intake pipes and velocity caps is scheduled for the SL2 outage planned for the Fall 2007, October 1- Dec 25.

Project Projections:
(January 1, 2009 to December 31, 2009)
Project estimates for January 2009 through December 2009 are expected to be $1,800,000. This projection is an estimate in anticipation of delays that may occur due to bad weather. Project work can only be performed during planned outages. Any weather delays that occur during the outage beginning in October 20, 2008, could prohibit the completion of work and would be deferred to the next outage, occurring in April 2009.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Plant Water System – O&M
Project No. 35

Project Description:
The Martin Drinking Water System is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for TTHM (trihalomethanes) and HAA5 (Haleo Acetic Acid). The upgrades to the potable water system will cause FPL to incur Capital costs for major component upgrades to the system in order to comply with the new requirements. These include Nano filtration, air stripping, carbon and multimedia filtration. The operation of the Potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The project was delayed pending meeting with the agency on proposed design. No O&M dollars for 2008. Contract has been awarded. Permit applications have been submitted. The agency is The increased estimate was due largely to the additional cost of the CEMS software upgrade. This upgrade was needed to meet the EPAs mandate of reporting in XML format starting 1/1/2009. Additionally the higher cost of replacement parts for the new model analyzers installed end of last year (2007) and first half of this year (2008) was factored in.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Zero Dollars estimated Project expenditures are estimated to be $0 versus an original projection of $17,000. The Florida DEP requested a meeting to discuss the proposed design and implementation plan, which has delayed the work schedule. Preliminary approval was given based on the proposed concept of treatment. Construction applications and fees have been submitted to the FDEP. Permit issuance is expected in July 2008.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
Zero Dollars estimated for 2008. The project was delayed pending meeting with the agency on proposed design.

Project Projections:
(January 1, 2009 to December 31, 2009)
The 2009 estimate remains at the current estimate of $17,000 for projected replacement used media beds.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low Level Radioactive Waste – O&M
Project No. 36

Project Description: The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste (LLW) such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. The Barnwell facility ceased accepting LLW from FPL June 30th, 2008. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN is to ensure construction of a LLW storage facility with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5 year period. This will allow continued uninterrupted operation of the PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN will also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Field work has been performed at PSL and PTN to determine the potential location for each site's LLW storage facility. Project planning is going forward. Conceptual designs for LLW storage facilities are being developed and evaluated by Engineering and Nuclear Projects. The Nuclear Projects Department has worked with each site's Radiation Protection Department to develop several measures to ensure LLW storage capability exists at PSL and PTN until the LLW storage facilities can be completed at PSL and PTN. For PSL this consists of the purchase of a LS3 portable Ground Shield, two rain covers and additional insertable cylindrical shielding for existing concrete Ground Shields to meet RP surface dose rate restrictions for the storage casks. For Turkey Point the interim measures being considered to ensure LLW storage capacity is available until a facility is constructed includes purchasing new rigging to allow safely moving existing ground shields so that they can be used to store LLW.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $120,271, versus an original estimate of $0. The original estimate assumed all costs were capital. The $120,271 represents estimated costs for compressing waste to smaller volume.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The project for PSL and PTN is on schedule. Initial scoping work is progressing and conceptual designs for LLW storage facilities are under development and evaluation to choose the optimal solution for each site. Interim measures to provide limited LLW storage capacity have been implemented to allow LLW storage until LLW storage facilities are completed at the sites. The PTN facility is still in the early stages of scope development due to the fact that the need for a LLW storage facility is not as urgent as PSL.

Project Projections:
(January 1, 2009 to December 31, 2009)
Project estimates for January 2009 through December 2009 are expected to be $1,000,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low NOx Burner Technology – Capital
Project No. 2

Project Description:
Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce NO_x emissions. The Dade, Broward and Palm Beach county areas were classified as "moderate non-attainment" by the EPA. FPL has six units in this affected area.

LNBT meets the requirement to reduce NO_x emissions by delaying the mixing of the fuel and air at the burner, creating a staged combustion process along the length of the flame. NO_x formation is reduced because peak flame temperatures and availability of oxygen for combustion is reduced in the initial stages.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
All six units are in service and operational.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $399 or 0.05% lower than projected.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
Dade, Broward and Palm Beach Counties have now been re-designated as "attainment" for ozone with air quality maintenance plans. This re-designation still requires that all controls, such as LNBT, placed in effect during the "non-attainment" be maintained.

The LNBT burners are installed at all of the six units and design enhancements are complete.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $787,974.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring System (CEMS) – Capital
Project No. 3b

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping and reporting of SO2, NOx and carbon dioxide (CO2) emissions, as well as volumetric flow, heat input, and opacity data from affected air pollution sources. FPL has 57 units which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants, opacity, heat input, 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. Periodically, these systems extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability.

Project Accomplishments (January 1, 2008 to December 31, 2008)
The 2006 Continuous Emission Monitoring System Capital Project necessary to replace the CEMS CO2 emission analyzers at FPL generating units have been installed and successfully recertified at all facilities with only Martin units 3 & 4 remaining. All of the applicable SO2 analyzers were successfully replaced by the 2 Qtr 2008.

Project Fiscal Expenditures: (January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $35,059 or 3.4% higher than projected. This variance is primarily due to the procurement of a much lower cost per unit pricing from the vendor (California Analytical). In addition, several installations and in-service dates shifted from 2007 to 2008 due to equipment availability delays and schedule changes.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
All of the analyzers have been installed and successfully recertified with only Martin units 3 & 4 remaining. These are scheduled for the third quarter of 2008.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $1,025,943.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Clean Closure Equivalency – Capital
Project No. 4b

Project Description:
In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed CCEDs for nine FPL power plants to demonstrate to the U.S. EPA that no hazardous waste or hazardous constituents remain in the soil or water beneath the basins which had been used in the past to treat corrosive hazardous waste. The basins, which are still operational as part of the wastewater treatment systems at these plants, are no longer used to treat hazardous waste.

To demonstrate clean closure, soil sampling and ground water monitoring plans, implementation schedules, and related reports must be submitted to the EPA. Capital costs are for the installation of monitoring wells (typically four per site) necessary to collect ground water samples for analysis.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $0.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $3,692.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital
Project No.5b

Project Description:
Florida Administrative Code (F.A.C.) Chapter 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

The capital project associated with complying with the new standards includes the installation of items for each tank such as liners, cathodic projection systems and tank high-level alarms.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Installation of new radar level detector on PMR 1 & 2 metering tank will be installed in the 4th quarter. Abandoned 8" and 12" underground fuel oil piping in the Port of Palm Beach was removed and the project completed.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $2,872, or 0.2% higher than projected.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
Installation of new radar level detector on PMR 1 & 2 metering tank will be installed in the 4th quarter. Abandoned 8" and 12" underground fuel oil piping in the Port of Palm Beach was removed and the project completed.

Project Projections:
(January 1, 2009 to December 31, 2009)
No new expenditures for 2009. Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $1,648,976.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Turbine Lube Oil Underground Piping to Above Ground – Capital
Project No. 7

Project Description:
In accordance with criteria contained in Chapter 62-762 of the Florida Administrative Code (F.A.C.) for storage of pollutants, FPL initiated the replacement of underground Turbine Lube Oil piping to above ground installations at the St. Lucie Nuclear Power Plant.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $2.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
This project is complete.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 is $1,517.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil Spill Cleanup/Response Equipment – Capital
Project No. 8b

Project Description:
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments (January 1, 2008 to December 31, 2008)
All equipment is being maintained and replaced as necessary to maintain compliance with regulatory guidelines for response readiness.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $5,408, or 6.4% higher than projected.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
All deadlines, both state and federal, have been met. Ongoing costs will be annual in nature and will consist of equipment upgrades/replacements. In 2008, PGD will have purchased the following: (1) boom reel, (2) Conex boxes, (1) 18-ft flatbed trailer, (1) oil mop skimmer, and other equipment to be determined. PGD continues to assess our oil spill readiness at all applicable Florida facilities and are is taking action based on these assessments.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $111,495.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Storm Water Runoff – Capital

Project No. 10

Project Description:
The new National Pollutant Discharge Elimination System (NPDES) permit, Permit No. FL0002206, for the St. Lucie Plant, issued by the United States Environmental Protection Agency contains new effluent discharge limitations for industrial-related storm water from the paint and land utilization building areas. The new requirements become effective on January 1, 1994. As a result of these new requirements, the effected areas will be surveyed, graded, excavated and paved as necessary to clean and redirect the storm water runoff. The storm water runoff will be collected and discharged to existing water catch basins on site.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $0.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $9,377.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Disposal of Non-Contaminated Liquid Waste – Capital
Project No.17b

Project Description:
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater Discharge Elimination & Reuse – Capital
Project No.20

Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants and the Dade County DERM requires Turkey Point and Cutler Plant wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
All activities are complete.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $236,106.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net – Capital
Project No. 21

Project Description:
The Turtle Net project says that FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service ("NMFS"). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. (The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years). Based on the number of captured turtles in 2001, the lethal take limit for loggerhead and green turtles in that year was six (references; Nuclear Regulatory Commission letter dated May 18, 2001 included as Exhibit 1, Document No. 1, Endangered Species Act Section 7 Consultation Biological Opinion Incidental Take Statement dated May 4, 2001 included as Exhibit 1, Document No. 2, Appendix B To Facility Operating License No. NPF-16 St. Lucie Unit 2, Environmental Protection Plan, Non-Radiological, Amendment No. 103 included as Exhibit 1, Document No. 3). In 2001, FPL experienced six lethal takings of loggerhead and green turtles at the St. Lucie Power Plant, indicating that its existing measures to limit such takings were performing marginally.

The existing net is in need of maintenance. To facilitate this work, a temporary net will be situated to allow removal of the existing net. The new net having been properly coated for UV protection and anti-fouling will be installed replacing the existing net. The existing net will be repaired and maintained as a spare to allow rotation of the nets for future maintenance.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The original estimate was related to the cost to re-coat the net once removed. When the net was being removed, a significant amount of sea grass was found to be tangled in the net which needed to be removed and required the net to be cut. The cost to repair the net as well as re-coat it is greater than the cost to purchase a new net; therefore a new net will be purchased.

Project Fiscal Expenditures:
(January 1, 2008 – December 31, 2008)
The variance is estimated to be $1,107, or 0.9% higher than originally anticipated due to a new net is required since the existing net was cut during removal.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The original estimate was related to the cost to re-coat the net once removed. When the net was being removed, a lot of sea grass was tangled in the net and the net needed to be cut to remove. The cost to re-coat and repair the net is greater than the cost to purchase a new net. The new net is considered a capital cost.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $137,914.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) - Capital
Project No.22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments: (January 1, 2008 to December 31, 2008)
No projects for 2008 cycle.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is estimated to be $14,717, or 100% lower than projected. The installation of leak detection devices at the Martin 30" pipeline has been postponed. Further analysis is being conducted on other technology options.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
No projects for 2008 cycle.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $6,395.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (Spill Prevention, Control, and Countermeasures) – Capital
Project No.23

Project Description:
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- Has a combined aboveground oil storage capacity of more than 1320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and

- Which due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Required facility upgrades have been identified, and contracts have been awarded to provide the engineering, procurement, and construction for the capital upgrades. The upgrades are scheduled to be completed by the end of 2008. Capital upgrades will be executed at the following facilities: Sanford Plant, Martin Plant, Martin Terminal, Port Everglades Plant, Manatee Plant, Manatee Terminal, Turkey Point Plant, and Cape Canaveral Plant.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $22,485 or 1.0% lower than projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
By the end of 2008, we plan to have all required facility upgrades completed. It should be noted that the current EPA compliance deadline for implementation of the SPCC plans is July 1, 2009.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $2,525,090.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Reburn – Capital
Project No.24

Project Description:
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process is shown conceptually in Figure 1 (see below), and divides the furnace into three zones.

In the 1996-97 time period, FPL invested a considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Installation of the Unit 1 and Unit 2 equipment is complete, started up and completed process optimization of the new systems to ensure minimal emissions. Unit 1 is out of warranty. Unit 2 is still under warranty.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in depreciation and return is $253,766, or 5.1% lower than projected.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
Unit 1 and 2 both completed.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $4,609,917.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pt. Everglades ESP Technology – Capital
Project No.25

Project Description:
The requirements of the Clean Air Act direct the EPA to develop health-based standards for certain "criteria pollutants". i.e. ozone (O_3), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to, issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The original Port Everglades Title V permit, issued in 1998, expires on December 31, 2003 and must be renewed. The DEP's Final Title V permit for FPL Port Everglades plant requires FPL to install Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
During June, all major mechanical and electrical work was completed. All contractor punchlist items for the ESP were completed. Restoration of the plant property and grounds started during June. A Project Punchlist has been formalized with the plant and is being pursued.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Estimated depreciation and return is $333,754 or 2.8% lower than projected. Combinations of factors have led to the projected decrease in fiscal expenditures. Taking into account the supply of electricity, as compared to customer demand throughout the fleet, unit efficiency has usually demanded these units run less than anticipated. In addition, fuel economics to-date have also demanded the consumption of the least expensive fuel source, primarily natural gas, requiring less operation from the ESP's as initially predicted for 2007. This combination of unit efficiency and fuel economics has further lead to reduced equipment deterioration, with less generation of ash for disposal, requiring less overall maintenance activities.

Project Progress Summary:
(January 2008 - December 2008)
Construction on the Unit 3 electrostatic precipitator was completed in spring 2007 as the Unit went operational in May 2007. Therefore, at this time, all four ESP's (Units 1 through 4) have construction activities completed and are operational. The Units 1, 2 and 4 precipitators met all performance guarantees and permit requirements. Preliminary results of Unit 3 performance test exceeded all performance guarantees. The Unit 1, 2 and 4 stack emissions were well below the new Title V permit requirements of .03 lb/mmbtu particulate and 20% opacity. Enclosure of ash truck loading bay is planned to contain fugitive airborne ash during truck loadings. The Ash Enclosure design, material and erection contract will be turned over to the plant for implementation (scheduled for Fall 2007).

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $11,251,101.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: UST Replacement/Removal – Capital
Project No. 26

Project Description:
The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.

UST Category-B tanks are tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have a secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST that shall have secondary containment if installed after December 10, 1990.

UST and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

FPL has six Category-A and two Category-B Storage Tank Systems that must be removed or replaced in order to meet the performance standards of Rule 61-761.500. In 2004 FPL will replace the two single-walled USTs located at the Turkey Point Nuclear Plant Units 1 and 2 with ASTs providing secondary containment (concrete walls and floor) surrounding the tanks. Also in 2004, FPL will remove one single-walled UST located at the Ft. Lauderdale Plant and will not replace the tank. In 2005-2006 FPL will replace the single-walled USTs located at the Area Office Broward (one UST in 2005), Customer Service East Office (one UST in 2006), Juno Beach Office (one UST in 2005), and General Office (2 USTs in 2005), with double-walled tanks providing electronic leak detection. Additionally, the AST to be installed at the Area Broward Office will be concrete vaulted.

The removal and replacement of the USTs will be performed by outside contractors. Additionally, closure assessments will be performed in accordance with 62-761.800 and closure assessment reports will be submitted to local Counties, and the Department of Environmental Services (DEP).

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
There were no activities in 2008.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Depreciation and return is estimated to be $66,966, versus an original estimate of $0.

Project Progress Summary:
(January 2008 - December 2008)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $65,488.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAIR Compliance – Capital
Project No. 31

Project Description:
The CAIR Project was initiated to implement strategies to comply with CAIR Annual and Ozone Season NOx emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, the installation of SCR's on SJRPP Units 1 and 2, installation of a Scrubber and SCR on Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in the new operating mode. FPL anticipates changing the operating mode of its four 800 MW units at Martin and Manatee Plants. The "study cost" so far to Aptech Engineering have been paid. They have identified several countermeasures that are being prioritized and scheduled for implementation in 2008 – 2011. Project completion is scheduled for the first quarter of 2009. The Scrubber and SCR installation on Scherer Unit 4 are projected to be completed in the first quarter of 2012. The update to the Gas Turbine Peaking Unit CEMS requirements identified the need to implement a revised CEMS monitoring program for those units which will now require CEMS under the CAIR program requirements. FPL has determined that the implementation of the Low Mass Emissions option under 40 CFR Part 75 as the preferred option. The CEMS installations will require emissions testing of representative units and the procurement and installation of a Continuous Emissions Monitor at the Port Everglades GTs, Lauderdale GTs and Fort Myers GTs.

Project Accomplishments:
(January. 1, 2008 to December 31, 2008)

- Completed B & V study of CAIR compliance options
- Completed 800 MW Cycling Engineering Study

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
The variance in the return on CWIP is estimated to be $2,200,113 or 37.3% higher than projected. The variance is primarily due to higher than projected material costs for structural steel and higher than projected labor costs for the SCR installation on Units 1 and 2 at SJRPP.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)

The 800 MW Cycling Project identified countermeasures to assist with assuring operating reliability are currently in-progress with Project scope, Outage planning, and implementation for 2008 including; Condenser Tube replacements, Steam Turbine projects, Boiler projects, and Balance of Plant projects. The projected schedule to begin cycling is; PMR 2 in December 2009, PMR 1 in December 2010, with PMT 1 and PMT 2 scheduled for June 2010.

Installation of the SCR on SJRPP Unit 2 is complete with the installation of the SCR on Unit 1 approximately 60% complete. Installation of the Scrubber and SCR on Scherer Unit 4 will be completed in 2012. foundation work for the controls has begun and construction of common plant equipment for the CAIR controls is also underway.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are expected to be $23,103,538.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAMR Compliance – Capital
Project No. 33

Project Description:
The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on March 15, 2005, imposing nation-wide standards of performance for mercury (Hg) emissions from existing and new coal-fired electric utility steam generating units. In addition to the CAMR, the Georgia Environmental Protection Division (EPD) adopted state specific rules as part of its Multi-Pollutant Rules requiring the installation of mercury controls on coal fired electric generating units within Georgia including all four units at Plant Scherer. The CAMR, and the Georgia Multi-Pollutant rule, are designed to reduce emissions of Hg through implementation of coal-fired generating unit Hg controls. In addition, CAMR requires the installation of Hg Continuous Emission Monitoring Systems (HgCEMS) to monitor compliance with the emission requirements. The State of Florida has begun the implementation of the requirements for reduction of Hg through rule making process. Plant St. John's River Power Park (SJRPP) Units 1 & 2, in which FPL has 20% ownership shares, are affected units under this rule and will require the installation of HgCEMS. Similarly the State of Georgia, in addition to the adoption of their state specific mercury reduction requirements under the Multi-Pollutant rule, has also begun their rule making process to implement the federal rule which will affect FPL's ownership share of Plant Scherer Unit 4 requiring the installation of HgCEMS and Hg controls.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
FPL completed the evaluation of mercury control options for Plant Scherer and approved the co-owner plan to proceed with the installation of a baghouse/sorbant-injection system on its ownership share of Plant Scherer. In June 2007 FPL issued a limited notice to proceed to the controls contractor BE&K. Contracts with engineering firm, Advatech, has been signed.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Estimated depreciation and return are $2,524,933, or 61.7% lower than projected. The variance is primarily a result of changes in project schedule for the baghouse and sorbent injection installation on Scherer Unit 4, which delayed equipment procurement and certain construction activities to future years.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The FPL CAMR project at Plant Scherer includes FPL's costs from the installation of a Baghouse, a mercury sorbant injection system with associated controls and material handling equipment, and capital additions to Plant Scherer common areas to accommodate sorbant delivery and storage and spent sorbant disposal. Mercury controls at Plant Scherer are being installed on all 4 units at the plant to comply with the Georgia Multi-Pollutant Rule. Installation of controls requires a specific sequence for the construction of the controls and material handling systems. To date engineering and design work for the baghouses and sorbant handling equipment was initiated in April of 2007 with design work completed in 2008. Installation of the mercury controls has begun on all four units at Plant Scherer including foundation work presently underway for Unit 4 controls. Foundation piles are being installed for Unit 4 controls while construction of common facility components of controls has also begun. Installation of the mercury monitor is projected to be completed by December 2008 with the baghouse on Unit 4 projected to be completed in early 2010. The FPL CAMR project at SJRPP includes FPL's costs from the installation of HgCEMS which have been completed on Units 1 and 2.

Project Projections:
(January 1, 2009 - December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for the period January 2009 through December 2009 are projected to be $5,934,022.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Cooling Water System Inspection and Maintenance – Capital
Project No. 34

Project Description:
The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system at FPL's St. Lucie nuclear plant (the "Cooling System") such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled 850 net MWe units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie Plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie Plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion ("BO") that is to be issued by the National Oceanic and Atmospheric Administration ("NOAA") pursuant to section 7 of the ESA. NOAA will finalize the BO in 2007. NOAA sent the Nuclear Regulatory Commission ("NRC") a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes.

Project Accomplishments:
(January 8, 2008 thru December 31, 2008)
Inspections have been completed on all intake and discharge lines. Currently we are reviewing bids for the cleaning of the intake lines for SL2 fall 2007. We expect the cleaning to be completed prior to the end of the year. Should the cleaning not be completed in 2007 we will be continuing in the SL1 outage.

Project Fiscal Expenditures:
(January 8, 2008 to December 31, 2008)
Depreciation and return are estimated to be $0.

Project Progress Summary:
(January 8, 2008 to December 31, 2008)
The inspections of the ocean intakes and discharges were completed during the SL1 Spring 2007 outage in April and May. Cleaning of select areas of the three ocean intake pipes and velocity caps is scheduled for the SL2 outage planned for the Fall 2007, October 1- Dec 25.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for January 2009 through December 2009 are expected to be $19,518.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Plant Drinking Water System Compliance – Capital
Project No. 35

Project Description:
The Martin Drinking Water System is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for TTHM (trihalomethanes) and HAA5 (Haleo Acetic Acid). The upgrades to the potable water system will cause FPL to incur Capital costs for major component upgrades to the system in order to comply with the new requirements. These include Nano filtration, air stripping, carbon and multimedia filtration. The operation of the Potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The Florida DEP requested a meeting to discuss the proposed design and implementation plan, which has delayed the work schedule. Preliminary approval was given based on the proposed concept of treatment. Construction applications and fees have been submitted to the FDEP. On 08/20/2008 FDEP South East District has requested additional information prior to granting permits for construction, project will be delayed until permitting is approved. Permit issuance is expected in September 2008.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Depreciation and return are estimated to be $4,574, or 31.5% lower than projected. The project approval delays have resulted in delay in implementation.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The project is awaiting the final construction approval by FDEP.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for January 2009 through December 2009 are expected to be $27,801.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low Level Radioactive Waste - Capital
Project No. 36

Project Description:
The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste (LLW) such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. The Barnwell facility ceased accepting LLW from FPL June 30th, 2008. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN is to ensure construction of a LLW storage facility with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5 year period. This will allow continued uninterrupted operation of the PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN will also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
Field work has been performed at PSL and PTN to determine the potential location for each site's LLW storage facility. Project planning is going forward. Conceptual designs for LLW storage facilities are being developed and evaluated by Engineering and Nuclear Projects. The Nuclear Projects Department has worked with each site's Radiation Protection Department to develop several measures to ensure LLW storage capability exists at PSL and PTN until the LLW storage facilities can be completed at PSL and PTN. For PSL this consists of the purchase of a LS3 portable Ground Shield, two rain covers and additional insertable cylindrical shielding for existing concrete Ground Shields to meet RP surface dose rate restrictions for the storage casks. For Turkey Point the interim measures being considered to ensure LLW storage capacity is available until a facility is constructed includes purchasing new rigging to allow safely moving existing ground shields so that they can be used to store LLW.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Depreciation and return are estimated to be $0.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The project for PSL and PTN is on schedule. Initial scoping work is progressing and conceptual designs for LLW storage facilities are under development and evaluation to choose the optimal solution for each site. Interim measures to provide limited LLW storage capacity have been implemented to allow LLW storage until LLW storage facilities are completed at the sites. The PTN facility is still in the early stages of scope development due to the fact that the need for a LLW storage facility is not as urgent as PSL.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (depreciation and return) for January 2009 through December 2009 are expected to be $27,338.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: DeSoto Next generation Solar Energy Center – Capital
Project No. 37

Project Description:
The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic generating facility which will convert sunlight directly into electric power. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility will utilize cutting edge solar panel technology. The project will involve the installation of the solar PV panels and tracking system and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
In May 2008, FPL received County zoning approval (through a special exception) to build the solar facility. An Environmental Resource Permit application was filed in June 2008. In June 2008, FPL retained an Engineering Procurement and Construction (EPC) Contractor to design and construct the facility.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Return on CWIP is estimated to be $29,115. The costs incurred through the end of June 2008 are $257,739. The expected costs for the remainder of 2008 are $6,038,824.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The ERP permit is expected to be issued by the Florida Department of Environmental Protection in November 2008. Engineering design is underway with site construction expected to commence in January 2009.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (return on CWIP) for January 2009 through December 2009 are expected to be $11,224,044. Projected costs for January 2009 through December 2009 are $166,429,700.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Space Coast Next generation Solar Energy Center - Capital
Project No. 38

Project Description:
The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW solar photovoltaic (PV) generating facility which will convert sunlight directly into electric power. The facility will utilize a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project will involve the installation of the solar PV panels and support structures and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
In June 2008, FPL entered into a long term lease with NASA for use of the land to build the solar facility. In July 2008, an Environmental Resource Permit application was filed with the Water Management District, and an Army Corps of Engineers Nationwide Permit application was filed. In July 2008, FPL retained an Engineering Procurement and Construction (EPC) Contractor to design and construct the facility.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Return on CWIP is estimated to be $4,681. The costs incurred through the end of June 2008 are $269,960, including approximately $37,000 expended in late 2007. The remaining costs for 2008 are expected to be $742,326.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The ERP and AOCE permits expected to be issued in January 2009. Engineering design is underway with site construction expected to commence in September 2009.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (return on CWIP) for January 2009 through December 2009 are expected to be $1,508,123. Projected costs for January 2009 through December 2009 are $27,030,686.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Next Generation Solar Energy Center - Capital
Project No. 39

Project Description:
The Martin Next Generation Solar Energy Center ("Martin Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam to be supplied by Martin Solar will be used to supplement the steam currently generated by the heat recovery steam generators. The project will involve the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors will track the sun to maintain the optimum angle to collect solar radiation. The collectors will concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Project Accomplishments:
(January 1, 2008 to December 31, 2008)
The project filed for the necessary permit modifications, the Site Certification Conditions of Certification and the Army Corp or Engineers Fill permit in May of 2008. The modification to the Fill permit was issued on July 28, 2008. The modified Conditions of Certification are expected to be issued by the Florida Department of Environmental Protection on August 21, 2008. The project commenced initial engineering in July, 2008.

Project Fiscal Expenditures:
(January 1, 2008 to December 31, 2008)
Return on CWIP is estimated to be $81,892. The costs incurred through the end of June, 2008 are $766,731, which includes $68,000 which was incurred in late 2007.

Project Progress Summary:
(January 1, 2008 to December 31, 2008)
The project has received its modified Fill permit from the Army Corps of Engineers and is expected to receive the modified conditions of certification shortly. Engineering has commenced along with procurement activities for the major equipment. All contracts are expected to be in place to support a construction start in January, 2009.

Project Projections:
(January 1, 2009 to December 31, 2009)
Estimated project fiscal expenditures (return on CWIP) for January 2009 through December 2009 are expected to be $11,788,849. Projected costs for January 2009 through December 2009 are $210,005,000.

Form 42-6P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2009 to December 2009

Rate Class	(1) Avg 12 CP Load Factor at Meter (%)	(2) GCP Load Factor at Meter (%)	(3) Projected Sales at Meter (KWH)	(4) Projected Avg 12 CP at Meter (KW)	(5) Projected GCP at Meter (KW)	(6) Demand Loss Expansion Factor	(7) Energy Loss Expansion Factor	(8) Projected Sales at Generation (KWH)	(9) Projected Avg 12 CP at Generation (kW)	(10) Projected GCP Demand at Generation (kW)	(11) Percentage of KWH Sales at Generation (%)	(12) Percentage of 12 CP Demand at Generation (%)	(13) Percentage of GCP Demand at Generation (%)
RS1/RST1	65.077%	61.696%	55,403,306,419	9,718,567	10,251,197	1.08663620	1.06901375	59,226,896,463	10,560,547	11,139,322	52.33820%	56.97040%	54.82339%
GS1/GST1/WIES1	64.480%	56.897%	6,219,248,803	1,101,055	1,247,798	1.08663620	1.06901375	6,648,462,497	1,196,446	1,355,902	5.87518%	6.45440%	6.67322%
GSD1/GSDT1/HLFT1 (21-499 kW)	76.435%	67.509%	24,942,068,687	3,725,073	4,217,613	1.08655195	1.06894858	26,661,788,803	4,047,485	4,582,656	23.56075%	21.83474%	22.55404%
OS2	95.627%	19.389%	18,498,130	2,208	10,891	1.05506701	1.04443473	19,320,090	2,330	11,491	0.01707%	0.01257%	0.05655%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	81.083%	71.599%	11,220,287,833	1,579,680	1,788,928	1.08535318	1.06805030	11,983,831,786	1,714,511	1,941,619	10.58999%	9.24918%	9.55589%
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000+ kW)	89.478%	80.072%	2,133,689,890	272,215	304,191	1.07696203	1.06151341	2,264,940,431	293,165	327,602	2.00150%	1.58152%	1.61233%
GSLD3/GSLDT3/CS3/CST3	93.476%	70.237%	261,545,665	31,941	42,509	1.02836156	1.02355239	267,705,691	32,847	43,715	0.23657%	0.17720%	0.21515%
ISST1D	111.786%	43.812%	0	0	0	1.05506701	1.04443473	0	0	0	0.00000%	0.00000%	0.00000%
ISST1T	111.422%	25.703%	0	0	0	1.02836156	1.02355239	0	0	0	0.00000%	0.00000%	0.00000%
SST1T	111.422%	25.703%	87,048,226	8,918	38,661	1.02836156	1.02355239	89,098,420	9,171	39,757	0.07874%	0.04947%	0.19567%
SST1D1/SST1D2/SST1D3	111.786%	43.812%	5,382,413	550	1,402	1.05506701	1.04443473	5,621,580	580	1,479	0.00497%	0.00313%	0.00728%
CILC D/CILC G	92.489%	85.912%	3,419,610,773	422,070	454,380	1.07580614	1.06089603	3,627,851,508	454,065	488,825	3.20589%	2.44952%	2.40581%
CILC T	93.565%	84.459%	1,493,300,492	182,193	201,835	1.02836156	1.02355239	1,528,471,292	187,360	207,559	1.35069%	1.01074%	1.02152%
MET	72.366%	60.064%	91,941,054	14,503	17,474	1.05506701	1.04443473	96,026,431	15,302	18,436	0.08486%	0.08255%	0.09073%
OL1/SL1/PL1	653.334%	48.943%	584,472,455	10,212	136,323	1.08663620	1.06901375	624,809,092	11,097	148,134	0.55214%	0.05986%	0.72906%
SL2, GSCU1	113.244%	112.649%	109,513,160	11,039	11,098	1.08663620	1.06901375	117,071,074	11,995	12,059	0.10345%	0.06471%	0.05935%
TOTAL			105,989,914,000	17,080,224	18,724,300			113,161,895,157	18,536,901	20,318,556	100.00%	100.00%	100.00%

Notes:
(1) AVG 12 CP load factor based on actual load research data
(2) GCP load factor based on actual load research data
(3) Projected KWH sales for the period January 2009 through December 2009
(4) Calculated: (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2007 demand losses
(7) Based on 2007 energy losses
(8) Col 3 * Col 7
(9) Col 1 * Col 6
(10) Col 2 * Col 6
(11) Col 8 / total for Col 8
(12) Col 9 / total for Col 9
(13) Col 10 / total for Col 10

Form 42-7P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of Environmental Cost Recovery Clause Factors
January 2009 to December 2009

Rate Class	(1) Percentage of KWH Sales at Generation (%)	(2) Percentage of 12 CP Demand at Generation (%)	(3) Percentage of GCP Demand at Generation (%)	(4) Energy Related Cost ($)	(5) CP Demand Related Cost ($)	(6) GCP Demand Related Cost ($)	(7) Total Environmental Costs ($)	(8) Projected Sales at Meter (KWH)	(9) Environmental Cost Recovery Factor ($/KWH)
RS1/RST1	52.33820%	56.97040%	54.82339%	$15,879,663	$34,685,789	$1,381,042	$51,946,494	55,403,306,419	0.00094
GS1/GST1	5.87518%	6.45440%	6.67322%	$1,782,557	$3,929,690	$168,103	$5,880,350	6,219,248,803	0.00095
GSD1/GSDT1/HLTF(21-499 kW)	23.56075%	21.83474%	22.55404%	$7,148,445	$13,293,839	$568,153	$21,010,437	24,942,068,687	0.00084
OS2	0.01707%	0.01257%	0.05655%	$5,180	$7,653	$1,425	$14,258	18,498,130	0.00077
GSLD1/GSLDT1/CS1/CST1/HLTF(500-1,999 kW)	10.58999%	9.24918%	9.55589%	$3,213,054	$5,631,258	$240,720	$9,085,032	11,220,287,833	0.00081
GSLD2/GSLDT2/CS2/CST2/HLTF(2,000+ kW)	2.00150%	1.58152%	1.61233%	$607,266	$962,891	$40,616	$1,610,773	2,133,689,890	0.00075
GSLD3/GSLDT3/CS3/CST3	0.23657%	0.17720%	0.21515%	$71,776	$107,885	$5,420	$185,081	261,545,665	0.00071
ISST1D	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00067
ISST1T	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00068
SST1T	0.07874%	0.04947%	0.19567%	$23,889	$30,122	$4,929	$58,940	87,048,226	0.00068
SST1D1/SST1D2/SST1D3	0.00497%	0.00313%	0.00728%	$1,507	$1,905	$183	$3,595	5,382,413	0.00067
CILC D/CILC G	3.20589%	2.44952%	2.40581%	$972,684	$1,491,362	$60,604	$2,524,650	3,419,610,773	0.00074
CILC T	1.35069%	1.01074%	1.02152%	$409,807	$615,378	$25,733	$1,050,918	1,493,300,492	0.00070
MET	0.08486%	0.08255%	0.09073%	$25,746	$50,259	$2,286	$78,291	91,941,054	0.00085
OL1/SL1/PL1	0.55214%	0.05986%	0.72906%	$167,521	$36,448	$18,366	$222,335	584,472,455	0.00038
SL2, GSCU1	0.10345%	0.06471%	0.05935%	$31,389	$39,397	$1,495	$72,281	109,513,160	0.00066
TOTAL				$30,340,484	$60,883,876	$2,519,074	$93,743,432	105,989,914,000	0.00088

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

(1) From Form 42-6P, Col 11
(2) From Form 42-6P, Col 12
(3) From Form 42-6P, Col 13
(4) Total Energy $ from Form 42-1P, Line 5b x Col 1
(5) Total CP Demand $ from Form 42-1P, Line 5b x Col 2
(6) Total GCP Demand $ from Form 42-1P, Line 5b x Col 3
(7) Col 4 + Col 5 + Col 6
(8) Projected KWH sales for the period January 2009 through December 2009
(9) Col 7 / Col 8 x 100

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080007-EI
ENVIRONMENTAL COST RECOVERY CLAUSE
FPL SUPPLEMENTAL CAIR/CAMR/CAVR FILING
APRIL 2, 2008

Per Order No. 07-0922-FOF-EI, issued on November 16, 2007, the discussion below provides FPL's current estimates of project activities and associated costs related to its Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR)/ BART Projects.

Clean Air Interstate Rule (CAIR) Compliance Project Update:

SJRPP SCR and Ammonia Injection Systems - The installation of Selective Catalytic Reduction Systems (SCR) and Ammonia Injection Systems on St. Johns River Power Park (SJRPP) Units 1 and 2 remains at $45.5 million. Construction of the SCRs is on schedule with the Unit 2 SCR nearing completion and Unit 1 ductwork fabrication and installation underway.

Estimated CAIR O&M expenses for 2008 and 2009 are $360,000 and $600,000 respectively. Estimated annual O&M expenses beginning 2012 are $1.2 million (FPL 20% ownership). O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment.

Scherer SCR and FGD - Current capital cost estimates for the installation of Wet Flue Gas Desulfurization (FGD) Scrubber and Selective Catalytic Reduction System (SCR) with Ammonia Injection System on Scherer Unit 4 is $392.6 million. The construction of plant infrastructure required for the reagent supply and waste by-product removal from the emission controls being implemented at Plant Scherer is currently underway and FPL's share of the costs for those facilities needed for support of Unit 4 are included in the project costs. Specific engineering and design work on the FGD & SCR for Unit 4 has begun and costs for these activities will be presented for review and recovery. The Scherer Unit 4 control installation costs were evaluated to ensure that the proposed project remains a prudent expenditure for FPL's customers, through an analysis that included projected future costs for CO2 and other emissions from Electric Generating Units (EGUs) as well as the project's emission control costs. The results of the study indicate that customers are projected to receive substantial savings though the implementation of the controls rather than prematurely shutting down Unit 4 in order to avoid incurring compliance costs.

Georgia Power Company has not provided O&M estimates for the SCR and FGD for 2012 and beyond. O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 6
COMPANY Florida Power & Light Co. (Direct)
WITNESS R. R. Labauve (RRL-1)
DATE 11-04-08

auxiliary equipment. O&M activities for the FGD include limestone consumption, limestone and by-product handling operation, FGD operations, FGD tower and auxiliary equipment maintenance.

800 MW unit cycling project - The 800 MW unit cycling project is currently underway, with anticipated completion in 2010 at the Martin and Manatee Plants. Mr. LaBauve introduced this project in his September 1, 2006 testimony and had subsequently provided an estimate for implementation of the projects with a total capital cost of $103.8 million. Project work at the Martin and Manatee Plants for 2008 will include condenser tube replacements, steam turbine projects, boiler projects, and balance of plant changes for one unit at each plant for a total estimated capital cost of $40.1 million and an estimated O&M expense of $1.7 million. Similar project work for the remaining 800 MW units at Martin and Manatee is planned for 2009 with an estimated Capital Cost of $41.2 million and an O&M cost estimated at $2.1 million. FPL plans to complete the project work at the Manatee and Martin plants in 2010 with an estimated total project cost of $104.8 million in Capital costs and $5.3 million in O&M expenses.

The Reburn and Low NOx Burner projects at Cape Canaveral, Port Everglades, Turkey Point and Putnam plants are still on hold.

Rule Challenge - FPL's appeal of the Division of Administrative Hearings (DOAH) ruling in favor of the Florida Department of Environmental Protection (FDEP) was denied on November 7, 2007. The Third District Court of Appeals ruled that the DOA was justified in determining that the FDEP CAIR rules were a valid exercise of delegated legislative authority. FPL is participating with other litigants in the federal appeal of the CAIR rule where the court has established a schedule for briefing the issues. Initial briefs were filed March 5, 2007 by FPL. In July 2007 FPL attorneys participated in the development of "reply briefs" to other litigants. Final briefs have now been submitted. Oral arguments were presented to the DC Circuit Court on March 25, 2008 and a final decision by the court is expected later in 2008.

CEMS Plan for GTs - The Low Mass Emitting (LME) Continuous Emissions Monitoring Systems (CEMS) have been installed at the Fort Myers, Port Everglades, and Fort Lauderdale Gas Turbine Parks as required by the Clean Air Interstate Rule (CAIR). The entire capital project was completed in 2007 with no additional capital expense expected at the current time.

During 2008, the CEMS systems must be tested to verify that they meet the EPA and DEP performance specifications for the CAIR program. It is anticipated that $65,000 will be spent on these testing activities. The testing activities will be required every five years at current operating conditions. In addition, it is anticipated that $5,000 per year will be spent on routine maintenance of the CEMS systems. It should be noted that the LME option is available for a gas turbine only if its emissions remain under EPA-prescribed thresholds. If any gas turbine emits more than 50 tons of NOx or 25 tons of SO2 in a given calendar year, the testing for that gas turbine will be required every year,

instead of every 5 years. That would increase the testing costs for non-qualifying gas turbines to $65,000 per year, along with $5,000 per year for maintenance.

Purchases of allowances - Future purchases of allowances will be made as needed for compliance with the annual and ozone season NOx requirements. FPL has revised its estimate to reflect the changes which were made in the projected operation of FPL fossil generating units and purchase power. Reductions in NOx emissions from the implementation of the 800 MW unit cycling project have been included in the forecasted unit emissions. FPL's revised estimate projects a shortage of both NOx Ozone Season and NOx Annual Allowances for the initial 2009 and 2010 compliance years, but projects an excess of annual NOx allowances in subsequent years. FPL has projected Ozone Season NOx Allowance compliance costs of $1.2 million and $0.3 million in 2009 and 2010 respectively. FPL also projects Annual NOx Allowance compliance costs of $10.3 million and $2.7 million for 2009 and 2010 respectively. FPL projects an excess of both NOx Ozone Season and NOx Annual Allowances beginning in 2011 and continuing in subsequent years as a result of reductions in system emissions as the West County Energy Center Units come on line. FPL has estimated an average annual excess of approximately $14.8 Million for the 2011 through 2020 period. Please note, however, that FPL's actual NOx allowance requirements depend upon a number of factors that are difficult to predict, and it is possible that FPL's actual allowance requirements will differ significantly from the future year allowance projection. It is also likely that the future actual prices for the NOx allowances will differ substantially from the projected prices.

Climate Change - FPL continues to monitor the development of CO2 compliance policy and regulation as it relates to electric generating facilities. FPL believes that the future implementation of CO2 regulation on power plants may become an important consideration in the evaluation and implementation of pollution controls on generating units including those required to comply with CAIR and the Georgia Multi-pollutant rule. On July 13, 2007 Governor Charlie Christ signed three Executive Orders initiating Florida's energy policy: Executive Order 07-126, titled "Leadership by Example: Immediate Actions to Reduce Greenhouse Gas Emissions from Florida State Government"; Executive Order 07-127, "Immediate Actions to Reduce Greenhouse Gas Emissions within Florida"; and Executive Order 07-128, "Florida Governor's Action Team on Energy and Climate Change." Executive Order 07-127 directed the FDEP to initiate rulemaking to establish maximum emission levels of greenhouse gases for electric utilities. The standard will require a reduction of emissions to 2000 levels by 2017, to 1990 levels by 2025, and by 80 percent of 1990 levels by 2050. The FDEP proposes to create new rule Chapter 62-285, F.A.C., Greenhouse Gas Emissions Reduction, and develop new Rule 62-285.300, F.A.C., Electric Utility Greenhouse Gas Reduction Program, to accomplish this purpose. The effect of the rule would be to reduce greenhouse gas emissions from EGUs. The FDEP held two workshops in 2007 for the development of rule 62-285 to implement the Governor's executive order 07-127 to provide an opportunity for comments and recommendations at the outset of the proposed rule development projects. The FDEP did not offer any rule proposals at these workshops. FPL is participating in the Rule Development Workshops to represent the interests of its customers.

Specific rulemaking has not been proposed by the FDEP detailing how electric utilities would be impacted by the new rule, including the point of regulation for the Greenhouse Gas emissions. FPL has evaluated its present CO2 emissions from electric generation including the projected emissions through 2017. Future reductions of CO2 emissions may be required depending on the final rule. FPL is currently evaluating strategies which can be implemented to reduce CO2 emissions which include, but not limited to: expansion of nuclear generation; expanded use of Demand Side Management and Energy Efficiency programs; repowering of existing fossil generating plants; an increased use of renewable generation that includes solar, wind, and biomass; Carbon Capture and Sequestration at fossil generating plants. As FPL evaluates its needs for additional generating sources in its annual planning cycle during the preparation of the Ten Year Site Plan, the Greenhouse Gas emissions from existing and new sources will be evaluated for compliance with the targets established within the Governor's Executive Order 07-127.

FPL has not proposed a specific project at this time for compliance with the Governor's Executive Order. FPL anticipates that if reductions are required to comply with the targets established in a new rule to implement the order, specific projects may be required to reduce emissions below the current projected emissions from the generation of electricity to meet the customer demand. If FPL has to reduce emissions, specific projects will be identified to provide the reductions required to meet the CO2 targets. These will be provided to the Commission with the appropriate details and costs for review. FPL has conducted a review of the 800 MW cycling project, the Plant Scherer CAIR and Mercury controls, and the SJRPP CAIR and Mercury projects and has concluded that the continuation of the projects would be more cost effective than the alternative of discontinuing those projects.

Actual CAIR Capital expenses through 2007 are $26.1 million.

CAIR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2008**	**2009**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	17.0	7.9	45.5
Scherer-SCR/FGD	45.6	90.6	392.6
800 MW Unit Cycling - Martin	24.4	22.7	50.1
800 MW Unit Cycling - Manatee	15.7	18.5	54.7
CEMS at GTs	Capital project completed	Capital project completed	Capital project completed
Allowances	N/A	N/A	N/A
CO2 Compliance	Not yet available	Not yet available	Not yet available

Actual CAIR O&M expenses through 2007 are $1.8 million.

CAIR O&M COST ESTIMATES ($Millions)			
PROJECT	**2008**	**2009**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	.360	.600	$1.2 (2012+ annual operating costs are on-going)
Scherer-SCR/FGD	0	0	Not yet available
800 MW Unit Cycling – Martin	.890	1.1	2.4
800 MW Unit Cycling – Manatee	.842	1.016	2.9
CEMS at GTs	0.070	0.005	0.075
Allowances	0	11.5	N/A
CO2 Compliance	Not yet available	Not yet available	Not yet available

Note: FPL is projecting $3.0 million for purchases of allowances in 2010.

Clean Air Mercury Rule (CAMR) Compliance Project Update:

On February 8, 2008 the U.S. District Court of Appeals ruled that EPA's delisting rule for Mercury emissions from coal-fired EGUs utility boilers and the Clean Air Mercury Rule were unlawful and vacated both rules. EPA may appeal the decision of the Court of Appeals before the Supreme Court prior to March 24, 2008. The vacature of the CAMR rule places in jeopardy the rules of many states, including Florida and Georgia that had been approved to implement the CAMR requirements using the federal rule as the enforceable standard.

The Georgia Environmental Protection Division (EPD) promulgated two major rules to implement mercury reductions within Georgia that included a rule to adopt the CAMR federal mercury cap and trade program: Rule 391-3-1-.02(15) – "*Georgia Mercury Trading Rule*" and a Georgia state specific Multi-pollutant rule: Rule 391-3-1-.02(2)(sss) – " *Multipollutant Control for Electric Utility Steam Generating Units*". The Multipollutant rule was promulgated to specify the implementation of specific air pollution control equipment for reductions in mercury, sulfur dioxide, and nitrogen oxides emissions from coal-fired EGUs. The rule requires controls to be implemented on specific EGUs within the state to control the emissions of Sulfur Dioxide (SO2), Nitrogen Oxides (NOx) and mercury (Hg). Section 4(i) of the Multipollutant Rule requires that Scherer Unit 4 may not be operated after April 30, 2010, unless it is equipped and operated with sorbent injection and a baghouse. A copy of the relevant sections of 391-3-1-.02(2) (sss) have been provided as Exhibit 1.

With the vacature of the Delisting rule EPA is now likely to proceed with evaluation and implementation of the existing rule requiring Maximum Available Control Technology (MACT) for mercury emissions from coal-fired EGUs. Prior to the implementation of

the Delisting and CAMR rules the MACT analyses had determined that the use of sorbant injection systems were effective in the removal of mercury and established the CAMR Phase I and II mercury budgets based on the implementation of the technology on coal-fired EGUs by 2018. The Georgia Multipollutant rule requires that each of the four units at Plant Scherer implement a Sorbant injection system with a baghouse collection device for removal of mercury. Therefore, installation of the mercury controls that would have been needed to comply with the CAMR requirements remains necessary to comply with the requirements of the Georgia Multipollutant rule, so the vacature of CAMR does not change the compliance obligations at Plant Scherer, including FPL's share of Unit 4. Installation of the Mercury Continuous Emissions Monitoring System (HgCEMS) that was planned to comply with CAMR likewise will be needed to comply with the monitoring and reporting requirements of the Multipollutant rule and ultimately to demonstrate compliance with monitoring of the final MACT rule. Specifically, FPL will comply with the mercury reduction requirements of the Georgia Multi-Pollutant rule using the following projects identified previously under CAMR:

1. Installation of Fabric Filter Bag House and Mercury Sorbant Injection System on Scherer Unit 4.
2. Installation of HgCEMS on Scherer Unit 4.
3. Installation of HgCEMS on SJRPP Units 1 & 2 that are currently under construction (certification testing and operation delayed until the monitoring requirements begin for Mercury MACT compliance.)

FPL has revised the cost estimates for the installation of mercury controls at plant Scherer as a result of estimated increases in labor and material costs.

FPL plans to petition the Commission for approval of a modification to its Clean Air Mercury Rule (CAMR) Project to recognize that the activities planned for Plant Scherer to comply with the now-vacated CAMR will be implemented instead to comply with the Georgia Multi-Pollutant Rule. FPL continues to believe that mercury controls being installed at Plant Scherer to comply with the Georgia rule will be equivalent to those which are likely to be required under a MACT rule. For the SJRPP units FPL, and majority owner JEA, had planned to comply with the Phase I of the CAMR through the co-benefits removal of mercury by the SCR and Scrubber for units burning bituminous coals. The planned addition of the SCR on both SJRPP units to comply with CAIR would achieve the co-benefit reductions as both units had been constructed with Scrubbers installed. FPL will evaluate the future mercury control requirements for Plant Scherer and SJRPP as the EPA reviews its options in response to the CAMR vacature. FPL and JEA will evaluate the appropriate technology for implementation at SJRPP to comply with a future Mercury reduction requirement.

Actual CAMR Capital expenses through 2007 are $6.0 million.

CAMR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2008**	**2009**	**TOTAL PROJECT**
SJRPP-Mercury CEMS	.060	0	.475
Scherer-Sorbant Injection/Baghouse/ Mercury CEMS	40.0	49.5	99.6

Clean Air Visibility Rule (CAVR) / Best Available Retrofit Technology (BART) Project Update:

FPL has successfully demonstrated through modeling that all the applicable units under the particulate control portion of the BART regulations, with the exception of Turkey Point Units 1 & 2, do not cause a significant amount of particulate visibility impairment. Due to this demonstration, no further action will be required to comply with particulate emissions, except at Turkey Point Units 1&2.

Negotiations are continuing with the FDEP regarding Turkey Point Units 1 & 2. The last information provided to the FDEP revolved around two different compliance options for particulate control:

1. Installation of Electrostatic Precipitators (ESPs)
2. Alternative Emission Reduction Strategy
    a. Installation of modern multi-cyclone separators, and
    b. Switching to a lower sulfur fuel (1.0% to 0.7%)

FPL continues discussions with the FDEP to convince the agency that ESPs are not reasonable due to significant capital and on-going O&M costs. The multi-cyclone separators and fuel option provides more visibility improvement at a much lower overall cost.

The two projects compare as follows:

1. ESPs - $92 MM Capital with $13MM increased O&M/year
2. Alternative Emission reduction strategy - $7.3 MM Capital with $1.9MM increased O&M/Year

The FDEP's final decision is expected by May 2008. Once the final requirements have been determined, the required implementation date will not be until December 2013. However, installation will be conducted using a staged approach, with work done during the unit outages currently scheduled between now and 2013, in order to minimize effect on total system load and availability.

By December 2012, FPL will be required by the FDEP's Reasonable Further Progress rule to submit additional CAVR reduction evaluations for sulfur dioxide emissions from the following units:

1. Turkey Point Units 1 & 2
2. Port Everglades Units 3 & 4
3. Manatee Units 1 & 2

FPL is considering various option strategies to achieve the required reductions in sulfur dioxide emissions from these eight units cost-effectively. At this time the cost of compliance for the required sulfur dioxide emissions is not known. It should be noted that there is a potential that future sulfur dioxide emission controls required for CAVR compliance would provide co-benefit to the Company for compliance with CAIR.

Actual CAVR Capital expenses through 2007 are $0.0. Capital estimates for 2008 and beyond for Turkey Point Units 1 & 2 Particulate Control efforts and SO2 reductions at Turkey Point Units 1&2, Port Everglades Units 3&4, and Manatee Units 1&2 are not yet available.

Actual CAVR O&M expenses through 2007 are $0.040 Million. O&M estimates for 2008 are $20,000 for negotiations with the FDEP. O&M estimated for 2009 are undetermined.

Executive Order 07-127

STATE OF FLORIDA
OFFICE OF THE GOVERNOR
EXECUTIVE ORDER NUMBER 07-127

Establishing Immediate Actions to Reduce Greenhouse Gas Emissions within Florida

WHEREAS, with nearly 1,350 miles of coastline and a majority of citizens living near that coastline, Florida is more vulnerable to rising ocean levels and violent weather than any other state; and

WHEREAS, global climate change is one of the most important issues facing the State of Florida this century; and

WHEREAS, Florida is the second fastest growing state in the union with respect to the annual increase of new greenhouse gas emissions; and

WHEREAS, immediate actions are available and required to reduce emissions of greenhouse gases within Florida; and

WHEREAS, efforts are underway at the national level to begin addressing greenhouse gas emissions; and

WHEREAS, Florida has committed to becoming a leader in reducing emissions of greenhouse gases which are causing changing Earth's climate; and

WHEREAS, Florida, together with international leaders and experts, is hosting the Serve to Conserve Climate Change Summit on July 12 and 13,2007 in Miami, Florida;

NOW, THEREFORE., I, CHARLIE CRIST,

as Governor of Florida, in obedience to my solemn constitutional duty to take care that the laws be faithfully executed, and pursuant to the Constitution and laws of the State of Florida, do hereby promulgate the following Executive Order, to take immediate effect:

Section 1. I hereby establish greenhouse gas emission reduction targets for the State of Florida as follows: by 2017, reduce greenhouse gas emissions to 2000 levels; by 2025, reduce greenhouse gas emissions to 1990 levels; by 2050, reduce greenhouse gas emissions by 80% of 1990 levels.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 7
COMPANY FL Power & Light Co. (Direct)
WITNESS R. R. Labauve (RRL-2)
DATE 11-04-08

Section 2. I hereby direct the following actions by members of my Administration in order to produce immediate reductions in greenhouse gas emissions within Florida;

1. The Secretary of Environmental Protection shall immediately develop rules as authorized under Chapter 403, Florida Statutes, to achieve the following:
    - Adoption of a maximum allowable emissions level of greenhouse gases for electric utilities in the State of Florida. The standard will require at minimum, three reduction milestones as follows: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; by 2050, emissions not greater than 20% of Year 1990 utility sector emissions (i.e., 80% reduction of 1990 emissions by 2050); Adoption of the California motor vehicle emission standards in Title 13 of the California Code of Regulations, effective January 1,2005, upon approval by the U.S. Environmental Protection Agency of the pending waiver, which includes emission standards for greenhouse gases, submitted by the California Air Resources Board; and Adoption of a statewide diesel engine idle reduction standard.
2. The Secretary of Community Affairs shall immediately:
    - Convene the Florida Building Commission for the purpose of revising the Florida Energy Code for Building Construction to increase the energy performance of new construction in Florida by at least 15% from the 2007 Energy Code. The Commission should consider incorporating standards for appliances and standard lighting in the Florida Energy Code. Target implementation date for the revised Florida Energy Code for Building Construction is January 1, 2009;
    - Initiate rulemaking of the Florida Energy Conservation Standards, Chapter 9B-44, Florida Administrative Code, with an objective to increase the efficiency of applicable consumer products authorized under s. 553.957, Florida Statutes, by 15% from current standards for implementation by July 1,2009.

Section 3. I hereby request the Florida Public Service Commission to take the following actions for the electric utility sector in order to open the market to clean, renewable energy technologies, thus avoiding future greenhouse gas emissions:

- Not later than September 1,2007, initiate rulemaking to require that utilities produce at least 20% of their electricity from renewable sources (Renewable Portfolio Standard) with a strong focus on solar and wind energy;

- Not later than September 1, 2007, initiate rulemaking to reduce the cost of connecting solar and other renewable energy technologies to Florida's power grid by adopting the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems as the uniform statewide interconnection standard for all utilities; and

- Not later than September 1,2007, initiate rulemaking to authorize a uniform, statewide method to enable residential and commercial customers who generate electricity from on-site renewable technologies of up to 1 megawatt in capacity to offset their consumption over a billing period by allowing their electric meters to tum backwards when they generate electricity (net metering).

Section 4. All state agencies departments under the direction of the Governor are hereby directed, and all other state agencies are hereby requested, to assist those carrying out the directions in this Executive Order.

IN TESTIMONY WHEREOF, I have hereunto set my hand and have caused the Great Seal of the State of Florida to be affixed at Tallahassee, The Capitol, this 13th day of July,

Governor: Charlie Crist

ATTEST:

Secretary of State: Kurt S. Browning

CHAPTER 2008-227

HOUSE BILL NO. 7135

An act relating to energy; amending s. 74.051, F.S.; providing that it is the intent of the Legislature for a court, when practicable, to conduct a hearing and issue an order on a petition for a taking within a specified time; amending s. 110.171, F.S.; requiring each state agency to complete a telecommuting program by a specified date which includes a listing of the job classifications and positions that the state agency considers appropriate for telecommuting; providing requirements for the telecommuting program; requiring each state agency to post the telecommuting program on its Internet website; amending s. 163.04, F.S.; clarifying that condominium declarations may not prohibit renewable energy devices; removes three-story height restriction for installation of solar collectors on condominiums; amending s. 186.007, F.S.; authorizing the Executive Office of the Governor to include in the state comprehensive plan goals, objectives, and policies related to energy and global climate change; amending s. 187.201, F.S.; expanding the air quality, energy, and land use goals of the State Comprehensive Plan to include the development of low-carbon-emitting electric power plants, the reduction of atmospheric carbon dioxide, the promotion of the use and development of renewable energy resources, and provide for the siting of low carbon emitting electric power plants, including nuclear plants; amending ss. 196.012 and 196.175, F.S.; deleting outdated, obsolete language; removing the expiration date of the property tax exemption for real property on which a renewable energy source device is installed and revising the options for calculating the amount of the exemption; amending s. 206.43, F.S.; requiring each terminal supplier, importer, blender, and wholesaler to provide in a report to the Department of Revenue the number of gallons of blended and unblended gasoline sold; amending s. 212.08, F.S.; revising the definition of "ethanol"; specifying eligible items as limited to one refund; requiring a person who receives a refund to notify a subsequent purchaser of such refund; transferring certain duties and responsibilities from the Department of Environmental Protection to the Florida Energy and Climate Commission; requiring the Florida Energy and Climate Commission to adopt, by rule, an application form for claiming a tax exemption; amending s. 220.191, F.S.; providing that certain qualifying projects are eligible to transfer capital investment tax credits to other businesses under certain circumstances; providing limitations on the use of such transferred credits; specifying requirements for such transfers; amending s. 220.192, F.S.; defining terms related to a tax credit; allowing the tax credit to be transferred for a specified period; providing procedures and requirements; requiring the Department of Revenue to adopt rules for implementation and administration of the program; transferring certain duties and responsibilities from the Department of Environmental Protection to the Florida Energy and Climate Commission; amending s. 220.193, F.S.; defining the terms "sale" or "sold"; defining the term "taxpayer"; providing for retroactivity; providing that

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the use of the renewable energy production credit does not reduce the alternative minimum tax credit; amending s. 253.02, F.S.; authorizing the Board of Trustees of the Internal Improvement Trust Fund to delegate authority to grant easements across lands owned by the Board of Trustees of the Internal Improvement Trust Fund to the Secretary of Environmental Protection under certain conditions; amending s. 255.249, F.S.; requiring state agencies to annually provide telecommuting plans to the Department of Management Services; amending s. 255.251, F.S.; creating the "Florida Energy Conservation and Sustainable Buildings Act"; amending s. 255.252,

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 8
COMPANY Florida Power+Light Co. (Direct)
WITNESS R. R. Labauve (RRL-3)
DATE 11-04-08

F.S.; providing findings and legislative intent; providing that it is the policy of the state that buildings constructed and financed by the state be designed to meet the United States Green Building Council (USGBC) Leadership in Energy and Environmental Design (LEED) rating system, the Green Building Initiative's Green Globes rating system, the Florida Green Building Coalition standards, or a nationally recognized green building rating system as approved by the department; requiring each state agency occupying space owned or managed by the department to identify and compile a list of projects suitable for a guaranteed energy, water, and wastewater performance savings contract; amending s. 255.253, F.S.; defining terms relating to energy conservation for buildings; amending s. 255.254, F.S.; prohibiting a state agency from leasing or constructing a facility without having secured from the department a proper evaluation of life-cycle costs for the building; amending s. 255.255, F.S.; requiring the department to use sustainable building ratings for conducting a life-cycle cost analysis; amending s. 255.257, F.S.; requiring all state agencies to adopt an energy efficiency rating system as approved by the department for all new buildings and renovations to existing buildings; requiring all county, municipal, school district, water management district, state university, community college, and Florida state court buildings to meet certain energy efficiency standards for construction; providing applicability; creating a sustainable building training certification program within St. Petersburg College; specifying program components; creating s. 286.29, F.S.; requiring the Department of Management Services to develop the Florida Climate-Friendly Preferred Products List; requiring state agencies to consult the list and purchase products from the list if the price is comparable; requiring state agencies to contract for meeting and conference space with facilities having the "Green Lodging" designation; authorizing the Department of Environmental Protection to adopt rules; requiring the department to establish voluntary technical assistance programs for various businesses; requiring state agencies, state universities, community colleges, and local governments that purchase vehicles under a state purchasing plan to maintain vehicles according to minimum standards and follow certain procedures when procuring new vehicles; requiring state agencies to use ethanol and biodiesel-blended fuels when available; amending s. 287.063, F.S.; prohibiting the payment term for equipment from exceeding the useful life of the equipment unless the contract provides for the replacement or the extension of the useful

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life of the equipment during the term of the loan; amending s. 287.064, F.S.; authorizing an extension of the master equipment financing agreement for energy conservation equipment; requiring the guaranteed energy, water, and wastewater savings contractor to provide for the replacement or the extension of the useful life of the energy conservation equipment during the term of the contract; amending s. 287.16, F.S.; requiring the Department of Management Services to analyze specified fuel usage by the Department of Transportation; amending s. 288.1089, F.S.; defining the term "alternative and renewable energy"; revising provisions relating to innovation incentive awards to include alternative and renewable energy projects; specifying eligibility requirements for such projects; requiring Enterprise Florida, Inc., to solicit comments and recommendations from the Florida Energy and Climate Commission in evaluating such projects; amending s. 316.0741, F.S.; requiring all hybrid and other low-emission and energy-efficient vehicles that do not meet the minimum occupancy requirement and are driven in a high-occupancy-vehicle lane to comply with federally mandated minimum fuel economy standards; authorizing specified vehicles to use certain high-occupancy-vehicle lanes without payment of tolls; amending s. 337.401, F.S.; requiring the Department of Environmental Protection to adopt rules relating to the placement of and access to aerial and underground electric transmission lines having certain specifications; defining the term "base-load generating facilities"; amending s. 339.175, F.S.; requiring each metropolitan planning organization to develop a long-range transportation plan and an annual project priority list that, among other considerations, provide for sustainable growth and reduce greenhouse gas emissions; amending

s. 350.01, F.S.; conforming the beginning of a Public Service Commission member's term as chair with the beginning of terms of commissioners; correcting cross-references; amending s. 350.012, F.S.; renaming the Committee on Public Service Commission Oversight, a standing joint committee of the Legislature, as the "Committee on Public Counsel Oversight"; deleting the committee's authority to recommend to the Governor nominees to fill vacancies on the Public Service Commission; amending s. 350.03, F.S.; clarifying the power of the Governor to remove and fill commission vacancies as set forth in the State Constitution; amending s. 350.031, F.S.; increasing the number of members on the council; requiring the President of the Senate and the Speaker of the House of Representatives to appoint a chair and vice chair to the council in alternating years; removing spending authority for the council to advertise vacancies; requiring the council to submit recommendations for vacancies on the Public Service Commission to the Governor; requiring the council to nominate a minimum of three persons for each vacancy; revising the date that recommendations for vacancies must be submitted; providing that a successor Governor may remove an appointee only as provided; providing for the council to fill a vacancy on the commission if the Governor fails to do so; authorizing a successor governor to recall an unconfirmed appointee under certain circumstances; amending ss. 350.061 and 350.0614, F.S., relating to the appoint

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ment, oversight, and compensation of the Public Counsel; conforming provisions to changes made by the act; amending s. 366.04, F.S.; requiring an affected municipal electric utility to conduct a referendum election of all its retail electric customers to determine whether to require the municipal electric utility to provide a proposed charter transferring the operations of the utility to an electric utility authority; amending s. 366.81, F.S.; providing legislative intent; amending s. 366.82, F.S.; defining the term "demand-side renewable energy"; requiring the Public Service Commission to adopt goals for increasing the development of demand-side renewable energy systems energy resources; providing for cost-effectiveness tests; requiring the Florida Energy and Climate Commission to be a party in the proceedings to adopt goals; providing for an appropriations; providing for cost recovery; authorizing the commission to provide financial rewards and penalties; authorizing the commission to allow an investor-owned utility to earn an additional return on equity for exceeding energy efficiency and conservation goals; amending s. 366.8255, F.S.; redefining the term "environmental compliance costs" to include costs or expenses prudently incurred for scientific research and geological assessments of carbon capture and storage for the purpose of reducing an electric utility's greenhouse gas emissions; amending s. 366.91, F.S.; clarifying the definition of "biomass" to include waste and byproducts; requiring each public utility, and each municipal electric utility and rural electric utility cooperative that sells electricity at retail, to develop a standardized interconnection and net metering program for customer-owned renewable generation; authorizing net metering to be available when a utility purchases power generated from biogas produced by anaerobic digestion under certain conditions; amending s. 366.92, F.S.; directing the Public Service Commission to adopt a renewable portfolio standard; providing definitions; providing for renewable energy credits; providing for cost recovery; prohibiting the renewable portfolio standard rule from taking effect until ratified by the Legislature; amending s. 366.93, F.S.; revising the definitions of "cost" and "preconstruction"; requiring the Public Service Commission to establish rules relating to cost recovery for the construction of new, expanded, or relocated electrical transmission lines and facilities for a nuclear power plant; amending s. 377.601, F.S.; revising legislative intent with respect to the need to implement alternative energy technologies; providing for the transfer of the Florida Energy Commission in the Office of Legislative Services to the Florida Energy and Climate Commission in the Executive Office of the Governor; creating s. 377.6015, F.S.; providing for the membership, meetings, duties, and responsibilities of the Florida Energy and Climate Commission; providing rulemaking authority; amending s. 377.602, F.S.; revising the definition of

"energy resources"; providing for conforming changes; providing for the type two transfer of the state energy program in the Department of Environmental Protection to the Florida Energy and Climate Commission in the Executive Office of the Governor; amending ss. 377.603, 377.604, 377.605, 377.606, 377.608, 377.701, 377.703, and 377.705, F.S.; providing for conforming changes;

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amending s. 377.801, F.S.; providing a short title; amending s. 377.802, F.S.; providing the purpose of the Florida Energy and Climate Protection Act; amending s. 377.803, F.S.; revising definitions; clarifying the definition of "renewable energy" to include biomass, as defined in s. 366.91, F.S.; amending s. 377.804, F.S., relating to the Renewable Energy and Energy-Efficient Technologies Grants Program; providing for the program to include matching grants for technologies that increase the energy efficiency of vehicles and commercial buildings; providing for the solicitation of expertise of other entities; providing application requirements; amending s. 377.806, F.S.; conforming provisions relating to the Solar Energy System Incentives Program, to changes made by this act; requiring all eligible systems under the program to comply with the Florida Building Code; revising rebate eligibility requirements for solar thermal systems to include the installation of certain products by roofing contractors; creating s. 377.808, F.S.; establishing the "Florida Green Government Grants Act"; providing for grants to be awarded to local governments in the development of programs that achieve green standards; amending ss. 380.23 and 403.031, F.S.; conforming cross-references; creating s. 403.44, F.S.; creating the Florida Climate Protection Act; defining terms; requiring the Department of Environmental Protection to establish the methodologies, reporting periods, and reporting systems that must be used when major emitters report to The Climate Registry; authorizing the department to adopt rules for a cap-and-trade regulatory program to reduce greenhouse gas emissions from major emitters; providing for the content of the rule; prohibiting the rules from being adopted until after January 1, 2010, and from becoming effective until ratified by the Legislature; amending s. 403.502, F.S.; providing legislative intent; amending s. 403.503, F.S.; defining the term "alternate corridor" and redefining the term "corridor" for purposes of the Florida Electrical Power Plant Siting Act; amending s. 403.504, F.S.; requiring the Department of Environmental Protection to determine whether a proposed alternate corridor is acceptable; amending s. 403.506, F.S.; exempting an electric utility from obtaining certification under the Florida Electrical Power Plant Siting Act before constructing facilities for a power plant using nuclear materials as fuel; providing that a utility may obtain separate licenses, permits, and approvals for such construction under certain circumstances; exempting such provisions from review under ch. 120, F.S.; amending s. 403.5064, F.S.; requiring an applicant to submit a statement to the department if such applicant opts for consideration of alternate corridors; amending s. 403.5065, F.S.; providing for conforming changes; amending

s. 403.50663, F.S.; providing for notice of meeting to the general public; amending s. 403.50665, F.S.; requiring an application to include a statement on the consistency of directly associated facilities constituting a "development"; requiring the Department of Environmental Protection to address at the certification hearing the issue of compliance with land use plans and zoning ordinances for a proposed substation located in or along an alternate corridor; amending

s. 403.507, F.S.; providing for reports to be submitted to the department no later than 100 days after certification application has been

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determined complete; amending s. 403.508, F.S.; providing for land use and certification hearings; amending s. 403.509, F.S.; requiring the Governor and Cabinet sitting as the siting board to certify the corridor having the least adverse impact; authorizing the board to deny certification or allow a party to amend its proposal; amending

s. 403.511, F.S.; providing for conforming changes; amending s. 403.5112, F.S.; providing for filing of notice; amending s. 403.5113, F.S.; providing for postcertification amendments and postcertification review; amending s. 403.5115, F.S.; requiring the applicant proposing the alternate corridor to publish all notices relating to the application; requiring that such notices comply with certain requirements; requiring that notices be published at least 45 days before the rescheduled certification hearing; requiring applicants to make specified efforts to provide notice to certain landowners and to file a list of such notification with the Department of Environmental Protection's Siting Coordination Office; amending ss. 403.516, 403.517, and 403.5175, F.S.; providing conforming changes and cross-references; amending s. 403.518, F.S.; authorizing the Department of Environmental Protection to charge an application fee for an alternate corridor; amending ss. 403.519, 403.5252, 403.526, 403.527, 403.5271, 403.5272, 403.5312, 403.5363, 403.5365, and 403.814, F.S., relating to determinations of need, public notice requirements, and general permits; conforming provisions to changes made by the act; creating s. 403.7055, F.S.; encouraging counties in the state to form regional solutions to the capture and reuse or sale of methane gas from landfills and wastewater treatment facilities; requiring the Department of Environmental Protection to provide guidelines and assistance; amending s. 489.145, F.S.; creating s. 403.7032, F.S.; providing legislative findings regarding recycling; providing for a long-term goal of reducing the amount of solid waste disposed of in the state by a certain percentage; requiring the Department of Environmental Protection to develop a comprehensive recycling program and submit such program to the Legislature by a specified date; requiring the Legislature's approval before implementing such program; requiring that such program be developed in coordination with other state and local entities, private businesses, and the public; requiring that the program contain certain components; creating s. 403.7033, F.S., requiring a departmental analysis of particular recyclable materials; requiring a submission of a report; amending s. 403.706, F.S., requiring every county to implement a composting plan to attain certain goals by a date certain; provides for goal modifications upon demonstrated need to the department; amending s. 489.145, F.S.; revising provisions of the Guaranteed Energy, Water, and Wastewater Performance Savings Contracting Act; requiring that each proposed contract or lease contain certain agreements concerning operational cost-saving measures; requiring the Office of the Chief Financial Officer to review contract proposals; redefining terms; requiring that certain baseline information, supporting information, and documentation be included in contracts; requiring the Office of the Chief Financial Officer to review contract proposals; providing audit requirements; requiring contract approval by the Chief Financial Officer; amending

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s. 526.06, F.S.; revising provisions for the sale of gasoline blended with ethanol; providing specifications for transitioning to ethanol-blended fuels; creating s. 526.201, F.S.; creating the "Florida Renewable Fuel Standard Act"; creating s. 526.202, F.S.; establishing legislative findings for the act; creating s. 526.203, F.S.; providing definitions, fuel standard, exemptions, and reporting; creating s. 526.204, F.S.; providing for waivers; providing for suspension of standard requirement during declared emergencies; creating s. 526.205, F.S.; providing for enforcement of the act; providing for extensions; creating s. 526.206, F.S.; providing for rulemaking authority by the Department of Revenue and the Department of Agriculture and Consumer Services; creating s. 526.207, F.S.; requiring studies and reports by the Florida Energy and Climate Commission; amending s. 553.73, F.S.; requiring that the Florida Building Commission select the most recent International Energy Conservation Code as a foundation code; providing for modification of the International Energy Conservation Code by the commission under certain circumstances; creating s. 553.9061, F.S.; requiring the Florida Building Commission to establish a schedule of increases in the energy performance of buildings subject to the Florida Energy Efficiency Code for Building Construction; providing energy-efficiency performance options and elements for achieving performance goals; requiring the commission to adopt rules and implement a cost-effectiveness

test; amending s. 553.909, F.S.; requiring the Florida Energy Efficiency Code for Building Construction to set minimum requirements for certain commercial or residential appliances; requiring the Agency for Enterprise Information Technology to define specified objective standards and conduct evaluations relating to energy efficiency; requiring the agency to submit a report; providing report requirements; requiring the agency to submit specified recommendations; providing for the inclusion of specifications in certain plans and processes; creating s. 1004.648, F.S.; establishing the Florida Energy Systems Consortium consisting of all the state universities; providing for membership and duties of the consortium; providing for a director, an oversight board, and a steering committee; requiring the consortium to submit an annual report; requiring an economic impact analysis on the effects of granting financial incentives to energy producers who use woody biomass as fuel; providing that certain vehicle emission standards are subject to ratification by the Legislature prior to implementation or modification by the Department of Environmental Protection; requiring the Department of Education and the Department of Environmental Protection to develop an awards or recognition program for outstanding efforts in conservation, energy and water use reduction, environmental enhancement, and conservation-related educational curriculum development; encouraging the departments to seek private sector funding for the program; repealing s. 377.901, F.S., relating to the Florida Energy Commission; requiring the Public Service Commission to provide a report to the Governor and the Legislature on utility revenue decoupling; providing effective dates.

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10. Permits required for the taking of marine mammals under the Marine Mammal Protection Act of 1972, as amended, 16 U.S.C. s. 1374.

Section 64. Subsection (20) of section 403.031, Florida Statutes, is amended to read:

403.031 Definitions.—In construing this chapter, or rules and regulations adopted pursuant hereto, the following words, phrases, or terms, unless the context otherwise indicates, have the following meanings:

(20) "Electrical power plant" means, for purposes of this part of this chapter, any electrical generating facility that uses any process or fuel and that is owned or operated by an electric utility, as defined in s. 403.503(14)~~(13)~~, and includes any associated facility that directly supports the operation of the electrical power plant.

Section 65. Section 403.44, Florida Statutes, is created to read:

403.44 Florida Climate Protection Act.—

(1) The Legislature finds it is in the best interest of the state to document, to the greatest extent practicable, greenhouse gas emissions and to pursue a market-based emissions abatement program, such as cap and trade, to address greenhouse gas emissions reductions.

(2) As used in this section, the term:

(a) "Allowance" means a credit issued by the department through allotments or auction which represents an authorization to emit specific amounts of greenhouse gases, as further defined in department rule.

(b) "Cap and trade" or "emissions trading" means an administrative approach used to control pollution by providing a limit on total allowable emissions, providing for allowances to emit pollutants, and providing for the transfer of the allowances among pollutant sources as a means of compliance with emission limits.

(c) "Greenhouse gas" or "GHG" means carbon dioxide, methane, nitrous oxide, and fluorinated gases such as hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

(d) "Leakage" means the offset of emission abatement that is achieved in one location subject to emission control regulation by increased emissions in unregulated locations.

(e) "Major emitter" means an electric utility regulated under this chapter.

(3) A major emitter shall be required to use The Climate Registry for purposes of emission registration and reporting.

(4) The department shall establish the methodologies, reporting periods, and reporting systems that shall be used when major emitters report to The Climate Registry. The department may require the use of quality-assured data from continuous emissions monitoring systems.

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(5) The department may adopt rules for a cap-and-trade regulatory program to reduce greenhouse gas emissions from major emitters. When developing the rules, the department shall consult with the Florida Energy and Climate Commission and the Florida Public Service Commission and may consult with the Governor's Action Team for Energy and Climate Change. The department shall not adopt rules until after January 1, 2010. The rules shall not become effective until ratified by the Legislature.

(6) The rules of the cap-and-trade regulatory program shall include, but are not limited to:

(a) A statewide limit or cap on the amount of greenhouse gases emitted by major emitters.

(b) Methods, requirements, and conditions for allocating the cap among major emitters.

(c) Methods, requirements, and conditions for emissions allowances and the process for issuing emissions allowances.

(d) The relationship between allowances and the specific amounts of greenhouse gas emissions they represent.

(e) The length of allowance periods and the time over which entities must account for emissions and surrender allowances equal to emissions.

(f) The timeline of allowances from the initiation of the program through to 2050.

(g) A process for the trade of allowances between major emitters, including a registry, tracking, or accounting system for such trades.

(h) Cost containment mechanisms to reduce price and cost risks associated with the electric generation market in this state. Cost containment mechanisms to be considered for inclusion in the rules include, but are not limited to:

1. Allowing major emitters to borrow allowances from future time periods to meet their greenhouse gas emission limits.

2. Allowing major emitters to bank greenhouse gas emission reductions in the current year to be used to meet emission limits in future years.

3. Allowing major emitters to purchase emissions offsets from other entities that produce verifiable reductions in unregulated greenhouse gas emissions or that produce verifiable reductions in greenhouse gas emissions through voluntary practices that capture and store greenhouse gases that otherwise would be released into the atmosphere. In considering this cost containment mechanism, the department shall identify sectors and activities outside of the capped sectors, including other state, federal, or international activities, and the conditions under which reductions there can be credited against emissions of capped entities in place of allowances issued by the department. The department shall also consider potential methods and their effectiveness to avoid double-incentivizing such activities.

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4. Providing a safety valve mechanism to ensure that the market prices for allowances or offsets do not surpass a predetermined level compatible with the affordability of electric utility rates and

the well-being of the state's economy. In considering this cost containment mechanism, the department shall evaluate different price levels for the safety valve and methods to change the price level over time to reflect changing state, federal, and international markets, regulatory environments, and technological advancements.

In considering cost containment mechanisms for inclusion in the rules, the department shall evaluate the anticipated overall effect of each mechanism on the abatement of greenhouse gas emissions and on electricity ratepayers and the benefits and costs of each to the state's economy, and shall also consider the interrelationships between the mechanisms under consideration.

□ (i) A process to allow the department to exercise its authority to discourage leakage of GHG emissions to neighboring states attributable to the implementation of this program.
□ (j) Provisions for a trial period on the trading of allowances before full implementation of a trading system.
□ (7) In recommending and evaluating proposed features of the cap-andtrade system, the following factors shall be considered:
□ (a) The overall cost-effectiveness of the cap-and-trade system in combination with other policies and measures in meeting statewide targets.
□ (b) Minimizing the administrative burden to the state of implementing, monitoring, and enforcing the program.
(c) Minimizing the administrative burden on entities covered under the cap.
(d) The impacts on electricity prices for consumers.
□ (e) The specific benefits to the state's economy for early adoption of a cap-and-trade system for greenhouse gases in the context of federal climate change legislation and the development of new international compacts.
□ (f) The specific benefits to the state's economy associated with the creation and sale of emissions offsets from economic sectors outside of the emissions cap.
□ (g) The potential effects on leakage if economic activity relocates out of the state.
□ (h) The effectiveness of the combination of measures in meeting identified targets.
□ (i) The implications for near-term periods of long-term targets specified in the overall policy.

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□ (j) The overall costs and benefits of a cap-and-trade system to the state economy.
□ (k) How to moderate impacts on low-income consumers that result from energy price increases.
□ (l) Consistency of the program with other state and possible federal efforts.
□ (m) The feasibility and cost-effectiveness of extending the program scope as broadly as possible among emitting activities and sinks in Florida.
□ (n) Evaluation of the conditions under which Florida should consider linking its trading system to the systems of other states or other countries and how that might be affected by the potential inclusion in the rule of a safety valve.
□ (8) Recognizing that the international, national, and neighboring state policies and the science of climate change will evolve, prior to submitting the proposed rules to the Legislature for consideration, the department shall submit the proposed rules to the Florida Energy and Climate Commission, which shall review the proposed rules and submit a report to the Governor, the President of the Senate, the Speaker of the House of Representatives, and the department. The report shall address:
□ (a) The overall cost-effectiveness of the proposed cap-and-trade system in combination with other policies and measures in meeting statewide targets.
□ (b) The administrative burden to the state of implementing, monitoring, and enforcing the program.

□ (c) The administrative burden on entities covered under the cap.
□ (d) The impacts on electricity prices for consumers.
□ (e) The specific benefits to the state's economy for early adoption of a cap-and-trade system for greenhouse gases in the context of federal climate change legislation and the development of new international compacts.
□ (f) The specific benefits to the state's economy associated with the creation and sale of emissions offsets from economic sectors outside of the emissions cap.
□ (g) The potential effects on leakage if economic activity relocates out of the state.
□ (h) The effectiveness of the combination of measures in meeting identified targets.
□ (i) The economic implications for near-term periods of short-term and long-term targets specified in the overall policy.
□ (j) The overall costs and benefits of a cap-and-trade system to the economy of the state.

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□ (k) The impacts on low-income consumers that result from energy price increases.
□ (l) The consistency of the program with other state and possible federal efforts.
□ (m) The evaluation of the conditions under which the state should consider linking its trading system to the systems of other states or other countries and how that might be affected by the potential inclusion in the rule of a safety valve.
□ (n) The timing and changes in the external environment, such as proposals by other states or implementation of a federal program that would spur reevaluation of the Florida program.
□ (o) The conditions and options for eliminating the Florida program if a federal program were to supplant it.
□ (p) The need for a regular reevaluation of the progress of other emitting regions of the country and of the world, and whether other regions are abating emissions in a commensurate manner.
□ (q) The desirability of and possibilities of broadening the scope of the state's cap-and-trade system at a later date to include more emitting activities as well as sinks in Florida, the conditions that would need to be met to do so, and how the program would encourage these conditions to be met, including developing monitoring and measuring techniques for land use emissions and sinks, regulating sources upstream, and other considerations.

Section 66. Section 403.502, Florida Statutes, is amended to read:

403.502 Legislative intent.—The Legislature finds that the present and predicted growth in electric power demands in this state requires the development of a procedure for the selection and utilization of sites for electrical generating facilities and the identification of a state position with respect to each proposed site and its associated facilities. The Legislature recognizes that the selection of sites and the routing of associated facilities, including transmission lines, will have a significant impact upon the welfare of the population, the location and growth of industry, and the use of the natural resources of the state. The Legislature finds that the efficiency of the permit application and review process at both the state and local level would be improved with the implementation of a process whereby a permit application would be centrally coordinated and all permit decisions could be reviewed on the basis of standards and recommendations of the deciding agencies. It is the policy of this state that, while recognizing the pressing need for increased power generation facilities, the state shall ensure through available and reasonable methods that the location and operation of electrical power plants will produce minimal adverse effects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic life and will not unduly conflict with the goals established by the applicable local comprehensive plans. It is the intent to seek courses of action that will fully balance the increasing

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MARTIN SOLAR PROJECT

MILESTONES

Milestone	Date
Award engineering contracts	August, 2008
Select mirror and heat collection element suppliers	November, 2008
Receive Site Certification modification and ACOE Dredge Permit modification	September, 2008
2008/2009 ECRC approval	November 6, 2008
Select solar collection and steam generator suppliers	December, 2008
Initial site mobilization	December, 2008
Start construction	January, 2009
Commercial operation	December, 2010

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 9
COMPANY Florida Power & Light Co. (Direct)
WITNESS E. Silagy (ES-1)
DATE 11-04-08

DESOTO SOLAR PROJECT

MILESTONES

Milestone	Date
Award EPC Contract	July, 2008
Design Engineering Complete	October, 2008
2008/2009 ECRC Approval	November 6, 2008
Receive approvals necessary to begin construction	December, 2008
Site Mobilization/ Start Construction	January, 2009
Commence Testing	July, 2009
Commercial Operation All Phases (25 MW)	December, 2009

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 10
COMPANY Florida Power & Light Co. (Direct)
WITNESS E. Silagy (ES-2)
DATE 11-04-08

SPACE COAST SOLAR PROJECT

MILESTONES

Milestone	Date
Award EPC Contract	July, 2008
Design Engineering Complete	July, 2009
2008/2009 ECRC Approval	November 6, 2008
Receive approvals necessary to begin construction	February, 2009
Site Mobilization/ Start Construction	September, 2009
Commence Testing	May, 2010
Commercial Operation All Phases (10 MW)	July, 2010

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 11
COMPANY Florida Power & Light Co. (Direct)
WITNESS E. Silagy (ES-3)
DATE 11-04-08

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)

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

JANUARY 2007 - DECEMBER 2007
FINAL TRUE-UP
DOCKET NO. 080007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 12
COMPANY PEF, Inc. (Direct)
WITNESS Will Garrett (WG-1)
DATE 11-04-08

PROGRESS ENERGY FLORIDA

Form 42-1A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2007 through December 2007 (Form 42-2A, Line 5 + 6 + 10)	$ 2,219,585
2	Estimated/Actual True-Up Amount approved for the period January 2007 through December 2007 (Order No. PSC-07-0922-FOF-EI)	(3,333,530)
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2009 to December 2009 (Lines 1 - 2)	**$ 5,553,115**

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-1)
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Form 42-2A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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

Line	Description		Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$3,589,145	$3,791,302	$3,628,304	$3,662,405	$3,938,399	$4,420,670	$4,966,287	$5,739,169	$5,247,951	$4,811,852	$4,168,469	$3,631,366	$51,595,321
2	True-Up Provision	($17,007,816)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(17,007,816)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		2,171,827	2,373,984	2,210,986	2,245,087	2,521,081	3,003,352	3,548,969	4,321,851	3,830,633	3,394,534	2,751,151	2,214,048	34,587,505
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		1,291,085	3,157,215	2,405,128	2,509,070	3,324,031	3,548,168	2,832,678	3,241,242	2,707,579	3,588,078	2,965,741	(1,838,540)	29,731,475
	b. Capital Investment Projects (Form 42-7A, Line 9)		76,435	145,258	157,483	177,326	164,044	169,455	182,546	174,463	181,519	171,156	264,029	401,265	2,264,979
	c. Total Jurisdictional ECRC Costs		1,367,520	3,302,473	2,562,611	2,686,396	3,488,075	3,717,623	3,015,224	3,415,705	2,889,098	3,759,234	3,229,770	(1,437,275)	31,996,454
5	Over/(Under) Recovery (Line 3 - Line 4c)		804,307	(928,489)	(351,625)	(441,308)	(966,994)	(714,271)	533,746	906,146	941,535	(364,700)	(478,620)	3,651,324	2,591,051
6	Interest Provision (Form 42-3A, Line 10)		(59,047)	(53,235)	(50,064)	(45,812)	(42,889)	(40,643)	(34,916)	(26,588)	(15,819)	(7,590)	(3,463)	8,600	(371,466)
7	Beginning Balance True-Up & Interest Provision		(17,007,816)	(14,845,238)	(14,409,644)	(13,394,015)	(12,463,817)	(12,056,383)	(11,393,979)	(9,477,831)	(7,180,954)	(4,837,920)	(3,792,893)	(2,857,657)	(17,007,816)
	a. Deferred True-Up from January 2006 to December 2006 (Order No. PSC-06-0972-FOF-EI)		2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714
8	True-Up Collected/(Refunded) (see Line 2)		1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	17,007,816
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		(12,398,524)	(11,962,930)	(10,947,301)	(10,017,103)	(9,609,669)	(8,947,265)	(7,031,117)	(4,734,240)	(2,391,206)	(1,346,179)	(410,943)	4,675,901	4,675,901
10	Adjustments to Period Total True-Up Including Interest (a)		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Lines 9 + 10)		($12,398,524)	($11,962,930)	($10,947,301)	($10,017,103)	($9,609,669)	($8,947,265)	($7,031,117)	($4,734,240)	($2,391,206)	($1,346,179)	($410,943)	$4,675,901	$4,675,901

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. ___(WG-1)
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Form 42-3A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Interest Provision
(in Dollars)

Line	Description	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	**($14,561,102)**	($12,398,524)	($11,962,930)	($10,947,301)	($10,017,103)	($9,609,669)	($8,947,265)	($7,031,117)	($4,734,240)	($2,391,206)	($1,346,179)	($410,943)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	(12,339,477)	(11,909,695)	(10,897,237)	(9,971,291)	(9,566,780)	(8,906,622)	(6,996,201)	(4,707,652)	(2,375,387)	(1,338,589)	(407,480)	4,657,699	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	(26,900,579)	(24,308,219)	(22,860,167)	(20,918,593)	(19,583,883)	(18,516,290)	(15,943,465)	(11,738,769)	(7,109,628)	(3,729,795)	(1,753,659)	4,246,756	
4	Average True-Up Amount (Line 3 x 1/2)	(13,450,290)	(12,154,110)	(11,430,084)	(10,459,297)	(9,791,942)	(9,258,145)	(7,971,733)	(5,869,385)	(3,554,814)	(1,864,898)	(876,830)	2,123,378	
5	Interest Rate (First Day of Reporting Business Month)	5.27%	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.24%	5.62%	5.05%	4.72%	4.75%	
6	Interest Rate (First Day of Subsequent Business Month)	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.24%	5.62%	5.05%	4.72%	4.75%	4.98%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53%	10.52%	10.52%	10.52%	10.52%	10.54%	10.52%	10.86%	10.67%	9.77%	9.47%	9.73%	
8	Average Interest Rate (Line 7 x 1/2)	5.265%	5.260%	5.260%	5.260%	5.260%	5.270%	5.260%	5.430%	5.335%	4.885%	4.735%	4.865%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.439%	0.438%	0.438%	0.438%	0.438%	0.439%	0.438%	0.453%	0.445%	0.407%	0.395%	0.405%	
10	Interest Provision for the Month (Line 4 x Line 9)	($59,047)	($53,235)	($50,064)	($45,812)	($42,889)	($40,643)	($34,916)	($26,588)	($15,819)	($7,590)	($3,463)	$8,600	**($371,466)**

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-1)
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PROGRESS ENERGY FLORIDA

Form 42-4A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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	$2,852,542	$2,652,554	$199,988	7.5%
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	3,663,044	3,971,507	(308,463)	-7.8%
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	16,067,508	17,001,677	(934,169)	-5.5%
	3a Pipeline Integrity Management	449,790	788,427	(338,637)	-43.0%
	4 Above Ground Tank Secondary Containment	810	540	270	50.0%
	5 SO2 Emissions Allowances	4,242,943	9,047,737	(4,804,794)	-53.1%
	6 Phase II Cooling Water Intake	556,141	477,858	78,283	16.4%
	8 Arsenic Groundwater Standard - Base	0	8,053	(8,053)	-100.0%
	9 Sea Turtle - Coastal Street Lighting - Distrib	25,158	122,558	(97,400)	-79.5%
	11 Modular Cooling Towers - Base	3,318,462	3,318,462	(0)	0.0%
2	Total O&M Activities - Recoverable Costs	$31,176,397	$37,389,373	($6,212,976)	-16.6%
3	Recoverable Costs Allocated to Energy	4,242,943	9,047,737	(4,804,794)	-53.1%
4	Recoverable Costs Allocated to Demand	26,933,453	28,341,636	(1,408,183)	-5.0%

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)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Form 42-5A

O&M Activities
(in Dollars)

Line	Description	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Description of O&M Activities													
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$239,677	$404,052	$186,759	$67,204	$200,747	$415,202	$430,341	$135,101	$167,210	$59,086	$156,248	$390,916	$2,852,542
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	204,636	287,009	347,827	249,279	731,100	55,969	56,301	130,616	194,330	382,326	393,193	630,458	3,663,044
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	209,427	1,850,001	1,281,512	1,577,149	1,678,820	1,044,151	730,673	1,185,880	1,372,098	2,283,419	1,808,847	1,045,529	16,067,508
3a	Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	28,552	7,972	17,666	20,449	17,513	14,275	9,750	12,312	93,746	95,993	(40,171)	171,733	449,790
4	Above Ground Tank Secondary Containment - Intm	0	0	0	0	540	0	0	0	0	0	0	270	810
5	SO2 Emissions Allowances	679,649	686,895	647,751	554,484	747,975	870,997	860,255	969,953	858,299	833,343	711,544	(4,178,199)	4,242,943
6	Phase II Cooling Water Intake 316(b) - Base	0	12,500	0	54,096	0	564	21,278	7,500	7,138	6,880	13,114	12,792	135,862
6a	Phase II Cooling Water Intake 316(b) - Intm	58,231	76,707	10,985	43,650	34,105	28,520	28,061	18,133	16,265	15,303	2,067	88,251	420,279
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	646	4,675	15,400	1,837	1,715	4,144	74	(3,335)	0	0	25,158
11a	Modular Cooling Towers - Base	(18,290)	0	0	0	0	1,370,452	923,565	923,565	119,170	0	0	0	3,318,462
2	Total of O&M Activities	1,401,881	3,325,136	2,493,146	2,570,986	3,426,199	3,801,967	3,061,941	3,387,204	2,828,330	3,673,015	3,044,842	(1,838,251)	$31,176,397
3	Recoverable Costs Allocated to Energy	679,649	686,895	647,751	554,484	747,975	870,997	860,255	969,953	858,299	833,343	711,544	(4,178,199)	4,242,943
4	Recoverable Costs Allocated to Demand - Transm	239,677	404,052	186,759	67,204	200,747	415,202	430,341	135,101	167,210	59,086	156,248	390,916	2,852,542
	Recoverable Costs Allocated to Demand - Distrib	414,063	2,137,011	1,629,986	1,831,103	2,425,320	1,101,957	788,690	1,320,640	1,566,503	2,662,410	2,202,040	1,675,987	19,755,709
	Recoverable Costs Allocated to Demand - Prod-Base	(18,290)	12,500	0	54,096	0	1,371,016	944,844	931,065	126,307	6,880	13,114	12,792	3,454,324
	Recoverable Costs Allocated to Demand - Prod-Intm	86,783	84,679	28,651	64,099	52,158	42,795	37,812	30,445	110,012	111,296	(38,104)	260,255	870,879
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Retail Energy Jurisdictional Factor	0.96820	0.96800	0.96830	0.96760	0.97000	0.96250	0.96210	0.96250	0.96000	0.96030	0.95580	0.95770	
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	
7	Jurisdictional Energy Recoverable Costs (A)	658,036	664,914	627,217	536,518	725,535	838,335	827,651	933,580	823,967	800,259	680,094	(4,001,461)	4,114,645
8	Jurisdictional Demand Recoverable Costs - Transm (B)	169,205	285,248	131,846	47,444	141,721	293,120	303,808	95,377	118,045	41,713	110,306	275,975	2,013,808
	Jurisdictional Demand Recoverable Costs - Distrib (B)	412,394	2,128,398	1,623,417	1,823,724	2,415,546	1,097,516	785,511	1,315,318	1,560,190	2,651,681	2,193,166	1,669,233	19,676,094
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	(17,148)	11,719	0	50,717	0	1,285,369	885,819	872,902	118,417	6,450	12,295	11,992	3,238,532
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	68,598	66,936	22,648	50,667	41,229	33,828	29,889	24,065	86,960	87,975	(30,120)	205,721	688,396
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,291,085	$3,157,215	$2,405,128	$2,509,070	$3,324,031	$3,548,168	$2,832,678	$3,241,242	$2,707,579	$3,586,078	$2,965,741	($1,838,540)	$29,731,475

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

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-1)
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PROGRESS ENERGY FLORIDA

Form 42-6A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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				
3b	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$407,424	$408,288	($864)	-0.2%
4.x	Above Ground Tank Secondary Containment	656,663	632,425	24,238	3.8%
5	SO2 Emissions Allowances	1,015,996	656,912	359,084	54.7%
7.x	CAIR/CAMR	180,003	184,493	(4,490)	-2.4%
9	Sea Turtle - Coastal Street Lighting -Distribution	532	950	(418)	-44.0%
10.x	Underground Storage Tanks-Base	42,270	42,029	241	0.6%
11	Modular Cooling Towers - Base	197,936	198,074	(138)	-0.1%
2	Total Capital Investment Activities - Recoverable Costs	2,500,824	2,123,171	$377,653	17.8%
3	Recoverable Costs Allocated to Energy	1,015,996	656,912	$359,084	54.7%
4	Recoverable Costs Allocated to Demand	$1,484,828	$1,466,259	$18,569	1.3%

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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Form 42-7A

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Description of Investment Projects (A)													
	3b Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$9,860	$36,410	$36,335	$36,259	$36,219	$36,178	$36,114	$36,059	$36,062	$36,053	$35,973	$35,902	$407,424
	4.1 Above Ground Tank Secondary Containment - Peaking	40,390	35,600	47,337	60,123	47,257	51,635	51,172	52,205	65,230	60,490	59,013	60,970	631,422
	4.2 Above Ground Tank Secondary Containment - Base	486	468	467	466	465	463	462	461	460	459	457	456	5,570
	4.3 Above Ground Tank Secondary Containment - Intermediate	0	0	0	0	0	0	0	1,044	3,221	5,001	5,210	5,195	19,671
	5 SO2/NOX Emissions Allowances - Energy	10,427	63,038	62,924	70,260	66,617	66,044	71,373	66,282	58,457	49,654	145,465	285,455	1,015,996
	7.1 CAIR/CAMR - Intermediate	598	598	598	599	604	607	607	607	607	614	633	676	7,348
	7.2 CAIR/CAMR - Peaking	5,671	6,198	7,870	9,408	11,643	14,562	15,764	16,488	17,232	17,893	21,501	24,661	168,891
	7.3 CAIR/CAMR - Base	0	0	0	0	0	0	0	2,417	323	323	333	368	3,764
	9 Sea Turtle - Coastal Street Lighting -Distribution	0	0	0	0	0	33	66	66	66	87	107	107	532
	10.1 Underground Storage Tanks-Base	2,394	2,397	2,400	2,400	2,129	1,858	3,005	2,539	2,534	2,528	2,523	2,518	29,225
	10.2 Underground Storage Tanks-Intermediate	1,069	1,083	1,066	1,066	947	1,328	1,086	1,084	1,082	1,080	1,078	1,076	13,045
	11 Modular Cooling Towers - Base	14,445	15,200	15,687	15,797	15,710	15,627	22,525	14,650	17,561	17,865	17,317	15,552	197,936
2	Total Investment Projects - Recoverable Costs	85,340	160,992	174,684	196,378	181,591	188,335	202,174	193,902	202,835	192,047	289,610	432,936	2,500,824
3	Recoverable Costs Allocated to Energy	10,427	63,038	62,924	70,260	66,617	66,044	71,373	66,282	58,457	49,654	145,465	285,455	1,015,996
	Recoverable Costs Allocated to Demand	0	0	0	0	0	33	66	66	66	87	107	107	532
4	Recoverable Costs Allocated to Demand - Production - Base	17,325	18,065	18,554	18,663	18,304	17,948	25,992	20,067	20,878	21,175	20,630	18,894	236,495
	Recoverable Costs Allocated to Demand - Production - Intermediate	11,527	38,091	37,999	37,924	37,770	38,113	37,807	38,794	40,972	42,748	42,894	42,849	447,488
	Recoverable Costs Allocated to Demand - Production - Peaking	46,061	41,798	55,207	69,531	58,900	66,197	66,936	68,693	82,462	78,383	80,514	85,631	800,313
5	Retail Energy Jurisdictional Factor	0.96820	0.96800	0.96830	0.96760	0.97000	0.96250	0.96210	0.96250	0.96000	0.96030	0.95580	0.95770	
	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)	10,096	61,021	60,929	67,983	64,619	63,567	68,668	63,797	56,119	47,683	139,035	273,381	976,896
	Jurisdictional Demand Recoverable Costs (B)	0	0	0	0	0	33	66	66	66	87	107	107	530
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	16,243	16,936	17,395	17,497	17,161	16,827	24,368	18,813	19,574	19,852	19,341	17,714	221,721
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	9,112	30,109	30,037	29,977	29,856	30,127	29,885	30,665	32,387	33,791	33,906	33,870	353,721
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	40,985	37,191	49,123	61,868	52,409	58,901	59,559	61,122	73,374	69,744	71,641	76,194	712,111
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$76,435	$145,258	$157,483	$177,326	$164,044	$169,455	$182,546	$174,463	$181,519	$171,156	$264,029	$401,265	$2,264,979

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

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Progress Energy Florida
Witness: Will Garrett
Exhibit No. ___ (WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$6,259	$0	$2,135	$1,441	$12,866	($824)	$0	$808	$22,685
	b. Clearings to Plant		0	0	0	0	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	$2,674,588	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	2,674,588	
3	Less: Accumulated Depreciation	($172,057)	(178,899)	(185,742)	(192,584)	(199,427)	(206,269)	(213,112)	(219,954)	(226,797)	(233,639)	(240,482)	(247,324)	(254,167)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	6,259	6,259	8,394	9,835	22,701	21,877	21,877	22,685	
5	Net Investment (Lines 2 + 3 + 4)	2,502,531	2,495,688	2,488,846	2,482,004	2,475,161	2,474,578	2,467,735	2,463,028	2,457,626	2,463,650	2,455,983	2,449,141	2,443,106	
6	Average Net Investment		2,499,110	2,492,267	2,485,425	2,478,582	2,474,869	2,471,157	2,465,382	2,460,327	2,460,638	2,459,817	2,452,562	2,446,124	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		23,242	23,178	23,114	23,051	23,016	22,982	22,928	22,881	22,884	22,876	22,809	22,749	$275,710
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		4,248	4,237	4,225	4,214	4,207	4,201	4,191	4,183	4,183	4,182	4,169	4,158	50,399
8	Investment Expenses														
	a. Depreciation (C) 3.07%		6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	82,110
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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)		(24,473)	2,152	2,152	2,152	2,152	2,152	2,152	2,152	2,152	2,152	2,152	2,152	(795)
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		9,860	36,410	36,335	36,259	36,219	36,178	36,114	36,059	36,062	36,053	35,973	35,902	407,424
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		9,860	36,410	36,335	36,259	36,219	36,178	36,114	36,059	36,062	36,053	35,973	35,902	407,424
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)		7,794	28,781	28,721	28,661	28,630	28,597	28,547	28,503	28,506	28,498	28,435	28,379	322,052
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,794	$28,781	$28,721	$28,661	$28,630	$28,597	$28,547	$28,503	$28,506	$28,498	$28,435	$28,379	$322,052

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) 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 2005 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$4,822	$232,073	$72,119	$65,056	$511,575	$102,207	($29,321)	$231,426	($10,666)	$152,437	$114,702	$265,778	$1,712,209
	b. Clearings to Plant		0	0	251,899	2,984	0	97,710	0	0	1,004,521	82,450	297	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	
			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$474,071	474,071	474,071	2,340,200	2,343,184	2,343,184	2,440,894	2,440,894	2,440,894	3,445,415	3,527,865	3,528,162	3,525,178	
3	Less: Accumulated Depreciation	(31,519)	(33,333)	(35,072)	(57,610)	(64,474)	(71,338)	(78,963)	(86,044)	(93,124)	(109,115)	(121,352)	(131,340)	(141,321)	
4	CWIP - Non-Interest Bearing	2,473,260	2,478,082	2,710,155	916,146	978,218	1,489,793	1,494,290	1,464,969	1,696,395	681,208	751,195	865,600	1,131,378	
5	Net Investment (Lines 2 + 3 + 4)	$2,915,812	2,918,820	3,149,155	3,198,736	3,256,928	3,761,640	3,856,222	3,819,819	4,044,165	4,017,508	4,157,708	4,262,422	4,515,235	
6	Average Net Investment		2,917,316	3,033,988	3,165,965	3,227,832	3,509,284	3,808,657	3,838,022	3,931,993	4,030,837	4,087,608	4,210,064	4,388,829	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		34,547	28,216	29,232	30,019	32,636	35,421	35,694	36,568	37,487	38,015	39,154	40,816	$417,804
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		6,314	5,158	5,344	5,487	5,966	6,475	6,525	6,684	6,852	6,949	7,157	7,461	76,373
8	Investment Expenses														
	a. Depreciation (C)		1,814	1,739	6,578	22,824	6,864	7,627	7,081	7,081	15,991	12,237	9,988	9,981	109,803
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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)		(2,285)	488	6,182	1,793	1,793	2,114	1,873	1,873	4,901	3,289	2,714	2,712	27,446
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		40,390	35,600	47,337	60,123	47,257	51,635	51,172	52,205	65,230	60,490	59,013	60,970	631,422
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		40,390	35,600	47,337	60,123	47,257	51,635	51,172	52,205	65,230	60,490	59,013	60,970	631,422
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (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)		35,939	31,677	42,120	53,497	42,049	45,944	45,532	46,451	58,041	53,823	52,509	54,250	561,833
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$35,939	$31,677	$42,120	$53,497	$42,049	$45,944	$45,532	$46,451	$58,041	$53,823	$52,509	$54,250	$561,833

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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	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 (B)		$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 (C)		(4,549)	(4,661)	(4,772)	(4,883)	(4,994)	(5,105)	(5,216)	(5,327)	(5,439)	(5,550)	(5,661)	(5,772)	(5,883)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$28,543	28,431	28,320	28,209	28,098	27,987	27,876	27,765	27,653	27,542	27,431	27,320	27,209	
6	Average Net Investment			28,487	28,376	28,265	28,154	28,042	27,931	27,820	27,709	27,598	27,487	27,376	27,264	$0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		265	264	263	262	261	260	259	258	257	256	255	254	3,111
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		48	48	48	48	48	47	47	47	47	47	47	46	569
8	Investment Expenses															
	a. Depreciation (C)			111	111	111	111	111	111	111	111	111	111	111	111	1,334
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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)			61	45	45	45	45	45	45	45	45	45	45	45	557
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			486	468	467	466	465	463	462	461	460	459	457	456	5,570
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			486	468	467	466	465	463	462	461	460	459	457	456	5,570
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)			456	439	438	437	436	434	433	432	431	430	428	428	5,222
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$456	$439	$438	$437	$436	$434	$433	$432	$431	$430	$428	$428	$5,222

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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$189,743	$33,541	$66,766	$247	$0	$290,297
	b. Clearings to Plant			0	0	0	0	0	0	0	0	223,284	66,766	0	247	
	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 (B)		$0	0	0	0	0	0	0	0	0	223,284	290,050	290,050	290,297	
3	Less: Accumulated Depreciation (C)		0	0	0	0	0	0	0	0	0	(627)	(2,349)	(3,978)	(5,609)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	189,743	0	0	247	0	
5	Net Investment (Lines 2+ 3 + 4)		$0	0	0	0	0	0	0	0	189,743	222,657	287,701	286,319	284,689	
6	Average Net Investment			0	0	0	0	0	0	0	94,871	206,200	255,179	287,010	285,504	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	0	0	0	0	882	1,918	2,373	2,669	2,655	10,498
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	161	351	434	488	485	1,919
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	0	0	0	0	627	1,722	1,629	1,631	5,609
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	326	472	424	424	1,645
	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	1,044	3,221	5,001	5,210	5,195	19,671
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	1,044	3,221	5,001	5,210	5,195	19,671
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)			0	0	0	0	0	0	0	825	2,546	3,953	4,118	4,106	15,549
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$825	$2,546	$3,953	$4,118	$4,106	$15,549

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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO2 Emission Allowance Inventory		$1,942,701	$11,634,783	$10,919,619	$10,243,599	$9,660,846	$8,884,602	$7,985,335	$7,096,811	$6,098,589	$5,212,021	$4,350,408	$3,610,595	$2,905,441	$2,905,441
	b. 25401FL Auctioned SO2 Allowance		($5,115,691)	(6,087,422)	(6,059,153)	(6,030,883)	(6,002,614)	(7,072,910)	(7,044,641)	(7,016,371)	(6,988,102)	(6,959,832)	(6,931,563)	(6,903,294)	(2,019,940)	(2,019,940)
	c. 1581002 NOX Emission Allowance Inventory		0	521,500	532,140	1,835,330	3,068,228	3,574,093	5,681,533	6,274,183	6,586,183	6,679,723	6,677,223	25,644,723	28,663,433	28,663,433
2	Total Working Capital		($4,172,991)	6,068,861	5,392,606	6,048,045	6,726,459	5,385,784	6,622,227	6,354,622	5,696,669	4,931,911	4,096,068	22,352,024	29,548,933	29,548,933
3	Average Net Investment			947,935	5,730,734	5,720,326	6,387,252	6,056,122	6,004,006	6,488,425	6,025,646	5,314,290	4,513,989	13,224,046	25,950,479	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		8,816	53,296	53,199	59,401	56,322	55,837	60,342	56,039	49,423	41,980	122,984	241,339	$858,978
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		1,611	9,742	9,725	10,858	10,295	10,207	11,030	10,244	9,034	7,674	22,481	44,116	157,018
5	Total Return Component (B)			10,427	63,038	62,924	70,260	66,617	66,044	71,373	66,282	58,457	49,654	145,465	285,455	1,015,996
6	Expense Dr (Cr)															
	a. 5090001 SO2 allowance expense			707,918	715,164	676,020	582,753	776,244	899,266	888,524	998,222	886,568	861,612	739,813	705,154	9,437,260
	b. 4074004 Amortization Expense			($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($4,883,353)	($5,194,317)
7	Net Expense (C)			679,649	686,895	647,751	554,484	747,975	870,997	860,255	969,953	858,299	833,343	711,544	(4,178,199)	4,242,943
8	Total System Recoverable Expenses (Lines 5 + 7)			690,076	749,933	710,674	624,743	814,592	937,041	931,628	1,036,235	916,756	882,997	857,008	(3,892,744)	5,258,939
	a. Recoverable costs allocated to Energy			690,076	749,933	710,674	624,743	814,592	937,041	931,628	1,036,235	916,756	882,997	857,008	(3,892,744)	5,258,939
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96820	0.96800	0.96830	0.96760	0.97000	0.96250	0.96210	0.96250	0.96000	0.96030	0.95580	0.95770	
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)			668,131	725,935	688,146	604,502	790,154	901,902	896,319	997,376	880,086	847,942	819,129	(3,728,081)	5,091,541
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)			$ 668,131	$ 725,935	$ 688,146	$ 604,502	$ 790,154	$ 901,902	$ 896,319	$ 997,376	$ 880,086	$ 847,942	$ 819,129	$ (3,728,081)	$ 5,091,541

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 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Intermediate (Project 7.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			($1)	$0	$0	$317	$458	$123	$0	$0	$0	$1,129	$2,414	$5,424	$9,864
	b. Clearings to Plant			0	0	0	0	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 (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		54,328	54,326	54,326	54,326	54,644	55,102	55,225	55,225	55,225	55,225	56,354	58,767	64,192	
5	Net Investment (Lines 2+ 3 + 4)		$54,328	54,326	54,326	54,326	54,644	55,102	55,225	55,225	55,225	55,225	56,354	58,767	64,192	
6	Average Net Investment			54,327	54,326	54,326	54,485	54,873	55,163	55,225	55,225	55,225	55,789	57,560	61,479	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		505	505	505	507	510	513	514	514	514	519	535	572	$6,212
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		92	92	92	93	93	94	94	94	94	95	98	105	1,136
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)			598	598	598	599	604	607	607	607	607	614	633	676	7,348
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			598	598	598	599	604	607	607	607	607	614	633	676	7,348
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)			473	473	473	473	477	480	480	480	480	485	500	534	5,808
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$473	$473	$473	$473	$477	$480	$480	$480	$480	$485	$500	$534	$5,808

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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$21,336	$74,589	$229,647	$49,978	$356,103	$174,806	$43,473	$88,188	$47,177	$73,206	$72,336	$126,892	$1,357,731
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	1,092,182	88,179	
	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	1,092,182	1,180,361	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	(1,946)	(5,914)	
4	CWIP - Non-Interest Bearing		504,830	526,165	600,755	830,401	880,380	1,236,483	1,411,290	1,454,762	1,542,950	1,590,127	1,663,333	643,487	682,200	
5	Net Investment (Lines 2 + 3 + 4)		$504,830	526,165	600,755	830,401	880,380	1,236,483	1,411,290	1,454,762	1,542,950	1,590,127	1,663,333	1,733,722	1,856,647	
6	Average Net Investment			515,499	563,460	715,577	855,391	1,058,432	1,323,888	1,433,026	1,498,856	1,566,538	1,626,729	1,698,529	1,795,186	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		4,794	5,240	6,655	7,955	9,843	12,312	13,327	13,939	14,569	15,129	15,796	16,695	$136,255
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		876	958	1,216	1,454	1,799	2,251	2,436	2,548	2,663	2,765	2,887	3,052	24,907
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	0	0	0	0	0	0	1,946	3,967	5,914
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	872	947	1,819
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,671	6,198	7,870	9,408	11,643	14,562	15,764	16,488	17,232	17,893	21,501	24,661	168,891
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			5,671	6,198	7,870	9,408	11,643	14,562	15,764	16,488	17,232	17,893	21,501	24,661	168,891
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)			5,046	5,515	7,003	8,371	10,360	12,957	14,027	14,671	15,333	15,921	19,131	21,943	150,278
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$5,046	$5,515	$7,003	$8,371	$10,360	$12,957	$14,027	$14,671	$15,333	$15,921	$19,131	$21,943	$150,278

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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR - Crystal River - Base (Project 7.3)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$8,034	$6,094	$473	$226	$0	$0	$0	$1	$0	$0	$1,823	$4,637	**$21,287**
	b. Clearings to Plant		0	0	0	0	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	**14,527**	22,561	28,655	29,128	29,353	29,353	29,353	29,353	29,355	29,355	29,355	31,178	35,814	
5	Net Investment (Lines 2 + 3 + 4)	**14,527**	22,561	28,655	29,128	29,353	29,353	29,353	29,353	29,355	29,355	29,355	31,178	35,814	
6	Average Net Investment		18,544	25,608	28,891	29,240	29,353	29,353	29,353	29,354	29,355	29,355	30,266	33,496	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		0	0	0	0	0	0	0	2,043	273	273	281	312	$3,182
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	0	374	50	50	51	57	582
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) 0.016338		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	2,417	323	323	333	368	3,764
	a. 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	2,417	323	323	333	368	3,764
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	2,266	303	303	312	345	3,529
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$2,266	$303	$303	$312	$345	$3,529

Notes:
(A) Credit reflecting expenses recovered through base rates for breakers that were replaced to compensate for increased load due to the Modular Cooling Towers.
(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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 Rate Case Settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base - AFUDC (Project 7.4)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$7,863,379	$13,454,781	$9,113,351	$11,454,205	$9,974,205	$17,940,664	$26,593,636	$22,347,907	$40,176,001	$41,623,696	$46,711,712	$49,160,912	$296,414,450
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (B)	8.848%		146,268	170,579	142,641	167,222	245,920	300,720	416,094	496,863	642,707	764,622	1,163,458	1,535,015	6,192,709
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 Accrual		26,645,346	34,654,994	48,280,354	57,536,346	69,157,773	79,377,898	97,619,282	124,629,612	147,474,383	188,293,091	230,681,408	278,556,578	329,252,505	
5	Net Investment (Lines 2 + 3 + 4)		$26,645,346	34,654,994	48,280,354	57,536,346	69,157,773	79,377,898	97,619,282	124,629,612	147,474,383	188,293,091	230,681,408	278,556,578	329,252,505	
6	Average Net Investment			30,650,170	41,467,674	52,908,350	63,347,059	74,267,835	88,498,590	111,124,447	136,051,998	167,883,737	209,487,250	254,618,993	303,904,541	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	6.82%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.03% x 1/12)	2.03%		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)			0.93753	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	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) This schedule shown for informational purposes.
(B) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$6,035	$0	$0	$0	$3,665	$0	$0	$9,700
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$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	6,035	6,035	6,035	6,035	9,700	9,700	9,700	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	6,035	6,035	6,035	6,035	9,700	9,700	9,700	
6	Average Net Investment		0	0	0	0	0	3,017	6,035	6,035	6,035	7,867	9,700	9,700	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		0	0	0	0	0	28	56	56	56	73	90	90	$450
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	5	10	10	10	13	16	16	82
8	Investment Expenses														
	a. Depreciation (C) 4.59%		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) 0.010233		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	33	66	66	66	87	107	107	532
	a. 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	33	66	66	66	87	107	107	532
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)		0	0	0	0	0	33	66	66	66	87	107	107	530
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$33	$66	$66	$66	$87	$107	$107	$530

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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$559	$0	$0	($49,259)	$0	$0	$0	$0	$0	$0	$0	($48,700)
	b. Clearings to Plant			0	0	0	0	0	0	168,941	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	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	(690)	(1,151)	(1,611)	(2,071)	(2,532)	(2,992)	
4	CWIP - Non-Interest Bearing		217,641	217,641	218,200	218,200	218,200	168,941	168,941	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$217,641	217,641	218,200	218,200	218,200	168,941	168,941	168,251	167,791	167,330	166,870	166,410	165,949	
6	Average Net Investment			217,641	217,921	218,200	218,200	193,571	168,941	168,596	168,021	167,561	167,100	166,640	166,179	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,024	2,027	2,029	2,029	1,800	1,571	1,568	1,563	1,558	1,554	1,550	1,545	$20,819
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		370	370	371	371	329	287	287	286	285	284	283	283	3,806
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	0	0	690	460	460	460	460	460	2,992
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	460	230	230	230	230	230	1,610
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,394	2,397	2,400	2,400	2,129	1,858	3,005	2,539	2,534	2,528	2,523	2,518	29,225
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,394	2,397	2,400	2,400	2,129	1,858	3,005	2,539	2,534	2,528	2,523	2,518	29,225
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)			2,244	2,247	2,250	2,250	1,996	1,742	2,817	2,380	2,376	2,370	2,365	2,361	27,399
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,244	$2,247	$2,250	$2,250	$1,996	$1,742	$2,817	$2,380	$2,376	$2,370	$2,365	$2,361	$27,399

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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$5,635	($3,155)	$0	$0	($21,609)	$599	$138	$0	$0	$0	$0	$0	($18,392)
	b. Clearings to Plant			0	0	0	0	0	75,868	138	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	75,868	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	(1,109)	(1,311)	(1,513)	(1,715)	(1,917)	(2,119)	(2,321)	
4	CWIP - Non-Interest Bearing		94,398	100,033	96,879	96,879	96,879	75,269	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$94,398	100,033	96,879	96,879	96,879	75,269	74,759	74,695	74,493	74,291	74,089	73,887	73,685	
6	Average Net Investment			97,216	98,456	96,879	96,879	86,074	74,859	74,727	74,594	74,392	74,190	73,988	73,786	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		904	916	901	901	800	(131)	695	694	692	690	688	686	$8,436
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		165	167	165	165	146	(24)	127	127	126	126	126	125	1,542
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	0	1,111	202	202	202	202	202	202	2,323
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	372	62	62	62	62	62	62	743
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,069	1,083	1,066	1,066	947	1,328	1,086	1,084	1,082	1,080	1,078	1,076	13,045
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,069	1,083	1,066	1,066	947	1,328	1,086	1,084	1,082	1,080	1,078	1,076	13,045
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)			845	856	843	843	749	1,050	858	857	855	854	852	851	10,312
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$845	$856	$843	$843	$749	$1,050	$858	$857	$855	$854	$852	$851	$10,312

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 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Actual July 07	Actual August 07	Actual September 07	Actual October 07	Actual November 07	Actual December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$62,994	$68,001	$37,753	($645)	$2,081	$0	($22,267)	($1,411)	$0	$0	$0	$2,410	**$148,916**
	b. Clearings to Plant		0	0	0	0	0	0	147,916	(1,411)	0	0	0	2,410	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	(3,767)	(3,040)	0	426	0	(1,702)	
2	Plant-in-Service/Depreciation Base	**$516,221**	516,221	516,221	516,221	516,221	516,221	516,221	664,137	662,727	662,727	662,727	662,727	665,137	
3	Less: Accumulated Depreciation	**(64,528)**	(73,131)	(81,735)	(90,339)	(98,942)	(107,546)	(116,150)	(135,848)	(146,893)	(157,938)	(168,983)	(180,028)	(191,114)	
4	CWIP - Non-Interest Bearing	**0**	62,994	130,995	168,748	168,102	170,183	170,183	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	**$451,693**	506,083	565,481	594,630	585,381	578,858	570,254	528,290	515,834	504,789	493,744	482,699	474,023	
6	Average Net Investment		478,888	535,782	580,055	590,005	582,119	574,556	549,272	522,062	510,311	499,266	488,221	478,361	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		4,454	4,983	5,395	5,487	5,414	5,343	4,130	4,855	4,746	4,643	4,540	4,449	$58,438
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		814	911	986	1,003	990	977	755	888	868	849	830	813	10,683
8	Investment Expenses														
	a. Depreciation (C) 20.00%		8,604	8,604	8,604	8,604	8,604	8,604	19,698	11,045	11,045	11,045	11,045	11,086	126,586
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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) 0.016338		574	703	703	703	703	703	1,709	902	902	902	902	906	10,311
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8) (E)		14,445	15,200	15,687	15,797	15,710	15,627	22,525	14,650	17,561	17,865	17,317	15,552	197,936
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		14,445	15,200	15,687	15,797	15,710	15,627	22,525	14,650	17,561	17,865	17,317	15,552	197,936
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 (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (G)		13,543	14,250	14,707	14,810	14,729	14,651	21,118	13,735	16,464	16,749	16,235	14,580	185,571
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,543	$14,250	$14,707	$14,810	$14,729	$14,651	$21,118	$13,735	$16,464	$16,749	$16,235	$14,580	$185,571

Notes:
(A) Credit reflecting expenses recovered through base rates for breakers that were replaced to compensate for increased load due to the Modular Cooling Towers.
(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 2006 Effective Tax Rate on original cost.
(E) Line 9 - Line 9d. Calculation started in July when appropriate treatment was determined and included true-ups for any unrecoverable amounts prior to July 2007.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Source:
Line 8c Based on 2005 Rate Case Settlement in Dkt. 050078-EI.

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. (WG-2)

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

JANUARY 2007 - DECEMBER 2007
FINAL TRUE-UP
DOCKET NO. 080007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 13
COMPANY PEF, Inc. (Direct
WITNESS Will Garrett (WG-2)
DATE 11-04-08

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

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$270	$270
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	674,010	
5	Net Investment (Lines 2 + 3 + 4)	$673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	674,010	
6	Average Net Investment		673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,875	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,267	$75,191
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,146	13,745
8	Investment Expenses														
	a. Depreciation 1.86%		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 0.018567		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)		7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,413	88,935
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,413	88,935

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

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$1,035	$450	$270	$0	$0	$0	$1,755
	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		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	(20,420)	(20,844)	(21,268)	(21,692)	(22,116)	(22,540)	(22,964)	(23,388)	(23,812)	(24,236)	(24,660)	(25,084)	(25,508)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	1,035	1,485	1,755	1,755	1,755	1,755	
5	Net Investment (Lines 2 + 3 + 4)	$133,278	132,854	132,430	132,006	131,582	131,158	130,734	131,345	131,371	131,217	130,793	130,369	129,945	
6	Average Net Investment		133,066	132,642	132,218	131,794	131,370	130,946	131,040	131,358	131,294	131,005	130,581	130,157	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,238	1,234	1,230	1,226	1,222	1,218	1,219	1,222	1,221	1,218	1,214	1,210	$14,670
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		226	225	225	224	223	223	223	223	223	223	222	221	2,682
8	Investment Expenses														
	a. Depreciation 3.31%		424	424	424	424	424	424	424	424	424	424	424	424	5,087
	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 0.009773		(1,253)	125	125	125	125	125	125	125	125	125	125	125	124
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		635	2,008	2,004	1,999	1,994	1,990	1,991	1,994	1,993	1,990	1,986	1,981	22,564
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		635	2,008	2,004	1,999	1,994	1,990	1,991	1,994	1,993	1,990	1,986	1,981	22,564

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-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	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	(4,549)	(4,661)	(4,772)	(4,883)	(4,994)	(5,105)	(5,216)	(5,327)	(5,439)	(5,550)	(5,661)	(5,772)	(5,883)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$28,543	28,431	28,320	28,209	28,098	27,987	27,876	27,765	27,653	27,542	27,431	27,320	27,209	
6	Average Net Investment		28,487	28,376	28,265	28,154	28,042	27,931	27,820	27,709	27,598	27,487	27,376	27,264	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		265	264	263	262	261	260	259	258	257	256	255	254	$3,111
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		48	48	48	48	48	47	47	47	47	47	47	46	569
8	Investment Expenses														
	a. Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,334
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.016338		61	45	45	45	45	45	45	45	45	45	45	45	557
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		486	468	467	466	465	463	462	461	460	459	457	456	5,570
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		486	468	467	466	465	463	462	461	460	459	457	456	5,570

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

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$10,571	$36,060	($69,542)	$72,818	$297	$0	$50,203
	b. Clearings to Plant		0	0	0	0	0	0	0	0	(22,912)	72,818	297	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,591,318	1,664,136	1,664,433	1,664,433	
3	Less: Accumulated Depreciation	0	0	0	(20,520)	(25,080)	(29,641)	(34,201)	(38,761)	(43,321)	(47,202)	(54,063)	(58,765)	(63,467)	
4	CWIP - Non-Interest Bearing	1,614,230	1,614,230	1,614,230	0	0	0	0	10,571	46,631	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$1,614,230	1,614,230	1,614,230	1,593,710	1,589,150	1,584,590	1,580,029	1,586,040	1,617,539	1,544,117	1,610,073	1,605,668	1,600,966	
6	Average Net Investment		1,614,230	1,614,230	1,595,990	1,591,430	1,586,870	1,582,309	1,583,035	1,601,790	1,580,828	1,577,095	1,607,871	1,603,317	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		22,518	15,012	14,832	14,800	14,758	14,715	14,722	14,897	14,702	14,667	14,953	14,911	$185,288
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		4,116	2,744	2,675	2,705	2,698	2,690	2,691	2,723	2,687	2,681	2,733	2,726	33,870
8	Investment Expenses														
	a. Depreciation 3.39%		0	0	4,560	20,520	4,560	4,560	4,560	4,560	3,861	6,861	4,702	4,702	63,467
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.008160		0	0	5,489	1,098	1,098	1,098	1,098	1,098	926	1,676	1,132	1,132	15,843
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		26,635	17,757	27,356	39,124	23,113	23,063	23,071	23,278	22,196	25,885	23,520	23,470	298,468
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		26,635	17,757	27,356	39,124	23,113	23,063	23,071	23,278	22,196	25,885	23,520	23,470	298,468

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

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	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	(2,435)	(2,957)	(3,477)	(3,998)	(4,518)	(5,039)	(5,559)	(6,079)	(6,600)	(7,120)	(7,641)	(8,161)	(8,681)	
4	CWIP - Non-Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$176,502	175,981	175,461	174,940	174,420	173,899	173,379	172,859	172,338	171,818	171,297	170,777	170,257	
6	Average Net Investment		176,242	175,721	175,200	174,680	174,160	173,639	173,119	172,598	172,078	171,558	171,037	170,517	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,635	1,634	1,629	1,625	1,620	1,615	1,610	1,605	1,600	1,595	1,591	1,586	$19,345
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		299	299	298	297	296	295	294	293	293	292	291	290	3,536
8	Investment Expenses														
	a. Depreciation 3.49%		521	520	520	520	520	520	520	520	520	520	520	520	6,246
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010473		(830)	156	156	156	156	156	156	156	156	156	156	156	888
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,625	2,610	2,604	2,598	2,592	2,587	2,581	2,575	2,569	2,564	2,558	2,552	30,015
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,625	2,610	2,604	2,598	2,592	2,587	2,581	2,575	2,569	2,564	2,558	2,552	30,015

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

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$90	$41,457	$34,271	$2,984	$97,710	$0	$0	$0	$0	$71,042	$114,405	$266,103	$628,061
	b. Clearings to Plant		0	0	251,899	2,984	0	97,710	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	251,899	254,883	254,883	352,593	352,593	352,593	352,593	352,593	352,593	349,609	
3	Less: Accumulated Depreciation	0	0	0	(279)	(844)	(1,409)	(2,736)	(3,517)	(4,299)	(5,080)	(5,862)	(6,644)	(7,419)	
4	CWIP - Non-Interest Bearing	176,081	176,171	217,628	0	(0)	97,710	(0)	(0)	(0)	(0)	71,042	185,447	451,549	
5	Net Investment (Lines 2 + 3 + 4)	$176,081	176,171	217,628	251,620	254,039	351,183	349,858	349,075	348,294	347,512	417,773	531,396	793,740	
6	Average Net Investment		176,126	196,900	234,624	252,829	302,611	350,248	349,467	348,685	347,903	382,642	474,584	662,568	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,638	1,831	2,182	2,351	2,814	3,257	3,250	3,243	3,235	3,559	4,414	6,162	$37,936
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		299	335	399	430	514	595	594	593	591	650	807	1,126	6,935
8	Investment Expenses														
	a. Depreciation 2.66%		0	0	279	565	565	1,328	782	782	782	782	782	775	7,420
	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 0.009773		0	0	205	208	208	528	287	287	287	287	287	285	2,869
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,937	2,166	3,065	3,554	4,101	5,708	4,913	4,904	4,896	5,278	6,289	8,348	55,160
	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		1,937	2,166	3,065	3,554	4,101	5,708	4,913	4,904	4,896	5,278	6,289	8,348	55,160

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

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$4,732	$190,616	$37,849	$62,072	$413,866	$102,207	($41,557)	$192,571	$56,451	$9,632	$0	$0	$1,028,439
	b. Clearings to Plant		0	0	0	0	0	0	0	0	1,027,432	9,632	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	1,027,432	1,037,064	1,037,064	1,037,064	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(9,590)	(12,445)	(15,211)	(17,976)	
4	CWIP - Non-Interest Bearing	8,625	13,357	203,974	241,822	303,894	717,760	819,967	778,410	970,981	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$8,625	13,357	203,974	241,822	303,894	717,760	819,967	778,410	970,981	1,017,843	1,024,619	1,021,854	1,019,088	
6	Average Net Investment		10,991	108,665	222,898	272,858	510,827	768,863	799,188	874,696	994,412	1,021,231	1,023,236	1,020,471	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		102	1,011	2,073	2,538	4,751	7,150	7,432	8,135	9,248	9,497	9,516	9,490	$70,944
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		19	185	379	464	868	1,307	1,359	1,487	1,691	1,736	1,740	1,735	12,968
8	Investment Expenses														
	a. Depreciation 3.20%		0	0	0	0	0	0	0	0	9,590	2,855	2,766	2,766	17,976
	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 0.009345		0	0	0	0	0	0	0	0	3,200	838	808	808	5,653
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		121	1,195	2,452	3,001	5,619	8,457	8,791	9,622	23,728	14,927	14,829	14,798	107,541
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		121	1,195	2,452	3,001	5,619	8,457	8,791	9,622	23,728	14,927	14,829	14,798	107,541

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

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$630	$2,345	$2,155	($1,055)	$0	($595)	$3,480
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	584	584	584	584	584	584	584	1,214	3,559	5,714	4,659	4,659	4,064	
5	Net Investment (Lines 2 + 3 + 4)	$584	584	584	584	584	584	584	1,214	3,559	5,714	4,659	4,659	4,064	
6	Average Net Investment		584	584	584	584	584	584	899	2,387	4,637	5,187	4,659	4,362	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		5	5	5	5	5	5	8	22	43	48	43	41	$238
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1	1	1	1	1	1	2	4	8	9	8	7	44
8	Investment Expenses														
	a. Depreciation 2.33%		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 0.010864		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	6	6	6	6	6	10	26	51	57	51	48	282
	a. 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	6	6	6	6	6	10	26	51	57	51	48	282

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

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	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	(8,664)	(9,532)	(10,326)	(11,121)	(11,915)	(12,710)	(13,504)	(14,298)	(15,093)	(15,887)	(16,682)	(17,476)	(18,270)	
4	CWIP - Non-Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$132,771	131,903	131,108	130,314	129,520	128,725	127,931	127,136	126,342	125,548	124,753	123,959	123,164	
6	Average Net Investment		132,337	131,506	130,711	129,917	129,122	128,328	127,534	126,739	125,945	125,150	124,356	123,562	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,145	1,223	1,218	1,208	1,201	1,193	1,186	1,179	1,171	1,164	1,157	1,149	$14,191
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		209	224	222	221	220	218	217	215	214	213	211	210	2,594
8	Investment Expenses														
	a. Depreciation 6.74%		868	794	794	794	794	794	794	794	794	794	794	794	9,607
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.017522		(202)	207	207	207	207	207	207	207	207	207	207	207	2,069
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,020	2,447	2,439	2,430	2,421	2,413	2,404	2,395	2,386	2,378	2,369	2,360	28,461
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,020	2,447	2,439	2,430	2,421	2,413	2,404	2,395	2,386	2,378	2,369	2,360	28,461

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

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$189,743	$33,541	$66,766	$247	$0	$290,297
	b. Clearings to Plant		0	0	0	0	0	0	0	0	223,284	66,766	0	247	
	c. Retirements		0	0	0	0	0	0	0	0	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	223,284	290,050	290,050	290,297	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(627)	(2,349)	(3,978)	(5,609)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	189,743	0	0	247	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	189,743	222,657	287,701	286,319	284,689	
6	Average Net Investment		0	0	0	0	0	0	0	94,871	206,200	255,179	287,010	285,504	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	0	882	1,918	2,373	2,669	2,655	$10,498
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	0	161	351	434	488	485	1,919
8	Investment Expenses														
	a. Depreciation 3.34%		0	0	0	0	0	0	0	0	627	1,722	1,629	1,631	5,609
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.008723		0	0	0	0	0	0	0	0	326	472	424	424	1,645
	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	1,044	3,221	5,001	5,210	5,195	19,671
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	1,044	3,221	5,001	5,210	5,195	19,671

For Project: CAIR/CAMR - CRYSTAL RIVER NORTH - 4 & 5 (Project 7.4)
(in Dollars)

Calculated @ AFUDC - Not applicable to ECRC revenue reqmts. until placed in service.

Line	Base Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$7,863,379	$13,454,781	$9,113,351	$11,454,205	$9,974,205	$17,940,664	$26,593,636	$22,347,907	$40,176,001	$41,623,696	$46,711,712	$49,160,912	$296,414,450
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other 8.848%		146,268	170,579	142,641	167,222	*245,920*	*300,720*	*416,694*	*496,863*	*642,707*	*764,622*	1,163,458	1,535,015	6,192,709
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	26,645,346	34,654,994	48,280,354	57,536,346	69,157,773	79,377,898	97,619,282	124,629,612	147,474,383	188,293,091	230,681,408	278,556,578	329,252,505	302,607,159
5	Net Investment (Lines 2 + 3 + 4)	$26,645,346	34,654,994	48,280,354	57,536,346	69,157,773	79,377,898	97,619,282	124,629,612	147,474,383	188,293,091	230,681,408	278,556,578	329,252,505	
6	Average Net Investment		30,650,170	41,467,674	52,908,350	63,347,059	74,267,835	88,498,590	111,124,447	136,051,998	167,883,737	209,487,250	254,618,993	303,904,541	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxe 6.819%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.029% x 1/1 2.029%		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 3.27%		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 0.016338		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

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2007 through December 2007
CAIR/CAMR (Projects 7.1 and 7.4 Recap)

For Project: CAIR/CAMR - ANCLOTE (Project 7.1)
(in Dollars)

Line	Intermediate Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		($1)	$0	$0	$317	$458	$123	$0	$0	$0	$1,129	$2,414	$5,424	$9,864
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	54,328	54,326	54,326	54,326	54,644	55,102	55,225	55,225	55,225	55,225	56,354	58,767	64,192	
5	Net Investment (Lines 2 + 3 + 4)	$54,328	54,326	54,326	54,326	54,644	55,102	55,225	55,225	55,225	55,225	56,354	58,767	64,192	
6	Average Net Investment		54,327	54,326	54,326	54,485	54,873	55,163	55,225	55,225	55,225	55,789	57,560	61,479	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		505	505	505	507	510	513	514	514	514	519	535	572	$6,212
	b. Debt Component (Line 6 x 2.57% x 1/12 2.04%		92	92	92	93	93	94	94	94	94	95	98	105	1,136
8	Investment Expenses														
	a. Depreciation 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 0.008723		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)		598	598	598	599	604	607	607	607	607	614	633	676	7,348
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		598	598	598	599	604	607	607	607	607	614	633	676	7,348

Docket No. 080007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-2)
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For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

ALL Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$979	$356	$49,024	($2,614)	$48,015	$22,963	$1,095	$6,932	$529	$12,652	$3,072	$16,485	$159,486
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	159,612	16,485	
	c. Retirements		0	0	0	0	0	0	0	0	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	159,612	176,097	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(120)	(384)	
4	CWIP - Non-Interest Bearing	16,611	17,590	17,946	66,970	64,356	112,371	135,334	136,429	143,360	143,889	156,541	0	1	
5	Net Investment (Lines 2 + 3 + 4)	$16,611	17,590	17,946	66,970	64,356	112,371	135,334	136,429	143,360	143,889	156,541	159,492	175,714	
6	Average Net Investment		17,101	17,768	42,458	65,663	88,364	123,853	135,881	139,894	143,625	150,215	158,017	167,603	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		159	165	395	611	822	1,152	1,264	1,301	1,336	1,397	1,470	1,559	$11,629
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		29	30	72	112	150	211	231	238	244	255	269	285	2,126
8	Investment Expenses														
	a. Depreciation 1.80%		0	0	0	0	0	0	0	0	0	0	120	264	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 0.010473		0	0	0	0	0	0	0	0	0	0	139	154	293
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		188	195	467	722	972	1,362	1,495	1,539	1,580	1,652	1,997	2,261	14,432
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		188	195	467	722	972	1,362	1,495	1,539	1,580	1,652	1,997	2,261	14,432

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$6,991	$14,305	$14,503	$8,816	$16,002	$15,830	$1,381	$615	$418	$5,362	$2,823	$21,015	$108,060
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	244,973	21,015	
	c. Retirements		0	0	0	0	0	0	0	0	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	244,973	265,988	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(437)	(1,386)	
4	CWIP - Non-Interest Bearing	157,927	164,918	179,223	193,726	202,542	218,543	234,374	235,754	236,369	236,787	242,149	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$157,927	164,918	179,223	193,726	202,542	218,543	234,374	235,754	236,369	236,787	242,149	244,536	264,602	
6	Average Net Investment		161,423	172,070	186,474	198,134	210,542	226,458	235,064	236,062	236,578	239,468	243,342	254,569	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,501	1,600	1,734	1,843	1,958	2,106	2,186	2,195	2,200	2,227	2,263	2,367	$24,182
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		274	293	317	337	358	385	400	401	402	407	414	433	4,420
8	Investment Expenses														
	a. Depreciation 4.26%		0	0	0	0	0	0	0	0	0	0	437	949	1,386
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009773		0	0	0	0	0	0	0	0	0	0	200	217	416
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,776	1,893	2,051	2,179	2,316	2,491	2,586	2,597	2,602	2,634	3,313	3,966	30,404
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,776	1,893	2,051	2,179	2,316	2,491	2,586	2,597	2,602	2,634	3,313	3,966	30,404

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2007 through December 2007
CAIR CTs (Project 7.2 Recap)

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$434	$16,275	$6,812	$168	$6,313	$19,282	$1,000	$66	$497	$4,881	$15,320	$24,955	$96,005
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	171,525	24,955	
	c. Retirements		0	0	0	0	0	0	0	0	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	171,525	196,480	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(217)	(715)	
4	CWIP - Non-Interest Bearing	100,476	100,910	117,185	123,997	124,165	130,478	149,760	150,760	150,826	151,324	156,205	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$100,476	100,910	117,185	123,997	124,165	130,478	149,760	150,760	150,826	151,324	156,205	171,308	195,766	
6	Average Net Investment		100,693	109,048	120,591	124,081	127,322	140,119	150,260	150,793	151,075	153,764	163,757	183,537	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		936	1,014	1,121	1,154	1,184	1,303	1,397	1,402	1,405	1,430	1,523	1,707	$15,578
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		171	185	205	211	216	238	255	256	257	261	278	312	2,848
8	Investment Expenses														
	a. Depreciation 3.04%		0	0	0	0	0	0	0	0	0	0	217	498	715
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009773		0	0	0	0	0	0	0	0	0	0	140	160	300
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,108	1,200	1,327	1,365	1,401	1,541	1,653	1,659	1,662	1,691	2,158	2,677	19,440
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,108	1,200	1,327	1,365	1,401	1,541	1,653	1,659	1,662	1,691	2,158	2,677	19,440

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$180	$690	$642	$4,330	$5,369	$24,954	$3,414	$4,021	$4,976	$3,594	$7,794	$22,819	$82,782
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	63,631	22,819	
	c. Retirements		0	0	0	0	0	0	0	0	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	63,631	86,450	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(158)	(373)	
4	CWIP - Non-Interest Bearing	3,669	3,849	4,539	5,180	9,510	14,879	39,833	43,247	47,267	52,243	55,838	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$3,669	3,849	4,539	5,180	9,510	14,879	39,833	43,247	47,267	52,243	55,838	63,473	86,078	
6	Average Net Investment		3,759	4,194	4,859	7,345	12,195	27,356	41,540	45,257	49,755	54,041	59,656	74,776	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		35	39	45	68	113	254	386	421	463	503	555	695	$3,578
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		6	7	8	12	21	47	71	77	85	92	101	127	654
8	Investment Expenses														
	a. Depreciation 2.98%		0	0	0	0	0	0	0	0	0	0	158	215	373
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010864		0	0	0	0	0	0	0	0	0	0	58	78	136
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		41	46	53	81	134	301	457	498	547	594	872	1,115	4,741
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		41	46	53	81	134	301	457	498	547	594	872	1,115	4,741

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2007 through December 2007
CAIR CTs (Project 7.2 Recap)

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$6,044	$20,905	$103,646	$5,075	$15,642	$15,157	$18,001	$236	$2,873	$4,009	$23,529	$5,554	**$220,471**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0		
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	**$0**	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	**89,885**	95,930	116,835	220,480	225,555	241,197	256,354	274,355	274,592	277,265	281,274	304,803	310,357	
5	Net Investment (Lines 2 + 3 + 4)	**$89,885**	95,930	116,835	220,480	225,555	241,197	256,354	274,355	274,592	277,265	281,274	304,803	310,357	
6	Average Net Investment		92,908	106,382	168,658	223,018	233,376	248,776	265,355	274,474	275,928	279,269	293,038	307,580	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		864	989	1,569	2,074	2,170	2,314	2,468	2,553	2,566	2,597	2,725	2,860	$25,749
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		158	181	287	379	397	423	451	467	469	475	498	523	4,707
8	Investment Expenses														
	a. Depreciation **3.90%**		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 **0.009773**		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)		1,022	1,170	1,855	2,453	2,567	2,737	2,919	3,019	3,035	3,072	3,223	3,383	30,456
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,022	1,170	1,855	2,453	2,567	2,737	2,919	3,019	3,035	3,072	3,223	3,383	30,456

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$1,503	$1,280	$39,871	$8,660	$80,520	$12,983	$2,121	$14,777	$5,025	$35,754	$2,696	$2,060	**$207,248**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	325,868	2,060	
	c. Retirements		0	0	0	0	0	0	0	0	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	325,868	327,928	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	0	0	0	0	(760)	(2,291)	
4	CWIP - Non-Interest Bearing	**120,680**	122,183	123,463	163,334	171,994	252,513	265,496	267,617	282,393	287,418	323,172	0	0	
5	Net Investment (Lines 2 + 3 + 4)	**$120,680**	122,183	123,463	163,334	171,994	252,513	265,496	267,617	282,393	287,418	323,172	325,108	325,637	
6	Average Net Investment		121,432	122,823	143,398	167,664	212,253	259,005	266,556	275,005	284,906	305,295	324,140	325,373	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		1,129	1,142	1,334	1,559	1,974	2,409	2,479	2,558	2,650	2,839	3,015	3,026	$26,113
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		206	209	244	285	361	440	453	468	484	519	551	553	4,773
8	Investment Expenses														
	a. Depreciation **5.60%**		0	0	0	0	0	0	0	0	0	0	760	1,530	2,291
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes **0.008160**		0	0	0	0	0	0	0	0	0	0	222	223	445
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,336	1,351	1,577	1,844	2,335	2,849	2,932	3,025	3,134	3,358	4,547	5,332	33,622
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,336	1,351	1,577	1,844	2,335	2,849	2,932	3,025	3,134	3,358	4,547	5,332	33,622

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$3,315	$1,866	$7,945	$17,300	$27,779	$14,957	$7,239	$9,738	$24,061	($1,656)	$7,785	$844	$121,173
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	126,574	844	
	c. Retirements		0	0	0	0	0	0	0	0	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	126,574	127,418	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(254)	(766)	
4	CWIP - Non-Interest Bearing	6,245	9,560	11,426	19,370	36,670	64,449	79,406	86,646	96,383	120,444	118,788	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$6,245	9,560	11,426	19,370	36,670	64,449	79,406	86,646	96,383	120,444	118,788	126,319	126,652	
6	Average Net Investment		7,902	10,493	15,398	28,020	50,560	71,928	83,026	91,514	108,414	119,616	122,554	126,486	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		73	98	143	261	470	669	772	851	1,008	1,112	1,140	1,176	$7,774
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		13	18	26	48	86	122	141	156	184	203	208	215	1,421
8	Investment Expenses														
	a. Depreciation 4.82%		0	0	0	0	0	0	0	0	0	0	254	512	766
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010864		0	0	0	0	0	0	0	0	0	0	115	115	230
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		87	115	169	308	556	791	913	1,007	1,193	1,316	1,717	2,019	10,191
	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		87	115	169	308	556	791	913	1,007	1,193	1,316	1,717	2,019	10,191

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

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$1,890	$18,913	$7,205	$8,244	$156,465	$48,680	$9,222	$51,804	$8,998	$8,611	$9,316	$33,158	$362,506
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	9,336	11,226	30,139	37,344	45,588	202,053	250,733	259,955	311,759	320,756	329,367	338,683	371,841	
5	Net Investment (Lines 2 + 3 + 4)	$9,336	11,226	30,139	37,344	45,588	202,053	250,733	259,955	311,759	320,756	329,367	338,683	371,841	
6	Average Net Investment		10,281	20,682	33,741	41,466	123,820	226,393	255,344	285,857	316,257	325,061	334,025	355,262	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		96	192	314	386	1,152	2,105	2,375	2,658	2,941	3,023	3,106	3,304	$21,652
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		17	35	57	70	210	385	434	486	538	553	568	604	3,958
8	Investment Expenses														
	a. Depreciation 4.29%		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 0.009345		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)		113	228	371	456	1,362	2,490	2,809	3,144	3,479	3,576	3,674	3,908	25,610
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		113	228	371	456	1,362	2,490	2,809	3,144	3,479	3,576	3,674	3,908	25,610

For Project: UNDERGROUND STORAGE TANKS - CRYSTAL RIVER 4 & 5 (Project 10a)
(in Dollars)

Base

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$559	$0	$0	($49,259)	$0	$0	$0	$0	$0	$0	$0	($48,700)
	b. Clearings to Plant		0	0	0	0	0	0	168,941	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(690)	(1,151)	(1,611)	(2,071)	(2,532)	(2,992)	
4	CWIP - Non-Interest Bearing	217,641	217,641	218,200	218,200	218,200	168,941	168,941	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$217,641	217,641	218,200	218,200	218,200	168,941	168,941	168,251	167,791	167,330	166,870	166,410	165,949	
6	Average Net Investment		217,641	217,921	218,200	218,200	193,571	168,941	168,596	168,021	167,561	167,100	166,640	166,179	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxe 11.16%		2,024	2,027	2,029	2,029	1,800	1,571	1,568	1,563	1,558	1,554	1,550	1,545	$20,819
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		370	370	371	371	329	287	287	286	285	284	283	283	3,806
8	Investment Expenses														
	a. Depreciation 3.27%		0	0	0	0	0	0	690	460	460	460	460	460	2,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.016338		0	0	0	0	0	0	460	230	230	230	230	230	1,610
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,394	2,397	2,400	2,400	2,129	1,858	3,005	2,539	2,534	2,528	2,523	2,518	29,225
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,394	2,397	2,400	2,400	2,129	1,858	3,005	2,539	2,534	2,528	2,523	2,518	29,225

For Project: UNDERGROUND STORAGE TANKS - BARTOW (Project 10b)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$5,635	($3,155)	$0	$0	($21,609)	$599	$138	$0	$0	$0	$0	$0	($18,392)
	b. Clearings to Plant		0	0	0	0	0	75,868	138	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	75,868	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	(1,109)	(1,311)	(1,513)	(1,715)	(1,917)	(2,119)	(2,321)	
4	CWIP - Non-Interest Bearing	94,398	100,033	96,879	96,879	96,879	75,269	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$94,398	100,033	96,879	96,879	96,879	75,269	74,759	74,695	74,493	74,291	74,089	73,887	73,685	
6	Average Net Investment		97,216	98,456	96,879	96,879	86,074	74,859	74,727	74,594	74,392	74,190	73,988	73,786	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxe 11.16%		904	916	901	901	800	(131)	695	694	692	690	688	686	$8,436
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		165	167	165	165	146	(24)	127	127	126	126	126	125	1,542
8	Investment Expenses														
	a. Depreciation 3.19%		0	0	0	0	0	1,111	202	202	202	202	202	202	2,323
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009773		0	0	0	0	0	372	62	62	62	62	62	62	743
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,069	1,083	1,066	1,066	947	1,328	1,086	1,084	1,082	1,080	1,078	1,076	13,045
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,069	1,083	1,066	1,066	947	1,328	1,086	1,084	1,082	1,080	1,078	1,076	13,045

REDACTED

Progress Energy Florida

Review of Integrated Clean Air Compliance Plan

Submitted to the
Florida Public Service Commission

April 2, 2008

Progress Energy

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 14
COMPANY PEF, Inc. (Direct)
WITNESS Patricia Q. West (PQW-1)
DATE 11-04-08

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Executive Summary

In the 2007 Environmental Cost Recovery Clause (ECRC) Docket (No. 070007-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.

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

Sulfur Dioxide (SO_2):

- Installation of wet scrubbers (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 significant project milestones, including execution of all major contracts and commencement of construction activities, including installation of steel support for the Crystal River Unit 4 and 5 control projects. 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 contemplated in PEF's 2007 ECRC filings.

No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. Although discussion of potential regulation of carbon dioxide (CO_2) emissions continues, no legislation or regulations have been adopted to date. In any event, 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.

As a result of a recent federal appeals court decision vacating the federal CAMR regulations, the U.S. Environmental Protection Agency (EPA) may be required to adopt 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. Thus, Plan D provides PEF flexibility to respond if and when EPA adopts any new mercury standards.

I. Introduction

In its final order in the 2007 Environmental Cost Recovery Clause (ECRC) Docket (No. 070007-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 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.

II. PEF's Integrated Clean Air Compliance Plan

A. Background

The CAIR, CAMR and CAVR programs require PEF and other utilities to significantly reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx) and mercury. Under CAIR and CAMR, these reductions must be met in incremental phases. Phase I begins in 2009 for NOx and in 2010 for both SO_2 and mercury. Phase II begins in 2015 for both NOx and SO_2 and in 2018 for mercury.

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 use of the allowance markets to comply with CAIR and CAMR requirements. It also provides flexibility by making strategic use of allowance markets to account for a small portion of the reductions required by CAIR. Should it appear that allowance prices are going to be higher than currently projected, should PEF experience higher load growth than expected, or if plans for future baseload units change, PEF may then add controls on Crystal River Units 1 and 2, if necessary, possibly taking advantage of any technology improvements that may be made in the interim. The Plan also allows time for mercury control technologies to advance. Thus, the Integrated Clean Air Compliance Plan enables PEF to manage its risks. 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, 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. CAMR Mercury Plan

Installation of wet scrubbers and SCRs on Crystal River Units 4 and 5 will provide a co-benefit of reducing mercury emissions. PEF expects mercury emission reductions to be greater than required between 2010 and 2011 under the as-adopted CAMR program, and Plan D would rely on being able to bank the excess reductions for use in later years. Plan D contemplates use of CAMR's cap-and-trade feature after 2018. The Plan also includes installing powder-activated carbon (PAC) injection systems with additional polishing filters on Crystal River Unit 2 in 2017 to further reduce mercury emissions. The polishing filters would provide PEF the ability to continue selling the fly ash produced rather than disposing of the ash in a landfill, thereby avoiding additional landfill costs.

As discussed more fully below, a federal appeals court recently vacated the federal CAMR regulations. This development does not have any immediate, significant impact on PEF's implementation of Plan D because the plan does not contemplate installation of any mercury-specific controls until 2017. However, PEF will continue ongoing design of Continuous Mercury Monitors (CMMS) for Crystal River Units 1 and 2 because significant work has already been started and CMMS will likely be required in any rule the U.S. Environmental

Protection Agency (EPA) adopts in response to the federal court's vacation of CAMR.[1] 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, which will bring the Anclote units into compliance with CAIR. Per the Florida Department of Environmental Protection's (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. The results of the modeling for Crystal River Units 1 and 2 showed visibility impacts at or above regulatory threshold levels. For that reason, PEF currently is in discussions with the FDEP to determine whether and to what extent any additional controls may be required.

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.

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[1] In light of the significant pollution control projects being implemented for Crystal River Units 4 and 5, EPA granted PEF's petition for alternative mercury monitoring for those units; effectively extending the CMMS requirements for those units. As a result, PEF does not intend to go forward with design and testing of CMMS for Units 4 and 5 at this time. If, however, the rule survives as a result of any rehearing or appeal, PEF will have to perform testing this year on Units 4 and 5 to establish an emission rate to use next year for those units. Those tests will have to be repeated at least semi-annually and possibly quarterly until we install and certify the CMMS.

A. Project Milestones

PEF remains on schedule to complete installation of controls on Crystal River Units 4 and 5 as contemplated in PEF's 2007 ECRC filing. As discussed in last year's filing, PEF has executed contracts for specific project components, including contracts with:

- The Stebbins Engineering and Manufacturing Company to design, fabricate, construct, and assemble the two FGD Absorber Towers for the Crystal River Units 4 and 5 scrubber projects;

- CERAM Environmental, Inc., to design, fabricate, deliver, and test the SCR catalyst for the Crystal River Units 4 and 5 SCR projects;

- Commonwealth Dynamics, Inc., to design, fabricate and construct the Flue Gas Chimney for the Crystal River Units 4 and 5 scrubber projects; and

- Babcock & Wilcox to design and provide the major equipment for the Crystal River scrubber, LNB, and SCR projects.

Moreover, in October 2007, PEF entered into an over-arching engineering, procurement and construction (EPC) contract with Environmental Partners Crystal River (EPCR).[2] Since the Commission's final order in the 2007 ECRC docket, PEF has been working with EPCR to ensure that the Crystal River project remains on schedule to meet the in-service dates discussed in PEF's 2007 ECRC filings. The following table shows the upcoming major milestones for the Crystal River Clean Air project.

[2] All of the major Crystal River contracts were submitted for the Commissions review in the 2007 ECRC docket. *See* Hearing Exhibit Nos. 23 (TC-3) through 29 (TC-9) admitted into evidence at Hearing Transcript, p. 9 (Nov. 6, 2007).

UPCOMING CAIR COMPLIANCE MILESTONES

SCR Foundation Complete – Crystal River Unit 5 SCR	02/08
Access Road Crystal River/North – Common	04/08
Chimney Shell Complete – Common	06/08
Limestone Prep steel complete – Common	07/08
[redacted]	[redacted] 1
FGD building steel complete – Crystal River Unit 5 FGD	09/08
SCR Steel complete – Crystal River Unit 5 SCR	09/08
SCR Foundation complete – Crystal River Unit 4 SCR	09/08
Access Road Piping delivered – Crystal River Unit 4 FGD	10/08
[redacted]	[redacted] 2
[redacted]	[redacted] 3
Urea equipment delivery – Common	12/08
[redacted]	[redacted] 4
FGD building Steel complete – Crystal River Unit 4 FGD	01/09
Limestone handling complete – Common	03/09
[redacted]	[redacted] 5
[redacted]	[redacted] 6
[redacted]	[redacted] 7
SCR Steel complete – Crystal River Unit 4 SCR	06/09
[redacted]	[redacted] 8
[redacted]	[redacted] 9
[redacted]	[redacted] 10

B. Projects Costs

As of December 2007, PEF had incurred approximately $329 million in capital costs for the Crystal River projects. This figure includes approximately $301 million in contract billings, $21 million of owner's costs, and $7 million of AFUDC. The contract billings include payments for: major construction work, design and engineering work, procurement of major equipment, and environmental permits.

C. *Uncertainties*

While a significant amount of study, engineering, and analysis has been completed and construction has begun on the Crystal River projects, there are still a number of uncertainties that could affect project schedules and the 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:

- **Current and future craft labor availability**: The current market for craft labor is in short supply due to the high number of ongoing complex construction projects. The risk is that EPCR could potentially have difficulty staffing enough qualified onsite labor to complete the project according to schedule.

- **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.

- **Modification to ESP crane arrangement:** The proposed crane arrangement by General Electric/Aker Kvaerner (GE/AK) interferes with plant equipment as well as EPCR's outage lifting plans for the SCR duct and steel. PEF is working with GE/AK and EPCR to modify the lifting plans in order to monitor adherence to the critical path.

- **Condition of Certification (COC) Modification delay:** A lengthy delay in the potable water design could create a delay in receiving the necessary modifications to the existing Conditions of Certification for Crystal River Units 4 and 5.

- **Coal pile liner and/or settling pond liner not approved:** The design of the coal pile liner and the percolation pond liner must be approved by FDEP. If the submitted design is not approved, then redesign would be necessary with construction schedule slippage.

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 2007 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 two potential regulatory developments that have been the topic of discussion since the Commission's final order in Docket No. 070007-EI.

A. 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. Since PEF's 2007 CAIR filing, Governor Crist issued Executive Order 07-127 directing FDEP to promulgate regulations requiring reductions in utility carbon dioxide (CO_2) emissions. However, no such regulations have been adopted to date. FDEP currently is still in the early stages of developing a plan for implementing the Governor's CO_2 emission reduction goals. Numerous key issues, including the basic approach (i.e., cap-and-trade v. carbon tax or fee) remain unresolved. Until legislation is enacted or regulations are adopted at the state or federal level, the potential impact of CO_2 regulation will remain uncertain.

At this time, there are 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. Carbon capture and sequestration technology has never been utilized on an electric generating unit. Until numerous technological, regulatory and liability issues are resolved, it will be impossible to determine whether carbon capture and sequestration would be a feasible or cost-effective means of complying with a CO_2 regulatory regime, particularly when the requirements of the yet-to-be-adopted regulatory regime remain unknown.

Replacing coal-fired generation from Crystal River Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation[3] would not be feasible or cost-effective in light of the imminent 2009 and 2010 CAIR deadlines. Due to construction and permitting lead times, sufficient combined-cycle generation could not be placed on-line until the 2014-2015 timeframe. Thus, if PEF were to abandon Plan D in favor of replacing Units 4 and 5 with gas-fired generation, 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 4 and 5 with gas-fired generation would decrease PEF's fuel diversity and potentially increase fuel price volatility.

B. Recent Developments Related to CAMR

As noted above, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit recently issued an opinion vacating the federal CAMR regulations. *See, New Jersey v. U.S. Environmental Protection Agency*, ___ F. 3d ___, 2008 WL 341338 (D.C. Cir. Feb. 8, 2008). In 2005, 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 2000 finding that mercury emissions from electric utilities 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.

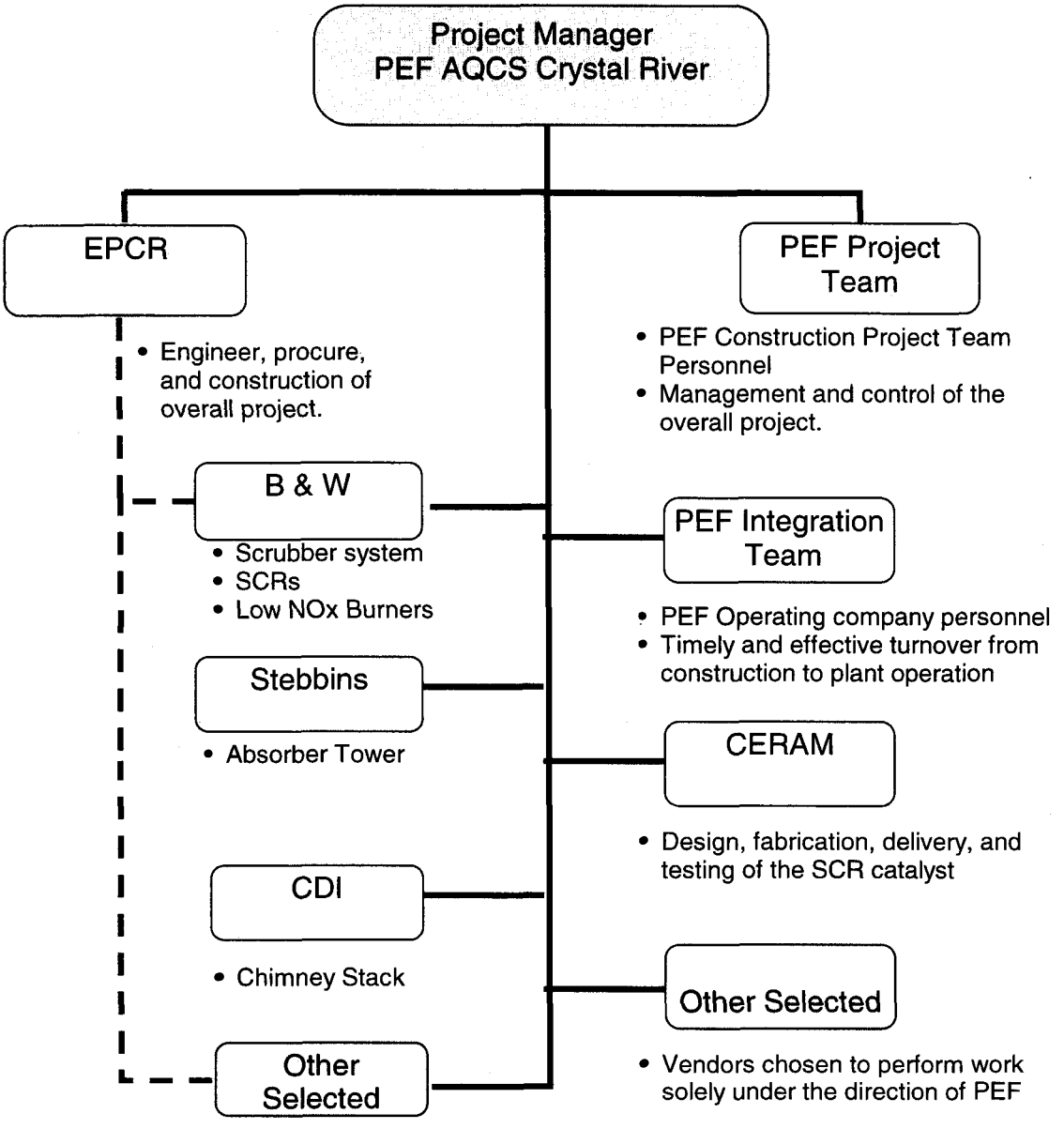
[3] The CO_2 emission rate for natural gas-fired combined cycle (NG/CC) units is approximately 50% of the emission rate for coal-fired generating units. Thus, replacing coal-fired generation with NG/CC would not eliminate costs associated with any to-be-adopted CO_2 regulatory regime.

If the D.C. Circuit's opinion stands, EPA will be required to re-evaluate whether utility mercury emissions should be regulated under CAA Section 112 and, if so, to adopt new rules establishing MACT standards. EPA has not announced any rulemaking schedule in response to the D.C. Circuit's decision. Thus, it is impossible to predict when EPA will begin the regulatory process, much less the date any rulemaking will be finalized. 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.

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 discussion of potential regulation of CO_2 emissions continues, no legislation or 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. Furthermore, replacing coal-fired generation from Crystal River Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation would not be feasible or cost-effective in light of the imminent 2009 and 2010 CAIR deadlines. Although EPA may be required to adopt new standards for utility mercury 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 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.

1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 15
COMPANY PEF, Inc. (Direct)
WITNESS Dale Wilterdink (DW-1)
DATE 11-04-08

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

JANUARY 2008 - DECEMBER 2008
Calculation of Current Period Estimated/Actual Amount
Actuals for the period of January through June 2008
Estimated for the period of July through December 2008
DOCKET NO. 080007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 16
COMPANY PEF, Inc. (Direct)
WITNESS Lori Cross (LC-1)
DATE 11-04-08

Form 42-1E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2008 through December 2008
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period (Form 42-2E, Line 5)	$ (9,844,018)
2	Interest Provision (Form 42-2E, Line 6)	(28,411)
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)	**$ (9,872,429)**

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Progress Energy Florida
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2008 through December 2008

Form 42-2E

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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$3,084,100	$2,828,489	$2,903,681	$2,981,102	$3,193,736	$3,940,477	$ 4,157,103	$ 4,247,736	$ 4,300,135	$ 3,715,029	$ 3,221,068	$ 3,141,711	$41,594,368
2	True-Up Provision	($866,816)	(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	2,829,779	2,907,200	3,119,837	3,866,576	4,083,202	4,173,834	4,226,233	3,641,128	3,147,166	3,067,809	40,707,552
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5E, Line 9)		2,910,716	2,906,273	3,793,525	3,692,843	3,874,070	4,308,114	3,891,766	3,304,046	3,188,696	2,426,943	1,986,880	1,753,628	38,036,704
	b. Capital Investment Projects (Form 42-7E, Line 9)		626,711	854,785	725,996	912,241	1,058,163	1,166,028	1,200,453	1,194,200	1,184,364	1,178,427	1,180,948	1,227,540	12,511,866
	c. Total Jurisdictional ECRC Costs		3,537,427	3,763,058	4,519,521	4,605,084	4,932,233	5,474,142	5,092,231	4,498,246	4,373,282	3,605,370	3,167,828	2,981,168	50,551,570
5	Over/(Under) Recovery (Line 3 - Line 4c)		(547,226)	(1,008,470)	(1,789,742)	(1,697,884)	(1,812,396)	(1,608,566)	(1,009,029)	(324,412)	(147,029)	35,758	(20,662)	86,641	(9,844,018)
6	Interest Provision (Form 42-3E, Line 10)		14,916	9,838	3,794	1,757	(2,000)	(5,173)	(7,729)	(8,954)	(9,302)	(9,264)	(9,137)	(8,937)	(28,411)
7	Beginning Balance True-Up & Interest Provision		(866,816)	(1,345,227)	(2,270,158)	(3,960,294)	(5,602,430)	(7,342,924)	(8,853,781)	(9,826,816)	(10,086,083)	(10,168,512)	(10,068,137)	(10,024,035)	(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
8	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
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		4,217,490	3,292,560	1,582,512	(39,712)	(1,780,207)	(3,321,045)	(4,263,901)	(4,523,366)	(4,605,795)	(4,505,420)	(4,461,318)	(4,309,712)	(4,309,712)
10	Adjustments to Period Total True-Up Including Interest (a)		0	0	0	0	0	0	0	0	0	0	0	0	0
11	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)	($4,263,901)	($4,523,366)	($4,605,795)	($4,505,420)	($4,461,318)	($4,309,712)	($4,309,712)

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Form 42-3E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2008 through December 2008

Interest Provision
(in Dollars)

Line	Description	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	$4,675,901	$4,217,490	$3,292,559	$1,582,513	($39,713)	($1,780,207)	($3,321,044)	($4,263,901)	($4,523,366)	($4,605,795)	($4,505,420)	($4,461,318)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	4,202,574	3,282,921	1,576,719	(41,469)	(1,778,207)	(3,315,871)	(4,256,172)	(4,514,412)	(4,596,493)	(4,496,136)	(4,452,181)	(4,300,775)	
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)	(7,577,217)	(8,778,313)	(9,119,859)	(9,101,931)	(8,957,601)	(8,762,093)	
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)	(3,788,609)	(4,389,157)	(4,559,930)	(4,550,966)	(4,478,801)	(4,381,047)	
5	Interest Rate (First Day of Reporting Business Month)	4.98%	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.45%	2.45%	2.45%	2.45%	2.45%	
6	Interest Rate (First Day of Subsequent Business Month)	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.45%	2.45%	2.45%	2.45%	2.45%	2.45%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.06%	6.17%	5.72%	5.47%	5.27%	4.88%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	
8	Average Interest Rate (Line 7 x 1/2)	4.030%	3.085%	2.860%	2.735%	2.635%	2.440%	2.450%	2.450%	2.450%	2.450%	2.450%	2.450%	
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%	0.204%	0.204%	0.204%	0.204%	
10	Interest Provision for the Month (Line 4 x Line 9)	$14,916	$9,638	$5,794	$1,757	($2,000)	($5,173)	($7,729)	($8,954)	($9,302)	($9,284)	($9,137)	($8,937)	($28,411)

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PROGRESS ENERGY FLORIDA

Form 42 4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2008 through December 2008

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	$1,733,861	$1,412,855	$321,006	23%
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention - Demand	3,193,542	777,618	2,415,924	311%
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention - Demand	15,348,112	14,920,605	427,507	3%
3	Pipeline Integrity Management - Demand	483,057	337,000	146,057	43%
4	Above Ground Tank Secondary Containment - Demand	368,303	0	368,303	N/A
5	SO2 Emissions Allowances - Energy	14,911,514	16,561,071	(1,649,557)	-10%
6	Phase II Cooling Water Intake - Demand	109,372	147,500	(38,128)	-26%
7.2	CAIR/CAMR - Peaking - Demand	0	48,500	(48,500)	-100%
8	Arsenic Groundwater Standard - Base - Demand	0	77,669	(77,669)	-100%
9	Sea Turtle - Coastal Street Lighting - Distrib - Demand	106,711	280,000	(173,289)	-62%
11	Modular Cooling Towers - Base - Demand	3,336,752	3,336,752	0	0%
12	Greenhouse Gas Inventory and Reporting - Energy	7,440	0	7,440	N/A
2	Total O&M Activities - Recoverable Costs	**$39,598,665**	**$37,899,570**	**$1,699,095**	4%
3	Recoverable Costs Allocated to Energy	14,918,954	16,561,071	(1,642,117)	-10%
4	Recoverable Costs Allocated to Demand	24,679,710	21,338,499	3,341,211	16%

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)

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2008 through December 2008

Form 42-5E

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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$61,896	$59,344	$394,789	$317,657	$233,421	$311,208	$59,260	$59,260	$59,260	$59,260	$59,260	$59,260	$1,733,861
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	178,491	452,322	121,795	(1,852)	606,200	174,267	277,220	277,220	277,220	277,220	277,220	277,220	3,193,542
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	1,353,452	1,216,372	1,617,242	2,336,394	1,961,067	1,696,586	1,271,500	710,000	673,500	1,014,500	673,000	402,500	15,346,112
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	4,150	91,648	14,562	16,639	30,437	16,110	23,800	40,500	45,000	47,000	61,012	90,000	483,057
	4 Above Ground Tank Secondary Containment - Pkg	270	190	367,843	0	0	0	0	0	0	0	0	0	368,303
	5 SO2 Emissions Allowances - Energy	1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,506	1,547,341	1,532,376	1,445,814	1,109,914	779,632	995,569	14,911,514
	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	7,895	6,466	202	30,000	0	0	0	0	0	70,314
	7.2 CAIR/CAMR - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	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	500	500	500	500	500	500	106,711
	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	1,488	1,488	1,488	1,488	1,488	7,440
2	Total of O&M Activities	2,989,682	2,990,672	4,002,039	3,838,377	4,023,522	4,529,411	4,043,809	3,455,534	3,336,969	2,509,882	2,052,112	1,826,657	$39,598,665
3	Recoverable Costs Allocated to Energy	1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,506	1,547,341	1,533,866	1,447,302	1,111,402	781,120	997,177	14,918,964
4	Recoverable Costs Allocated to Demand - Transm	61,896	59,344	394,789	317,657	233,421	311,208	59,260	59,260	59,260	59,260	59,260	59,260	1,733,861
	Recoverable Costs Allocated to Demand - Distrib	1,532,294	1,670,114	1,939,328	2,334,190	2,586,268	1,974,852	1,549,220	987,720	951,220	1,292,220	1,150,720	680,220	18,648,365
	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	53,800	40,500	45,000	47,000	61,012	90,000	553,831
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	367,843	0	0	0	0	0	0	0	0	0	367,843
5	Retail Energy Jurisdictional Factor	0.96490	0.96670	0.96840	0.96830	0.94630	0.95240	0.95800	0.95470	0.95490	0.95460	0.96110	0.96590	
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	
7	Jurisdictional Energy Recoverable Costs (A)	1,305,066	1,130,243	1,232,181	1,110,838	1,104,267	1,326,222	1,482,353	1,464,382	1,382,029	1,060,944	750,734	963,173	14,312,432
8	Jurisdictional Demand Recoverable Costs - Transm (B)	43,690	41,895	278,709	224,256	164,786	219,703	41,835	41,835	41,835	41,835	41,835	41,835	1,224,051
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,526,119	1,663,383	1,931,512	2,324,784	2,575,845	1,966,893	1,542,977	983,739	947,387	1,287,012	1,146,063	677,479	18,573,213
	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	42,527	32,014	35,571	37,152	48,228	71,141	437,783
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	327,303	0	0	0	0	0	0	0	0	0	327,303
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$2,910,716	$2,906,273	$3,793,525	$3,692,843	$3,874,070	$4,308,114	$3,891,766	$3,304,046	$3,186,895	$2,426,943	$1,986,860	$1,753,628	$36,039,704

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 2008 through December 2008

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	$521,581	$455,973	$65,608	14%
4.x	Above Ground Tank Secondary Containment - Demand	798,905	910,326	(111,421)	-12%
5	SO2/NOx Emissions Allowances - Energy	9,616,405	5,161,907	4,454,498	86%
7.x	CAIR/CAMR - Demand	2,094,513	437,299	1,657,214	379%
9	Sea Turtle - Coastal Street Lighting -Distribution - Demand	2,398	4,274	(1,876)	-44%
10.x	Underground Storage Tanks-Base - Demand	41,499	42,156	(657)	-2%
11	Modular Cooling Towers - Base - Demand	192,713	185,756	6,957	4%
2	Total Capital Investment Activities - Recoverable Costs	**13,268,014**	**7,197,691**	**$6,070,323**	84%
3	Recoverable Costs Allocated to Energy	9,616,405	5,161,907	$4,454,498	86%
4	Recoverable Costs Allocated to Demand	$3,651,609	$2,035,784	$1,615,825	79%

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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2008 through December 2008

Form 42-7E

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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Description of Investment Projects (A)													
	3 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$35,507	$36,432	$35,356	$35,521	$88,845	$37,302	$38,867	$40,575	$41,406	$42,587	$44,163	$46,020	$521,581
	4.1 Above Ground Tank Secondary Containment - Peaking	62,325	63,919	(126,152)	61,942	64,222	66,957	74,823	81,443	87,581	95,867	103,062	112,643	746,652
	4.2 Above Ground Tank Secondary Containment - Base	440	438	437	436	434	433	432	431	430	428	427	426	5,192
	4.3 Above Ground Tank Secondary Containment - Intermediate	5,101	5,083	5,065	5,047	5,026	5,011	(5,163)	3,995	3,987	3,978	3,969	3,960	45,061
	5 SO2/NOX Emissions Allowances - Energy	513,508	745,789	787,863	805,444	828,812	861,783	882,405	865,750	849,443	835,386	824,994	815,230	9,616,405
	7.1 CAIR/CAMR Anclote- Intermediate	706	706	706	706	706	706	706	706	706	706	706	706	8,472
	7.2 CAIR CT's - Peaking	27,094	26,453	26,497	26,502	13,374	26,129	26,287	26,286	26,249	26,206	26,171	26,134	309,364
	7.3 CAMR Crystal River - Base	410	590	866	1,031	1,240	1,502	1,611	1,611	1,611	1,611	1,611	7,166	20,860
	7.4 CAIR/CAMR Crystal River AFUDC - Base	0	0	0	0	118,130	223,170	227,819	230,327	229,636	229,349	228,859	268,305	1,755,797
	9 Sea Turtle - Coastal Street Lighting -Distribution	106	106	106	109	110	110	156	210	273	327	362	423	2,398
	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	15,961	15,880	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	864,674	899,867	749,966	957,830	1,139,864	1,243,936	1,271,888	1,270,657	1,260,718	1,255,513	1,253,281	1,299,820	13,268,814
3	Recoverable Costs Allocated to Energy	513,508	745,789	787,863	805,444	828,812	861,783	882,405	865,750	849,443	835,386	824,994	815,230	9,616,405
	Recoverable Costs Allocated to Demand - Distribution	106	106	106	109	110	110	156	210	273	327	362	423	2,398
4	Recoverable Costs Allocated to Demand - Production - Base	19,265	19,317	19,465	19,501	137,711	242,885	252,756	250,643	250,027	249,410	248,791	293,664	2,003,435
	Recoverable Costs Allocated to Demand - Production - Intermediate	42,378	42,283	42,187	42,332	95,635	44,072	35,461	46,325	47,145	48,315	49,881	51,726	587,740
	Recoverable Costs Allocated to Demand - Production - Peaking	89,419	92,372	(99,656)	90,444	77,596	95,086	101,110	107,729	113,630	122,075	129,258	136,777	1,056,036
5	Retail Energy Jurisdictional Factor	0.96490	0.96670	0.96840	0.96830	0.94630	0.95240	0.95800	0.95470	0.95490	0.95460	0.96110	0.96590	
	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	762,987	779,911	784,305	820,782	845,344	826,532	811,133	797,459	792,902	787,431	9,225,182
	Jurisdictional Demand Recoverable Costs - Distribution (B)	106	106	106	109	110	110	155	209	272	326	361	421	2,398
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	18,062	18,110	18,249	18,283	129,108	227,712	236,968	234,985	234,408	233,829	233,249	275,319	1,878,280
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	33,496	33,423	33,347	33,462	75,596	34,837	28,031	36,618	37,266	38,191	39,429	40,887	464,585
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	79,564	82,192	(88,672)	80,476	69,044	84,607	89,967	95,856	101,285	108,621	115,008	123,482	941,430
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	$1,200,463	$1,194,200	$1,184,364	$1,178,427	$1,180,948	$1,227,540	$12,511,865

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 8

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exh. No.__(LC-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$43,664	$0	$28,993	$273,667	$55,246	$113,988	$116,989	$185,989	$159,672	$990,209
	b. Clearings to Plant			0	0	0	0	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		$2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	2,674,568	
3	Less: Accumulated Depreciation		(264,167)	(261,010)	(267,853)	(274,696)	(281,539)	(354,101)	(363,210)	(372,319)	(381,428)	(390,537)	(399,646)	(408,755)	(417,864)	
4	CWIP - Non-Interest Bearing		22,685	22,685	22,685	22,685	66,349	66,349	95,342	369,009	424,255	538,244	657,233	843,223	1,012,894	
5	Net Investment (Lines 2 + 3 + 4)		$2,443,106	2,436,263	2,429,420	2,422,577	2,459,398	2,386,837	2,406,721	2,671,278	2,717,415	2,822,295	2,932,176	3,108,986	3,269,619	
6	Average Net Investment			2,439,685	2,432,842	2,425,999	2,440,988	2,423,122	2,396,779	2,538,999	2,694,347	2,769,859	2,877,235	3,020,816	3,189,337	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		22,686	22,624	22,560	22,700	22,535	22,291	23,613	25,058	25,760	26,758	28,092	29,661	294,340
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		4,148	4,137	4,125	4,150	4,119	4,074	4,317	4,580	4,706	4,892	5,134	5,422	53,807
	c. Other			0	0	0	0	-12208	0	0	0	0	0	0	0	-12208
8	Investment Expenses															
	a. Depreciation (C)			6,843	6,843	6,843	6,843	9,109	9,109	9,109	9,109	9,109	9,109	9,109	9,109	100,244
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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)			1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	21,936
	e. Other (G)			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	38,867	40,575	41,406	42,587	44,163	46,020	521,581
	a. 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	38,867	40,575	41,406	42,587	44,163	46,020	521,581
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	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			28,067	28,008	27,948	28,078	70,228	29,486	30,723	32,073	32,730	33,663	34,909	36,377	412,289
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$28,067	$28,008	$27,948	$28,078	$70,228	$29,486	$30,723	$32,073	$32,730	$33,663	$34,909	$36,377	$412,289

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 2006 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 2006 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 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Depreciation true-up amount.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			($65,198)	$304,167	$44,654	$39,638	$306,364	$466,094	$595,000	$300,000	$675,000	$657,000	$480,000	$465,000	$4,877,718
	b. Clearings to Plant			383,286	(2,767)	(2)	0	0	0	0	1,170,000	0	0	0	2,666,778	
	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	3,888,464	3,885,677	3,885,675	3,885,675	3,885,675	3,885,675	3,885,675	5,055,675	5,055,675	5,055,675	5,055,675	7,721,451	
3	Less: Accumulated Depreciation		(141,321)	(151,709)	(162,478)	(180,096)	(190,874)	(201,652)	(212,430)	(216,368)	(228,055)	(240,851)	(253,247)	(265,843)	(281,027)	
4	CWIP - Non-Interest Bearing		1,131,378	702,913	1,009,857	686,580	726,318	1,122,683	1,588,776	2,293,776	1,333,776	2,008,776	2,865,776	3,345,776	1,145,000	
5	Net Investment (Lines 2 + 3 + 4)		$4,515,235	4,439,667	4,733,056	4,392,259	4,421,119	4,806,705	5,262,021	5,973,083	6,161,395	6,823,600	7,668,204	8,135,608	8,585,424	
6	Average Net Investment			4,477,446	4,686,361	4,378,741	4,406,689	4,613,912	5,044,363	5,577,552	6,017,229	6,492,596	7,246,002	7,901,906	8,360,516	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		41,640	42,653	40,721	40,963	42,909	46,913	51,872	55,960	60,380	67,387	73,486	77,753	642,659
	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	9,482	10,230	11,039	12,318	13,432	14,214	117,477
	c. Other (G)			0	0	(169,785)	0	0	0	0	0	0	0	0	0	(169,785)
8	Investment Expenses															
	a. Depreciation (C)			10,379	10,778	10,778	10,778	10,778	10,778	10,778	11,687	12,596	12,596	12,596	15,184	139,706
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	3,566	3,566	3,566	3,566	5,492	38,595
	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	(126,152)	61,942	64,222	68,957	74,823	81,443	87,581	95,867	103,082	112,643	748,652
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			62,325	63,919	(126,152)	61,942	64,222	68,957	74,823	81,443	87,581	95,867	103,082	112,643	748,652
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	66,577	72,467	77,929	85,301	91,721	100,229	666,143
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$55,456	$56,874	($114,028)	$55,115	$57,144	$61,357	$66,577	$72,467	$77,929	$85,301	$91,721	$100,229	$666,143

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. The expense is recovered on Line 4 of 42-5E.
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.55%, 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
(G) Credit in March due to portion of the previously recovered return on investment, including interest, related to the original work for tank at Turner plant that subsequently failed (Project 4.1a on Capital Program Detail file).

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated 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	
										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	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		253	251	250	249	248	247	245	245	244	243	242	241	2,959
	b. Debt Component (Line 6 x 2.04% 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 (C)			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 (D)			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
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	401	400	399	4,868
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$413	$411	$410	$409	$407	$406	$405	$404	$403	$401	$400	$399	$4,868

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 1.629002). 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 Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated 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		(5,609)	(7,240)	(8,871)	(10,502)	(12,133)	(13,764)	(15,395)	(16,203)	(17,011)	(17,819)	(18,627)	(19,435)	(20,243)	
4	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	274,095	273,287	272,479	271,671	270,863	270,055	
6	Average Net Investment			283,873	282,242	280,611	278,980	277,349	275,718	274,499	273,691	272,883	272,075	271,267	270,459	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.15%		2,640	2,625	2,610	2,595	2,579	2,564	2,553	2,545	2,538	2,530	2,523	2,515	30,817
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		483	480	477	474	471	469	467	465	464	463	461	460	5,634
	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 (G)			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	(5,163)	3,996	3,987	3,978	3,969	3,960	45,061
	a. 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	(5,163)	3,996	3,987	3,978	3,969	3,960	45,061
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	(4,081)	3,158	3,152	3,144	3,137	3,130	35,619
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$4,032	$4,018	$4,004	$3,989	$3,974	$3,961	($4,081)	$3,158	$3,152	$3,144	$3,137	$3,130	$35,619

Notes:
(A) N/A
(B) Line 6 x 11.15% 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
(G) Depreciation true-up amount.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2006 through December 2006

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

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Estimated July 06	Estimated August 06	Estimated September 06	Estimated October 06	Estimated November 06	Estimated December 06	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1561001 SO_2 Emission Allowance Inventory		$2,905,441	$24,864,494	$23,379,360	$22,091,064	$20,927,963	$19,465,183	$18,000,751	$16,381,503	$14,777,217	$13,259,495	$12,077,675	$11,226,135	$10,158,539	$10,158,539
	b. 25401FL Auctioned SO_2 Allowance		(2,819,949)	(2,004,023)	(1,988,105)	(1,972,189)	(1,956,272)	(2,505,605)	(2,484,897)	(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		38,643,433	41,256,433	50,890,808	51,346,836	56,006,836	58,816,084	65,467,104	$65,505,363	$69,518,658	$65,518,658	$65,518,658	$65,518,658	$65,518,658	$65,518,658
2	Total Working Capital		$29,648,933	63,816,903	71,782,092	71,465,733	74,978,528	75,714,646	80,979,182	79,464,095	77,944,992	76,499,178	75,389,264	74,609,632	73,613,943	73,613,943
3	Average Net Investment			46,682,413	67,799,992	71,623,912	73,222,131	75,346,587	78,343,904	80,218,628	78,704,544	77,222,085	75,944,221	74,909,448	74,111,787	
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	746,033	731,952	718,165	706,281	697,495	689,240	$8,130,232
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		79,360	115,258	121,761	124,478	128,066	133,185	136,372	133,796	131,278	129,105	127,499	125,999	1,466,173
5	Total Return Component (B)			513,506	745,788	787,863	805,444	828,812	861,783	882,405	865,750	849,443	835,386	824,994	815,239	9,616,405
6	Expense Dr (Cr)															
	a. 5060001 SO_2 allowance expense			1,368,457	1,185,094	1,288,306	1,163,121	1,462,809	1,464,412	$1,619,249	$1,604,286	$1,517,721	$1,181,821	$651,539	$1,087,566	15,774,402
	b. 4074004 Amortization Expense			($15,917)	($15,917)	($15,917)	($15,917)	($295,809)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($862,886)
7	Net Expense (C)			1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,505	1,547,341	1,532,378	1,445,814	1,109,914	779,632	985,659	14,911,514
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	2,429,746	2,398,128	2,295,257	1,945,300	1,804,626	1,810,918	24,527,919
	a. Recoverable costs allocated to Energy			1,866,046	1,914,966	2,060,252	1,952,648	1,995,743	2,254,288	2,429,746	2,398,128	2,295,257	1,945,300	1,804,626	1,810,918	24,527,919
	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	0.96870	0.96840	0.96830	0.94630	0.95240	0.95600	0.95470	0.95490	0.95480	0.96110	0.96590	
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	2,327,697	2,289,493	2,191,741	1,858,953	1,542,208	1,749,167	23,530,485
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	$ 2,327,697	$ 2,289,493	$ 2,191,741	$ 1,858,953	$ 1,542,208	$ 1,749,167	$ 23,530,485

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 1.629002). 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 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$7	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7
	b. Clearings to Plant		0	0	0	0	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	64,198	
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	64,198	
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	64,198	
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	597	$7,164
	b. Debt Component (Line 6 x 2.87% x 1/12)	2.84%	109	109	109	109	109	109	109	109	109	109	109	109	1,308
	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	706	8,472
	a. 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	706	8,472
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	558	6,697
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$6,697

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

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exh. No.__(LC-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2008 through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.3 - 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$23,317	$11,748	$5,189	$4,727	$20,457	$26,428	$7,400	$200	$200	$200	$200	$200	$100,266
	b. Clearings to Plant			705,515	11,748	5,189	4,727	20,457	26,428	7,400	200	200	200	200	200	
	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		$1,168,361	1,866,876	1,897,624	1,902,813	1,907,540	1,927,997	1,954,426	1,961,826	1,962,026	1,962,226	1,962,426	1,962,626	1,962,826	
3	Less: Accumulated Depreciation		(8,914)	(11,174)	(17,656)	(24,156)	(30,672)	(21,562)	(25,234)	(28,912)	(32,590)	(36,268)	(39,946)	(43,627)	(47,306)	
4	CWIP - Non-Interest Bearing		682,200	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,859,647	1,874,704	1,879,970	1,878,656	1,876,870	1,906,437	1,929,193	1,932,915	1,929,437	1,926,958	1,922,479	1,919,000	1,915,521	
6	Average Net Investment			1,866,675	1,877,337	1,879,314	1,877,765	1,891,663	1,917,816	1,931,054	1,931,177	1,927,698	1,924,219	1,920,740	1,917,261	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,351	17,460	17,477	17,465	17,674	17,837	17,960	17,959	17,928	17,893	17,861	17,831	212,696
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,172	3,191	3,196	3,193	3,266	3,260	3,284	3,284	3,277	3,271	3,265	3,258	38,916
	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	3,678	3,678	3,679	3,679	3,679	3,679	41,392
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	1,365	1,365	1,365	1,365	1,366	1,366	16,178
	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	26,287	26,286	26,249	26,208	26,171	26,134	309,384
	a. 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	26,287	26,286	26,249	26,208	26,171	26,134	309,384
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	23,390	23,389	23,356	23,320	23,287	23,254	275,287
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$24,108	$25,317	$25,356	$25,361	$11,900	$23,249	$23,390	$23,389	$23,356	$23,320	$23,287	$23,254	$275,287

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 Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$2,974	$29,737	$20,357	$9,793	$28,042	$19,736	$0	$0	$0	$0	$0	$1,010,000	$1,120,639
	b. Clearings to Plant			0	0	0	0	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	146,453	146,453	146,453	146,453	146,453	1,156,453	
5	Net Investment (Lines 2 + 3 + 4)		$35,814	38,788	68,525	88,881	98,675	126,717	146,453	146,453	146,453	146,453	146,453	146,453	1,156,453	
6	Average Net Investment			37,301	53,656	78,703	93,778	112,696	136,585	146,453	146,453	146,453	146,453	146,453	651,453	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		347	499	732	872	1,048	1,270	1,362	1,362	1,362	1,362	1,362	6,059	$17,637
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		63	91	134	159	192	232	249	249	249	249	249	1,107	3,223
	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	1,611	1,611	1,611	1,611	1,611	7,166	20,860
	a. 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	1,611	1,611	1,611	1,611	1,611	7,166	20,860
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	1,510	1,510	1,510	1,510	1,510	6,718	19,557
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$384	$553	$812	$967	$1,163	$1,408	$1,510	$1,510	$1,510	$1,510	$1,510	$6,718	$19,557

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 2006 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 2006 rate case settlement in Dkt. 060078-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 Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$56,759,253	$53,940,373	$45,796,073	$49,539,746	$51,759,576	$44,201,549	39,985,078	39,348,815	35,806,869	38,880,817	37,377,404	33,432,767	$527,427,419
	b. Clearings to Plant			0	0	0	0	15,150,877	101,267	496,302	0	0	0	0	5,279,199	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (A)	8.848%		2,091,785	2,591,334	3,263,937	3,348,228	3,707,016	3,977,574	4,232,335	4,437,862	4,696,833	5,013,367	5,318,195	5,587,393	48,267,879
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	15,150,877	15,251,944	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	21,027,445	
3	Less: Accumulated Depreciation		0	0	0	0	0	(21,401)	(64,488)	(108,977)	(153,466)	(197,955)	(242,444)	(286,933)	(337,647)	
4	CWIP - AFUDC-Interest Bearing		329,252,505	388,103,541	444,635,248	493,694,258	546,582,232	586,886,149	634,976,005	678,697,116	722,483,893	763,789,585	807,483,790	850,179,389	885,930,380	575,695,290
5	Net Investment (Lines 2 + 3 + 4)		329,252,505	388,103,541	444,635,248	493,694,258	546,582,232	602,027,426	650,163,461	694,336,385	738,078,673	779,339,676	822,989,582	865,640,702	904,619,178	
6	Average Net Investment			358,678,023	416,369,394	469,164,753	520,138,245	574,304,829	626,095,443	672,249,923	716,207,529	758,709,275	801,164,734	844,315,147	885,129,425	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	0	70,351	140,747	143,118	145,238	144,825	144,411	143,997	168,102	1,100,789
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	12,860	25,728	26,161	26,549	26,473	26,398	26,322	30,728	201,219
	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	44,489	44,489	44,489	44,489	44,489	50,714	337,647
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	14,051	14,051	14,051	14,051	14,051	18,761	116,142
	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	116,130	223,170	227,819	230,327	229,838	229,349	228,859	268,305	1,755,797
	a. 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	116,130	223,170	227,819	230,327	229,838	229,349	228,859	268,305	1,755,797
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	213,587	215,938	215,480	215,022	214,562	251,544	1,646,112
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$110,750	$209,229	$213,587	$215,938	$215,480	$215,022	$214,562	$251,544	$1,646,112

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 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. Based on 2007 Effective Tax Rate on original cost.

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exh. No.___(LC-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated December 08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$351	$0	$0	$3,275	$3,275	$3,275	$3,275	$3,275	$3,275	$20,000
	b. Clearings to Plant		0	0	0	0	0	0	10,051	0	9,825	0	0	9,825	
	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	19,876	19,876	19,876	29,701	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(19)	(57)	(114)	(190)	(286)	(381)	
4	CWIP - Non-Interest Bearing	9,700	9,700	9,700	9,700	10,051	10,051	10,051	3,275	6,550	(0)	3,274	6,549	0	
5	Net Investment (Lines 2 + 3 + 4)	$9,700	9,700	9,700	9,700	10,051	10,051	10,051	13,307	16,544	19,762	22,960	26,139	29,340	
6	Average Net Investment		9,700	9,700	9,700	9,876	10,051	10,051	11,679	14,925	18,153	21,361	24,550	27,750	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		90	90	90	92	93	93	109	139	169	199	228	258	$1,650
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		16	16	16	17	17	17	20	25	31	36	42	47	300
	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	19	38	57	76	76	95	361
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement	N/A	N/A	N/A	N/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	16	16	16	23	87
	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	210	273	327	362	423	2,398
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		106	106	106	109	110	110	156	210	273	327	362	423	2,398
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)		0.99597	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	156	209	272	326	361	421	2,388
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$106	$106	$106	$108	$110	$110	$155	$209	$272	$326	$361	$421	$2,388

Notes:
(A) N/A
(B) Line 6 x 11.10% 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 Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated 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) 0.910707		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 6.55%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2006 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 Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated 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)	(2,529)	(2,728)	(2,927)	(3,129)	(3,331)	(3,533)	(3,735)	(3,937)	(4,139)	(4,341)	(4,543)	(4,748)	
4	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) 11.15%		684	682	681	679	677	675	673	671	669	667	666	664	$8,068
	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	1,479
	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 11.15% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 8.85%, 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 Current Period Estimated/Actual 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	Estimated July 08	Estimated August 08	Estimated September 08	Estimated October 08	Estimated November 08	Estimated 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		(191,116)	(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	462,936	451,853	440,767	429,681	418,595	407,509	396,423	385,337	374,251	363,166	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	15,660	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	15,660	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	14,669	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	$14,669	$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.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2008 through December 2008

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	$990,209	$657,502	$332,707	51%
4.1	Above Ground Tank Secondary Containment - Peaking	4,577,738	2,675,000	1,902,738	71%
4.2	Above Ground Tank Secondary Containment - Base	0	93,000	(93,000)	-100%
4.3	Above Ground Tank Secondary Containment - Intermediate	0	-	-	N/A
5	SO2/NOX Emissions Allowances - Energy (A)	73,613,943	33,546,476	40,067,467	119%
7.1	CAIR/CAMR Anclote- Intermediate	7	300,000	(299,993)	-100%
7.2	CAIR CT's - Peaking	100,266	-	100,266	100%
7.3	CAMR Crystal River - Base	1,120,639	2,693,308	(1,572,669)	-58%
7.4	CAIR/CAMR Crystal River AFUDC - Base	527,427,410	569,922,004	(42,494,594)	-7%
9	Sea Turtle - Coastal Street Lighting -Distribution	20,000	20,000	(0)	0%
10.1	Underground Storage Tanks-Base	0	-	-	N/A
10.2	Underground Storage Tanks-Intermediate	0	-	-	N/A
11	Modular Cooling Towers - Base	4	-	4	N/A
2	Total Investment Projects - Capital Expenditures	607,850,216	609,907,290	(2,057,074)	0%

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

JANUARY 2008 - DECEMBER 2008
Calculation of Current Period Estimated/Actual Amount
Actuals for the period of January through June 2008
Estimated for the period of July through December 2008
DOCKET NO. 080007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 17
COMPANY PEF, Inc. (Direct)
WITNESS Lori Cross (LC-2)
DATE 11-04-08

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3 1 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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	0.008202		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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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	0.008202		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

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$43,664	$0	$28,993	$273,667	$55,246	$113,989	$118,989	$185,989	$169,672	**$990,209**
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		22,685	22,685	22,685	22,685	66,349	66,349	95,342	369,009	424,254	538,244	657,233	843,222	1,012,894	
5	Net Investment (Lines 2 + 3 + 4)		$22,685	22,685	22,685	22,685	66,349	66,349	95,342	369,009	424,254	538,244	657,233	843,222	1,012,894	
6	Average Net Investment			22,685	22,685	22,685	44,517	66,349	80,846	232,175	396,632	481,249	597,738	750,228	928,058	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	**11.16%**		211	211	211	414	617	752	2,159	3,689	4,476	5,559	6,977	8,631	$33,907
	b. Debt Component (Line 6 x 2.04% x 1/12)	**2.04%**		39	39	39	76	113	137	395	674	818	1,016	1,275	1,578	6,199
	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	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)			250	250	250	490	730	889	2,554	4,363	5,294	6,575	8,252	10,209	40,106
	a. 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	2,554	4,363	5,294	6,575	8,252	10,209	40,106

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$303,297	$35,483	$29,422	$41,640	$200,238	$240,000	$65,000	$190,000	$327,000	$350,000	$225,000	$2,007,079
	b. Clearings to Plant			0	0	0	0	0	0	0	1,170,000	0	0	0	0	
	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	1,170,000	1,170,000	1,170,000	1,170,000	1,170,000	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	(909)	(2,727)	(4,545)	(6,363)	(8,181)	
4	CWIP - Non-Interest Bearing		674,010	674,010	977,307	644,946	674,368	716,008	916,246	1,156,246	51,246	241,246	568,246	918,246	1,143,246	
5	Net Investment (Lines 2 + 3 + 4)		$674,010	674,010	977,307	644,946	674,368	716,008	916,246	1,156,246	1,220,337	1,408,519	1,733,701	2,081,883	2,305,065	
6	Average Net Investment			674,010	825,658	627,205	659,657	695,188	816,127	1,036,246	1,188,291	1,314,428	1,571,110	1,907,792	2,193,474	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.15%		6,268	7,679	5,833	6,135	6,465	7,590	9,637	11,051	12,224	14,611	17,742	20,399	$125,634
	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	1,762	2,020	2,235	2,671	3,243	3,729	22,966
	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	909	1,818	1,818	1,818	1,818	8,181
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	875	875	875	875	875	4,375
	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	11,399	14,855	17,152	19,975	23,678	26,821	(28,629)
	a. 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	11,399	14,855	17,152	19,975	23,678	26,821	(28,629)

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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		$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	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	
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	125,705	125,281	124,857	
6	Average Net Investment			129,733	129,309	128,885	128,461	128,037	127,613	127,189	126,765	126,341	125,917	125,493	125,069	
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	1,171	1,167	1,163	$14,220
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		221	220	219	218	218	217	216	216	215	214	213	213	2,600
	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	1,915	1,910	1,906	23,180
	a. 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	1,915	1,910	1,906	23,180

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exh. No. (LC-2)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			($85,614)	($2,804)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($88,418)
	b. Clearings to Plant			365,936	(2,804)	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	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	712,740	712,740	712,740	712,740	712,740	712,740	
3	Less: Accumulated Depreciation		(7,419)	(8,600)	(10,180)	(11,760)	(13,340)	(14,920)	(16,500)	(18,080)	(19,660)	(21,240)	(22,820)	(24,400)	(25,980)	
4	CWIP - Non-Interest Bearing		451,549	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$793,740	706,945	702,561	700,981	699,401	697,821	696,241	694,661	693,081	691,501	689,921	688,341	686,761	
6	Average Net Investment			750,342	704,753	701,771	700,191	698,611	697,031	695,451	693,871	692,291	690,711	689,131	687,551	
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	6,468	6,453	6,438	6,424	6,409	6,394	$78,135
	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	1,182	1,180	1,177	1,174	1,172	1,169	14,284
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.66%		1,181	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	18,561
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	494	494	494	494	494	5,930
	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	9,724	9,707	9,689	9,672	9,655	9,637	116,910
	a. 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	9,724	9,707	9,689	9,672	9,655	9,637	116,910

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$23,085	$3,657	$9,173	$10,216	$354,724	$285,856	$355,000	$235,000	$485,000	$530,000	$130,000	$240,000	$2,661,712
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	2,665,776	
	c. Retirements			0	0	0	0	0	0	0	0	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	2,665,776	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(2,588)	
4	CWIP - Non-Interest Bearing		4,064	27,149	30,806	39,980	50,196	404,920	690,776	1,045,776	1,280,776	1,765,776	2,295,776	2,425,776	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$4,064	27,149	30,806	39,980	50,196	404,920	690,776	1,045,776	1,280,776	1,765,776	2,295,776	2,425,776	2,663,188	
6	Average Net Investment			15,607	28,978	35,393	45,088	227,558	547,848	868,276	1,163,276	1,523,276	2,030,776	2,360,776	2,544,482	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		145	269	329	419	2,116	5,095	8,075	10,818	14,166	18,886	21,955	23,664	$105,937
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		27	49	60	77	387	931	1,476	1,978	2,590	3,452	4,013	4,326	19,366
	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	2,588	2,588
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	1,926	1,926
	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	9,551	12,796	16,756	22,338	25,968	32,504	129,817
	a. 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	9,551	12,796	16,756	22,338	25,968	32,504	129,817

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exh. No. (LC-2)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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		(16,270)	(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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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)	(16,203)	(17,011)	(17,819)	(18,627)	(19,435)	(20,243)	
4	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	274,095	273,287	272,479	271,671	270,863	270,055	
6	Average Net Investment			283,873	282,242	280,611	278,980	277,349	275,718	274,499	273,691	272,883	272,075	271,267	270,459	
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	2,553	2,545	2,538	2,530	2,523	2,515	$30,817
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		483	480	477	474	471	469	467	465	464	463	461	460	5,634
	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	(5,163)	3,995	3,987	3,978	3,969	3,960	45,061
	a. 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	(5,163)	3,995	3,987	3,978	3,969	3,960	45,061

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7 2 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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

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

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$403	$2,104	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$2,506**
	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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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 Program Detail Support - Project 7.2 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$4,593	$925	$384	$2,371	$20,457	$26,428	$7,300	$100	$100	$100	$100	$100	$62,959
	b. Clearings to Plant			314,950	925	384	2,371	20,457	26,428	7,300	100	100	100	100	100	
	c. Retirements			0	0	0	0	0	0	0	0	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	372,816	372,916	373,016	373,116	373,216	373,316	
3	Less: Accumulated Depreciation		0	(512)	(1,539)	(2,567)	(3,603)	(1,208)	(1,513)	(1,824)	(2,135)	(2,446)	(2,757)	(3,068)	(3,379)	
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	370,992	370,781	370,570	370,359	370,148	369,937	
6	Average Net Investment			312,397	314,387	314,014	314,360	326,453	350,941	367,497	370,886	370,675	370,464	370,253	370,042	
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	3,418	3,449	3,447	3,445	3,443	3,441	$38,660
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		531	534	534	534	563	597	625	631	630	630	629	629	7,067
	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	311	311	311	311	311	311	3,379
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	258	258	258	258	259	259	2,915
	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	4,612	4,649	4,646	4,644	4,642	4,640	52,021
	a. 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	4,612	4,649	4,646	4,644	4,642	4,640	52,021

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$21,336	$319	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,655
	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)		$325,637	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

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

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$3,101	$1,541	$3,877	$1,200	$0	$0	$100	$100	$100	$100	$100	$100	**$10,318**
	b. Clearings to Plant			374,942	1,541	3,877	1,200	0	0	100	100	100	100	100	100	
	c. Retirements			0	0	0	0	0	0	0	0	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	381,660	381,760	381,860	381,960	382,060	382,160	
3	Less: Accumulated Depreciation		0	(670)	(2,016)	(3,376)	(4,740)	(3,016)	(3,690)	(4,364)	(5,038)	(5,713)	(6,388)	(7,063)	(7,738)	
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	377,296	376,722	376,147	375,572	374,997	374,422	
6	Average Net Investment			373,057	374,370	375,725	376,902	377,682	378,207	377,583	377,009	376,434	375,859	375,284	374,709	
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	3,512	3,506	3,501	3,495	3,490	3,485	$42,008
	b. Debt Component (Line 6 x 2.57% x 1/12)	**2.04%**		634	636	639	641	649	643	642	641	640	639	638	637	7,679
	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	675	675	675	675	7,738
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	5,097	5,090	5,085	5,078	5,072	5,066	60,643
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			5,037	5,729	5,761	5,779	2,746	5,103	5,097	5,090	5,085	5,078	5,072	5,066	60,643

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
January 2008 through December 2008

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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$52,616	$0	$0	$0	$0	$0	$0	$52,616
	b. Clearings to Plant			0	0	0	0	15,150,677	101,267	496,302	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	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	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	
3	Less: Accumulated Depreciation		0	0	0	0	0	(21,401)	(64,488)	(108,977)	(153,466)	(197,955)	(242,444)	(286,933)	(331,422)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	(48,651)	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	15,129,277	15,138,805	15,639,269	15,594,780	15,550,291	15,505,802	15,461,313	15,416,824	
6	Average Net Investment			0	0	0	0	7,564,638	15,134,041	15,389,037	15,617,025	15,572,536	15,528,047	15,483,558	15,439,069	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	70,351	140,747	143,118	145,238	144,825	144,411	143,997	143,583	$1,076,270
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	12,860	25,728	26,161	26,549	26,473	26,398	26,322	26,246	196,737
	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	44,489	44,489	44,489	44,489	44,489	44,489	331,422
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	14,051	14,051	14,051	14,051	14,051	14,051	111,432
	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	118,130	223,170	227,819	230,327	229,838	229,349	228,859	228,369	1,715,861
	a. 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	227,819	230,327	229,838	229,349	228,859	228,369	1,715,861

For Project: CAIR/CAMR Crystal River AFUDC - Low Nox Burner CR4 (Project 7.4b)
(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	Estimated Jul-08	Estimated Aug-08	Estimated Sep-08	Estimated Oct-08	Estimated Nov-08	Estimated 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	5,279,189	
	c. Retirements			0	0	0	0	0	0	0	0	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	5,279,189	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(6,225)	
4	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	5,272,964	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	2,636,482	
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	24,519	$24,519
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	0	4,482	4,482
	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	6,225	6,225
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	4,710	4,710
	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	39,936	39,936
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	39,936	39,936

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

JANUARY 2009 - DECEMBER 2009
Calculation of the Projected Period Amount
January through December 2009
DOCKET NO. 080007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 18
COMPANY PEF, Inc. (Direct)
WITNESS Lori Cross (LC-3)
DATE 11-04-08

PROGRESS ENERGY FLORIDA

Form 42-1P

Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered
For the Projected Period
January 2009 through December 2009
(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)	$71,453,196	$2,605,512	$11,410,385	$5,411,736	$90,880,829
	b Projected Capital Projects (Form 42-3P, Lines 7 through 9)	6,666,668	0	7,173	35,354,187	42,028,028
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	$78,119,864	$2,605,512	$11,417,558	$40,765,923	$132,908,857
2	True-up for Estimated Over/(Under) Recovery for the current period January 2008 - December 2008 (Form 42-2E, Line 5 + 6 + 10)	(3,714,500)	(317,677)	(4,820,298)	(1,019,953)	($9,872,429)
3	Final True-up for the period January 2007 - December 2007 (Form 42-1A, Line 3)	768,966	376,351	3,677,169	733,884	$5,556,369
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2008 - December 2008 (Line 1 - Line 2 - Line 3)	$81,065,398	$2,546,839	$12,560,688	$41,051,993	$137,224,917
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$81,123,765	$2,548,672	$12,569,731	$41,081,550	$137,323,719

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Witness: Lori Cross
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2009 - DECEMBER 2009

Form 42-2P

O&M Activities
(in Dollars)

Line	Description	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected Dec -09	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$ 307,557	$3,690,681
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	261,713	261,713	261,713	261,713	261,713	261,713	261,713	261,713	261,713	261,713	261,713	261,713	3,140,557
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	1,010,000	1,209,000	1,215,000	1,043,000	974,000	575,000	382,500	399,500	653,500	690,000	159,500	-	8,311,000
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	44,500	49,500	59,500	54,500	49,500	49,500	39,500	44,500	74,500	336,500	159,500	139,500	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 and NOX Emissions Allowances - Energy	5,198,503	4,106,610	3,759,676	4,225,393	6,415,656	5,329,541	7,238,639	7,290,641	7,504,415	6,664,573	5,929,510	8,313,042	71,976,198
	6 Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	6a Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR/CAMR - Peaking	-	43,700	6,000	-	-	6,000	-	-	6,000	-	6,000	-	67,700
	7.4 CAIR/CAMR Crystal River AFUDC - Base	1,653	1,653	1,653	1,653	167,530	167,530	167,530	167,530	167,530	167,530	208,917	208,917	1,429,627
	7.4 CAIR/CAMR Crystal River AFUDC - Energy	-	-	-	-	332,793	332,793	332,793	332,793	332,793	332,793	332,793	332,793	2,662,344
	8 Arsenic Groundwater Standard - Base	5,000	5,000	8,053	8,594	8,594	8,594	8,594	8,594	8,594	2,684	2,684	2,684	77,669
	9 Sea Turtle - Coastal Street Lighting - Distrib	417	417	417	417	417	417	417	417	416	416	416	416	5,000
	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	4,360	8,720	8,720	8,720	8,720	0	0	0	0	8,720	8,720	0	56,680
2	Total of O&M Activities	6,833,703	5,993,870	5,628,289	5,911,547	8,526,480	7,872,832	9,573,430	9,647,432	10,151,206	8,772,485	7,377,310	9,566,622	$95,855,207
3	Recoverable Costs Allocated to Energy	5,202,863	4,115,330	3,766,396	4,234,113	6,757,169	5,662,334	7,571,432	7,623,434	7,837,208	7,006,086	6,271,023	8,645,835	74,695,222
4	Recoverable Costs Allocated to Demand - Transm	307,557	307,557	307,557	307,557	307,557	307,557	307,557	307,557	307,557	307,557	307,557	307,557	3,690,681
	Recoverable Costs Allocated to Demand - Distrib	1,272,130	1,471,130	1,477,130	1,305,130	1,236,130	837,130	644,630	661,630	915,629	952,129	421,629	262,129	11,456,557
	Recoverable Costs Allocated to Demand - Prod-Base	6,653	6,653	9,706	10,247	176,124	1,010,312	1,010,312	1,010,312	1,010,312	170,214	211,601	211,601	4,844,048
	Recoverable Costs Allocated to Demand - Prod-Intm	44,500	49,500	59,500	54,500	49,500	49,500	39,500	44,500	74,500	336,500	159,500	139,500	1,101,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Retail Energy Jurisdictional Factor	0.96271	0.95044	0.94936	0.95101	0.95758	0.95813	0.95978	0.95816	0.95592	0.95396	0.95370	0.96065	
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	
7	Jurisdictional Energy Recoverable Costs (A)	5,008,827	3,911,357	3,577,558	4,026,692	6,470,544	5,425,241	7,266,891	7,304,497	7,491,766	6,683,528	5,980,680	8,305,615	71,453,196
8	Jurisdictional Demand Recoverable Costs - Transm (B)	217,126	217,126	217,126	217,126	217,126	217,126	217,126	217,126	217,126	217,126	217,126	217,126	2,605,512
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,267,003	1,465,201	1,471,177	1,299,870	1,231,148	833,756	642,032	658,964	911,939	948,292	419,930	261,073	11,410,385
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	6,238	6,238	9,100	9,607	165,121	947,198	947,198	947,198	947,198	159,581	198,382	198,382	4,541,441
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	35,175	39,128	47,032	43,080	39,128	39,128	31,223	35,175	58,889	265,990	126,078	110,269	870,295
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$6,534,369	$5,639,050	$5,321,993	$5,596,375	$8,123,067	$7,462,449	$9,104,470	$9,162,960	$9,626,918	$8,274,517	$6,942,196	$9,092,465	$90,880,829

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

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No.____(LC-3)
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Form 42-3P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2009 - DECEMBER 2009
Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected Dec -09	End of Period Total
1	Description of Investment Projects (A)													
3	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$49,738	$51,771	$51,630	$51,492	$51,001	$50,511	$50,371	$50,229	$50,089	$49,950	$49,809	$49,667	$606,258
4.1	Above Ground Tank Secondary Containment - Peaking	117,607	119,396	119,303	123,919	127,429	132,729	135,467	134,157	137,275	137,895	137,638	137,377	1,560,192
4.2	Above Ground Tank Secondary Containment - Base	425	424	423	421	420	419	418	417	415	414	413	412	5,021
4.3	Above Ground Tank Secondary Containment - Intermediate	3,951	3,942	3,934	3,924	3,916	3,907	3,898	3,889	3,880	3,871	3,863	3,853	46,828
5	SO2/NOX Emissions Allowances - Energy	781,162	729,984	686,719	682,185	659,960	597,538	578,384	543,184	501,194	462,648	393,381	358,555	6,974,894
7.1	CAIR/CAMR Anclote- Intermediate	706	706	706	706	706	706	706	706	706	706	706	706	8,472
7.2	CAIR CT's - Peaking	26,097	26,055	26,016	25,974	25,933	25,894	25,852	25,812	25,772	25,731	25,689	25,651	310,476
7.3	CAMR Crystal River - Base	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	152,652
7.4	CAIR/CAMR Crystal River AFUDC - Base	302,994	302,400	301,806	301,210	1,308,890	2,213,500	2,235,514	2,248,685	2,263,116	2,280,982	8,047,183	13,197,881	35,004,161
9	Sea Turtle - Coastal Street Lighting -Distribution	468	486	516	542	559	590	616	632	663	689	705	736	7,202
10.1	Underground Storage Tanks-Base	2,373	2,369	2,363	2,358	2,353	2,347	2,343	2,338	2,333	2,327	2,323	2,318	28,145
10.2	Underground Storage Tanks-Intermediate	1,038	1,036	1,033	1,031	1,029	1,026	1,025	1,023	1,020	1,018	1,016	1,013	12,308
11	Modular Cooling Towers - Base	15,369	15,247	15,125	15,003	14,881	14,759	14,637	14,515	14,393	14,272	14,150	14,028	176,379
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	1,314,648	1,266,537	1,222,295	1,221,486	2,209,798	3,056,647	3,061,952	3,038,308	3,013,577	2,993,224	8,689,597	13,804,918	44,892,988
3	Recoverable Costs Allocated to Energy	781,162	729,984	686,719	682,185	659,960	597,538	578,384	543,184	501,194	462,648	393,381	358,555	6,974,894
	Recoverable Costs Allocated to Demand - Distribution	468	486	516	542	559	590	616	632	663	689	705	736	7,202
4	Recoverable Costs Allocated to Demand - Production - Base	333,882	333,161	332,438	331,713	1,339,265	2,243,746	2,265,633	2,278,676	2,292,978	2,310,716	8,076,790	13,227,360	35,366,358
	Recoverable Costs Allocated to Demand - Production - Intermediate	55,433	57,455	57,303	57,153	56,652	56,150	56,000	55,847	55,695	55,545	55,394	55,239	673,866
	Recoverable Costs Allocated to Demand - Production - Peaking	143,704	145,451	145,319	149,893	153,362	158,623	161,319	159,969	163,047	163,626	163,327	163,028	1,870,668
5	Retail Energy Jurisdictional Factor	0.96271	0.95044	0.94936	0.95101	0.95758	0.95813	0.95978	0.95816	0.95592	0.95396	0.95370	0.96065	
	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)	752,029	693,803	651,942	648,766	631,966	572,518	555,120	520,459	479,103	441,348	375,168	344,446	6,666,668
	Jurisdictional Demand Recoverable Costs - Distribution (B)	466	484	514	540	557	588	614	629	660	686	702	733	7,173
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	313,024	312,348	311,671	310,991	1,255,601	2,103,579	2,124,099	2,136,327	2,149,736	2,166,366	7,572,233	12,401,047	33,157,022
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	43,818	45,416	45,296	45,177	44,781	44,384	44,266	44,145	44,025	43,906	43,787	43,664	532,664
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	127,866	129,421	129,303	133,373	136,460	141,141	143,540	142,339	145,078	145,593	146,327	145,061	1,664,502
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,237,204	$1,181,472	$1,138,726	$1,138,847	$2,069,365	$2,862,210	$2,867,638	$2,843,899	$2,818,601	$2,797,899	$8,137,216	$12,934,950	$42,028,028

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. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No.___(LC-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected Dec -09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$60,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$60,000
	b. Clearings to Plant			1,072,894	0	0	0	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		$2,674,588	3,747,482	3,747,482	3,747,482	3,747,482	3,747,482	3,747,482	3,747,482	3,747,482	3,747,482	3,747,482	3,747,482	3,747,482	
3	Less: Accumulated Depreciation		($417,864)	(428,806)	(441,581)	(454,356)	(467,131)	(479,906)	(492,681)	(505,456)	(518,231)	(531,006)	(543,781)	(556,556)	(569,331)	
4	CWIP - Non-Interest Bearing		$1,012,894	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$3,269,619	3,318,676	3,305,901	3,293,126	3,280,351	3,267,576	3,254,801	3,242,026	3,229,251	3,216,476	3,203,701	3,190,926	3,178,151	
6	Average Net Investment			3,294,148	3,312,289	3,299,514	3,286,739	3,273,964	3,261,189	3,248,414	3,235,639	3,222,864	3,210,089	3,197,314	3,184,539	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		30,635	30,804	30,685	30,566	30,154	29,739	29,620	29,501	29,382	29,264	29,145	29,026	358,523
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		5,600	5,631	5,609	5,588	5,511	5,436	5,415	5,392	5,371	5,350	5,328	5,305	65,536
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Investment Expenses															
	a. Depreciation (C)			10,942	12,775	12,775	12,775	12,775	12,775	12,775	12,775	12,775	12,775	12,775	12,775	151,467
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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)			2,561	2,561	2,561	2,561	2,561	2,561	2,561	2,561	2,561	2,561	2,561	2,561	30,732
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			49,738	51,771	51,630	51,492	51,001	50,511	50,371	50,229	50,089	49,950	49,809	49,667	606,258
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			49,738	51,771	51,630	51,492	51,001	50,511	50,371	50,229	50,089	49,950	49,809	49,667	606,258
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	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			39,316	40,923	40,811	40,702	40,314	39,927	39,816	39,704	39,593	39,483	39,372	39,260	479,223
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$39,316	$40,923	$40,811	$40,702	$40,314	$39,927	$39,816	$39,704	$39,593	$39,483	$39,372	$39,260	$479,223

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 80% @ .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.
(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 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected Dec -09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$45,000	$190,000	$327,000	$350,000	$225,000	$25,000	$100,000	$75,000	$0	$0	$0	$1,337,000
	b. Clearings to Plant			0	1,143,246	0	0	0	1,138,755	0	0	200,000	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		$7,721,451	7,721,451	8,864,697	8,864,697	8,864,697	8,864,697	10,003,452	10,003,452	10,003,452	10,203,452	10,203,452	10,203,452	10,203,452	
3	Less: Accumulated Depreciation		($281,027)	(298,799)	(317,459)	(343,847)	(363,395)	(382,943)	(404,062)	(419,911)	(440,803)	(463,956)	(487,573)	(511,190)	(534,807)	
4	CWIP - Non-Interest Bearing		$1,145,000	1,145,000	46,754	236,754	563,754	913,754	(0)	25,000	125,000	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$8,585,424	$8,567,652	$8,593,992	$8,757,604	$9,065,056	$9,395,508	$9,599,389	$9,608,540	$9,687,648	$9,739,495	$9,715,878	$9,692,261	$9,668,644	
6	Average Net Investment			8,576,538	8,580,822	8,491,876	8,911,330	9,230,282	9,497,449	9,603,965	9,648,094	9,713,572	9,727,687	9,704,070	9,680,453	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		79,763	79,803	78,973	82,874	85,842	88,327	89,317	89,728	90,334	90,467	90,249	90,028	1,035,705
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		14,580	14,586	14,435	15,150	15,692	16,147	16,325	16,401	16,513	16,536	16,497	16,457	189,319
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			17,772	18,660	19,548	19,548	19,548	21,119	22,689	20,892	23,153	23,617	23,617	23,617	253,780
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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)			5,492	6,347	6,347	6,347	6,347	7,136	7,136	7,136	7,275	7,275	7,275	7,275	81,388
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			117,607	119,396	119,303	123,919	127,429	132,729	135,467	134,157	137,275	137,895	137,638	137,377	1,560,192
	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			117,607	119,396	119,303	123,919	127,429	132,729	135,467	134,157	137,275	137,895	137,638	137,377	1,560,192
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)			104,646	106,237	106,155	110,262	113,385	118,101	120,537	119,372	122,146	122,698	122,469	122,237	1,388,243
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$104,646	$106,237	$106,155	$110,262	$113,385	$118,101	$120,537	$119,372	$122,146	$122,698	$122,469	$122,237	$1,388,243

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 Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected 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 (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	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	-	-	-	-	-	-	-	-	-	-	-	-	
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 (B)	11.16%		240	239	238	237	236	235	234	233	232	231	230	229	2,814
	b. Debt Component (Line 6 x 2.04% 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 (C)			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 (D)			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)			425	424	423	421	420	419	418	417	415	414	413	412	5,021
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			425	424	423	421	420	419	418	417	415	414	413	412	5,021
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)			398	398	397	395	394	393	392	391	389	388	387	386	4,707
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$398	$398	$397	$395	$394	$393	$392	$391	$389	$388	$387	$386	$4,707

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 Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected 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 (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		($20,243)	(21,051)	(21,859)	(22,667)	(23,475)	(24,283)	(25,091)	(25,899)	(26,707)	(27,515)	(28,323)	(29,131)	(29,939)	
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)		$270,055	269,247	268,439	267,631	266,823	266,015	265,207	264,399	263,591	262,783	261,975	261,167	260,359	
6	Average Net Investment			269,651	268,843	268,035	267,227	266,419	265,611	264,803	263,995	263,187	262,379	261,571	260,763	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,508	2,500	2,493	2,485	2,478	2,470	2,463	2,455	2,448	2,440	2,433	2,425	29,598
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		458	457	456	454	453	452	450	449	447	446	445	443	5,410
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			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 (D)			177	177	177	177	177	177	177	177	177	177	177	177	2,124
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,951	3,942	3,934	3,924	3,916	3,907	3,898	3,889	3,880	3,871	3,863	3,853	46,828
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,951	3,942	3,934	3,924	3,916	3,907	3,898	3,889	3,880	3,871	3,863	3,853	46,828
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)			3,123	3,116	3,110	3,102	3,095	3,088	3,081	3,074	3,067	3,060	3,054	3,046	37,016
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$3,123	$3,116	$3,110	$3,102	$3,095	$3,088	$3,081	$3,074	$3,067	$3,060	$3,054	$3,046	$37,016

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 Projected Period Amount
JANUARY 2009 - DECEMBER 2009
Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected Dec -09	Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		**$10,158,539**	$9,689,541	$9,319,844	$8,962,500	$8,617,429	$8,140,709	$7,669,637	$7,185,004	$6,680,481	$6,205,524	$5,634,790	$5,181,518	$4,768,373	$4,768,373
	b. 25401FL Auctioned SO_2 Allowance		**($2,063,254)**	(2,051,459)	(2,039,664)	(2,027,869)	(2,016,074)	(2,331,231)	(2,272,729)	(2,214,226)	(2,155,724)	(2,097,222)	(2,038,719)	(1,980,217)	(1,921,714)	(1,921,714)
	c. 1581002 NOX Emission Allowance Inventory		**$65,518,858**	$60,777,357	$57,028,649	$53,614,523	$56,883,031	$50,698,763	$46,738,041	$48,054,908	$41,210,288	$41,282,952	$35,130,611	$29,595,871	$29,548,097	29,548,097
2	Total Working Capital		**$73,613,943**	68,415,440	64,308,830	60,549,154	63,484,386	56,508,240	52,134,950	53,025,686	45,735,045	45,391,255	38,726,682	32,797,172	32,394,756	32,394,756
3	Average Net Investment			71,014,691	66,362,135	62,428,992	62,016,770	59,996,313	54,321,595	52,580,318	49,380,365	45,563,150	42,058,969	35,761,927	32,595,964	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		660,437	617,168	580,590	576,756	557,966	505,191	488,997	459,237	423,737	391,148	332,586	303,142	$5,896,955
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		120,725	112,816	106,129	105,429	101,994	92,347	89,387	83,947	77,457	71,500	60,795	55,413	1,077,939
5	Total Return Component (B)			781,162	729,984	686,719	682,185	659,960	597,538	578,384	543,184	501,194	462,648	393,381	358,555	6,974,894
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			$468,998	$369,697	$357,344	$345,071	$476,720	$471,071	$484,633	$504,524	$474,957	$570,734	$453,272	$413,145	5,390,166
	b. 4074004 Amortization Expense			($11,795)	($11,795)	($11,795)	($11,795)	($245,332)	($58,502)	($58,502)	($58,502)	($58,502)	($58,502)	($58,502)	($58,502)	($702,029)
	c. 5090003 Nox allowance expense			4,741,300	3,748,708	3,414,126	3,892,117	6,184,268	4,916,972	6,812,508	6,844,619	7,087,961	6,152,341	5,534,740	7,958,399	$67,288,060
7	Net Expense (C)			5,198,503	4,106,610	3,759,676	4,225,393	6,415,656	5,329,541	7,238,639	7,290,641	7,504,415	6,664,573	5,929,510	8,313,042	71,976,198
8	Total System Recoverable Expenses (Lines 5 + 7)			5,979,665	4,836,594	4,446,395	4,907,578	7,075,616	5,927,079	7,817,023	7,833,825	8,005,609	7,127,221	6,322,891	8,671,597	78,951,092
	a. Recoverable costs allocated to Energy			5,979,665	4,836,594	4,446,395	4,907,578	7,075,616	5,927,079	7,817,023	7,833,825	8,005,609	7,127,221	6,322,891	8,671,597	78,951,092
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96271	0.95044	0.94936	0.95101	0.95758	0.95813	0.95978	0.95816	0.95592	0.95396	0.95370	0.96065	
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)			5,756,659	4,596,872	4,221,222	4,667,165	6,775,484	5,678,900	7,502,604	7,506,086	7,652,744	6,799,086	6,030,147	8,330,363	75,517,332
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)			$ 5,756,659	$ 4,596,872	$ 4,221,222	$ 4,667,165	$ 6,775,484	$ 5,678,900	$ 7,502,604	$ 7,506,086	$ 7,652,744	$ 6,799,086	$ 6,030,147	$ 8,330,363	$ 75,517,332

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 Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected 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 (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		$64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	
	5 Net Investment (Lines 2 + 3 + 4)		$64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	
	6 Average Net Investment			64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	
	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	597	$7,164
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		109	109	109	109	109	109	109	109	109	109	109	109	1,308
	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	706	8,472
	a. 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	706	8,472
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	558	6,697
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$6,697

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 Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected 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 (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	1,962,826	
3	Less: Accumulated Depreciation		($47,306)	(50,985)	(54,664)	(58,343)	(62,022)	(65,701)	(69,380)	(73,059)	(76,738)	(80,417)	(84,096)	(87,775)	(91,454)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,915,521	1,911,842	1,908,163	1,904,484	1,900,805	1,897,126	1,893,447	1,889,768	1,886,089	1,882,410	1,878,731	1,875,052	1,871,373	
6	Average Net Investment			1,913,682	1,910,003	1,906,324	1,902,645	1,898,966	1,895,287	1,891,608	1,887,929	1,884,250	1,880,571	1,876,892	1,873,213	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,798	17,763	17,729	17,694	17,659	17,627	17,592	17,557	17,524	17,489	17,454	17,422	211,308
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,254	3,247	3,242	3,235	3,229	3,222	3,215	3,210	3,203	3,197	3,190	3,184	38,628
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			3,679	3,679	3,679	3,679	3,679	3,679	3,679	3,679	3,679	3,679	3,679	3,679	44,148
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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)			1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	16,392
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			26,097	26,055	26,016	25,974	25,933	25,894	25,852	25,812	25,772	25,731	25,689	25,651	310,476
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			26,097	26,055	26,016	25,974	25,933	25,894	25,852	25,812	25,772	25,731	25,689	25,651	310,476
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)			23,221	23,183	23,149	23,111	23,075	23,040	23,003	22,967	22,932	22,895	22,858	22,824	276,258
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$23,221	$23,183	$23,149	$23,111	$23,075	$23,040	$23,003	$22,967	$22,932	$22,895	$22,858	$22,824	$276,258

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

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No. ____(LC-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected 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 (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		$1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	
5	Net Investment (Lines 2 + 3 + 4)		$1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	
6	Average Net Investment			1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	1,156,453	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		10,755	10,755	10,755	10,755	10,755	10,755	10,755	10,755	10,755	10,755	10,755	10,755	$129,060
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	23,592
	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)			12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	152,652
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	12,721	152,652
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 (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)			11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926	143,116
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$11,926	$11,926	$11,926	$11,926	$11,926	$11,926	$11,926	$11,926	$11,926	$11,926	$11,926	$11,926	$143,116

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 Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected Dec -09	End of Period Total
1	Investments															
	a. Expenditures/Additions			23,252,014	22,760,102	18,106,129	17,201,145	15,910,314	15,841,656	14,160,694	13,299,127	20,110,310	19,609,765	19,497,407	16,147,172	$215,895,835
	b. Clearings to Plant			2,234	2,234	2,234	2,234	133,285,281	2,013,928	1,725,481	899,658	1,566,371	1,544,824	761,378,709	11,383,533	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)	8.848%		5,895,913	6,187,575	6,431,580	6,640,277	6,371,682	6,070,087	6,222,253	6,367,489	6,505,736	6,639,901	4,238,794	1,717,710	69,288,997
2	Plant-in-Service/Depreciation Base		$21,027,435	21,029,669	21,031,903	21,034,137	21,036,371	154,321,652	156,335,580	158,061,061	158,960,719	160,527,090	162,071,914	923,450,622	934,834,155	
3	Less: Accumulated Depreciation		($337,647)	(394,591)	(451,541)	(508,496)	(565,456)	(779,584)	(1,155,625)	(1,535,735)	(1,917,967)	(2,303,893)	(2,693,462)	(3,983,062)	(5,182,199)	
4	CWIP - AFUDC-Interest Bearing		$883,920,360	913,066,053	942,011,496	966,546,971	990,386,158	879,392,873	899,280,689	917,938,155	936,705,112	961,754,788	986,459,630	248,817,122	255,298,471	285,184,831
5	Net Investment (Lines 2 + 3 + 4)		$904,610,148	933,701,132	962,591,858	987,072,612	1,010,857,074	1,032,924,942	1,054,460,644	1,074,463,481	1,093,747,865	1,119,977,985	1,145,838,082	1,168,284,683	1,183,950,428	
6	Average Net Investment			919,155,640	948,146,495	974,832,235	998,964,843	1,021,891,008	1,043,692,793	1,064,462,063	1,084,105,673	1,106,862,925	1,132,908,033	1,157,061,382	1,176,117,555	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		192,161	191,652	191,143	190,634	809,161	1,435,558	1,449,429	1,458,091	1,485,987	1,476,847	5,016,634	8,593,755	22,471,052
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		35,126	35,033	34,941	34,847	147,911	262,414	264,949	266,533	267,976	269,961	917,019	1,570,902	4,107,612
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			56,944	56,950	56,955	56,960	214,128	376,041	380,110	382,232	385,926	389,569	1,289,600	2,199,137	5,844,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			18,763	18,765	18,767	18,769	137,690	139,487	141,026	141,829	143,227	144,605	823,930	834,087	2,580,945
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			302,994	302,400	301,806	301,210	1,308,890	2,213,500	2,235,514	2,248,685	2,283,116	2,280,982	8,047,183	13,197,881	35,004,161
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			302,994	302,400	301,806	301,210	1,308,890	2,213,500	2,235,514	2,248,685	2,283,116	2,280,982	8,047,183	13,197,881	35,004,161
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			284,066	283,509	282,952	282,393	1,227,124	2,075,223	2,095,861	2,108,210	2,121,739	2,138,489	7,544,475	12,373,409	32,817,451
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$284,066	$283,509	$282,952	$282,393	$1,227,124	$2,075,223	$2,095,861	$2,108,210	$2,121,739	$2,138,489	$7,544,475	$12,373,409	$32,817,451

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 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 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 2007 Effective Tax Rate on original cost.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected Dec -09	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		$29,701	29,701	29,701	34,701	34,701	34,701	39,701	39,701	39,701	44,701	44,701	44,701	49,701	
3	Less: Accumulated Depreciation		($361)	(475)	(589)	(713)	(846)	(979)	(1,121)	(1,273)	(1,425)	(1,587)	(1,758)	(1,929)	(2,109)	
4	CWIP - Non-Interest Bearing		$0	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)		$29,340	30,893	32,445	33,989	35,522	37,056	38,580	40,095	41,609	43,114	44,610	46,106	47,592	
6	Average Net Investment			30,116	31,669	33,217	34,755	36,289	37,818	39,337	40,852	42,362	43,862	45,358	46,849	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		280	295	309	323	337	352	366	380	394	408	422	436	$4,302
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		51	54	56	59	62	64	67	69	72	75	77	80	786
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	4.59%		114	114	124	133	133	143	152	152	162	171	171	181	1,748
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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		23	23	27	27	27	31	31	31	35	35	35	39	364
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			468	486	516	542	559	590	616	632	663	689	705	736	7,202
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			468	486	516	542	559	590	616	632	663	689	705	736	7,202
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)			466	484	514	540	557	588	614	629	660	686	702	733	7,173
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$466	$484	$514	$540	$557	$588	$614	$629	$660	$686	$702	$733	$7,173

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 Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected 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 (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	3,217
	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)			2,373	2,369	2,363	2,358	2,353	2,347	2,343	2,338	2,333	2,327	2,323	2,318	28,145
	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			2,373	2,369	2,363	2,358	2,353	2,347	2,343	2,338	2,333	2,327	2,323	2,318	28,145
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)			2,225	2,221	2,215	2,211	2,206	2,200	2,197	2,192	2,187	2,182	2,178	2,173	26,387
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,225	$2,221	$2,215	$2,211	$2,206	$2,200	$2,197	$2,192	$2,187	$2,182	$2,178	$2,173	$26,387

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

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No.___(LC-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected 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 (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	$7,818
	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	1,430
	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)		1,038	1,036	1,033	1,031	1,029	1,026	1,025	1,023	1,020	1,018	1,016	1,013	12,308
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,038	1,036	1,033	1,031	1,029	1,026	1,025	1,023	1,020	1,018	1,016	1,013	12,308
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)		820	819	817	815	813	811	810	809	806	805	803	801	9,729
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$820	$819	$817	$815	$813	$811	$810	$809	$806	$805	$803	$801	$9,729

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 Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected 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 (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)		$340,993	329,907	318,821	307,735	296,649	285,563	274,477	263,391	252,305	241,219	230,133	219,047	207,961	
6	Average Net Investment			335,450	324,364	313,278	302,192	291,106	280,020	268,934	257,848	246,762	235,676	224,590	213,504	
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			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)	0.010707		593	593	593	593	593	593	593	593	593	593	593	593	7,116
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			15,369	15,247	15,125	15,003	14,881	14,759	14,637	14,515	14,393	14,272	14,150	14,028	176,379
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			15,369	15,247	15,125	15,003	14,881	14,759	14,637	14,515	14,393	14,272	14,150	14,028	176,379
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)			14,409	14,295	14,180	14,066	13,951	13,837	13,723	13,608	13,494	13,380	13,266	13,152	165,361
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$14,409	$14,295	$14,180	$14,066	$13,951	$13,837	$13,723	$13,608	$13,494	$13,380	$13,266	$13,152	$165,361

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

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No.___(LC-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2009 - 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	Projected Jan - 09	Projected Feb -09	Projected Mar - 09	Projected Apr - 09	Projected May - 09	Projected Jun -09	Projected Jul - 09	Projected Aug - 09	Projected Sep - 09	Projected Oct -09	Projected Nov -09	Projected Dec -09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$429,271	$39,455	$2,833,806	$854,048	$983,367	$689,266	$1,233,961	$335,029	$1,430,057	$346,930	$2,120,176	$304,440	$11,599,807
	b. Clearings to Plant			0	0	0	0	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)			$ 152	$ 318	$ 2,707	$ 5,509	$ 15,328	$ 27,687	$ 34,231	$ 40,124	$ 46,885	$ 52,521	$ 59,027	$ 65,556	$350,046
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		$0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - AFUDC- Interest Bearing		$0	429,271	468,726	3,302,532	4,156,580	5,139,948	5,829,214	7,063,175	7,398,204	8,828,261	9,175,191	11,295,366	11,599,807	
5	Net Investment (Lines 2 + 3 + 4)		$0	429,271	468,726	3,302,532	4,156,580	5,139,948	5,829,214	7,063,175	7,398,204	8,828,261	9,175,191	11,295,366	11,599,807	
6	Average Net Investment			214,636	448,999	1,885,629	3,729,556	4,648,264	5,484,581	6,446,194	7,230,689	8,113,232	9,001,726	10,235,279	11,447,587	
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			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)			0.93753	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 (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 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 9a x Line 10
(D) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
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 40 substations during 2008. PEF is currently on target to meet the schedule for substation remediations agreed to with the FDEP for 2008.

Project Fiscal Expenditures:
January 1, 2008 to December 31, 2008: Project expenditures are estimated to be $2,736,930 higher than originally projected. This variance is primarily due to higher than expected remediation costs at several substation sites.

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 2009 through December 2009 are expected to be $6,831,238.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
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 conducted environmental inspections on 9,659 sites during 2008. In addition, Progress Energy is expecting to complete remediations on 1,136 distribution padmount transformer sites in 2008. All remediations have been conducted in accordance with the FDEP approved Environmental Remediation Strategy.

Project Fiscal Expenditures:
January 1, 2008 to December 31, 2008: Project expenditures are estimated to be $427,507 higher than originally projected. This variance is primarily due to a higher number of sites being remediated than originally anticipated in the 2008 work plan, including carryover from the 2007 work plan.

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 2009 through December 2009 are expected to be approximately $8 million. Progress Energy is expecting to complete remediations on approximately 900 sites.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

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 2008, PEF continued work on the PIM program. This effort included ongoing activities as required by the integrity management regulation as well as projects to address protection of valve mechanisms along U.S. Highway 19 and remote control of valves designed to isolate sections of the pipeline in the event of a leak.

Project Fiscal Expenditures:
January 1, 2008 to December 31, 2008: O&M project expenditures are estimated to be $146,057 higher than originally projected. This variance is due to an increase in the scope of work. An additional $332,707 in capital costs were incurred due to higher than expected costs for the installation of the Pipeline Controls upgrade project.

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 2008, and into the future.

Project Projections:
Estimated project O&M expenditures for the period January 2009 through December 2009 are expected to be $1,101,000; estimated capital expenditure for the period are expected to be $60,000.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

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:
Activities during 2007 included continued work on above ground storage tank systems at Debary, Turner 7, and Turner 8.

Project Fiscal Expenditures:
January 1, 2008 to December 31, 2008: O&M project expenditures are estimated to be $368,303 higher than original projection due to costs for additional work necessary to bring Turner Tank 8 into compliance with secondary containment requirement. Capital project expenditures will be approximately $1,809,738 higher than the original projection due to the upgrades of two tanks at the Turner combustion turbine facility.

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 2009 through December 2009 are expected to be approximately $1.3 million. The costs are associated with work at the Bartow and Higgins combustion turbine sites.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **SO_2 and NOXEmissions**
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, 2008 to December 31, 2008: Project expenditures are estimated to be $1,649,557 lower than originally projected. This variance is primarily driven by a decrease in projected tons of emissions attributable to lower SO2 content in fuel, as well as lower projected energy requirements. There were no NOX allowance expenditures in 2008 as they will not take effect until 2009.

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:
Estimated SO2 and NOX project expenditures for the period January 2009 through December 2009 are expected to be $4,688,137 and $67,288,060, respectively.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

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 to FDEP. FDEP approved all the PICs, and field work is now underway.

Project Fiscal Expenditures:
January 2008 - December 2008: PEF's projected expenditures will be approximately $38,128 less than the original projection for 2008. This variance is primarily attributable to lower than expected costs to complete reports summarizing the results of the completed biological studies. Work has been suspended on the project pending completion of additional rulemaking by the U.S. Environmental Protection Agency (EPA) in response to the Second U.S. Circuit Court of Appeals' vacatur of the Phase II cooling water intake rules.

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 2009 through December 2009 are projected to be $0.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **CAIR and CAMR**
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. The Clean Air Mercury Rule (CAMR), 40 CFR Part 60 Subpart Da and 40 CFR Part 60 Subpart HHHH, employs a cap on total mercury emissions from coal-fired power plants in order to achieve significant emissions reductions. Mercury emissions from new and existing coal-fired utility units will be capped at specified nationwide levels.

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

Project Fiscal Expenditures:
January 2008 - December 2008: PEF's expenditures for the Crystal River Projects in 2008 will be approximately $527 million, which is approximately $42 million less than projected in last year's docket. Of this difference, approximately $12 million is attributable to the fact that last year's projections were based on contract prices that were not finalized until PEF executed the Engineering Procurement and Construction (EPC) contract for the Project after the projects were submitted. The remaining variance is attributable to work on particulate controls for which PEF is no longer requesting ECRC recovery.

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 2009 through December 2009 are expected to be approximately $215.9 million relating to the SCR and FGD systems at both Crystal River Units 4 and 5.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

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 groundwater monitoring plan. As results are gathered and submitted to FDEP, PEF will be able to determine future compliance activities and costs. The industrial wastewater permit, including the groundwater monitoring plan, was issued on January 9, 2007.

Project Fiscal Expenditures:
January 2008 - December 2008: 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:
Estimated project expenditures for the period January 2009 through December 2009 are expected to be $77,669 for analytical testing and consultant costs associated with development of compliance strategies. These strategies will depend upon analytical results and discussions with FDEP.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Sea Turtle - Coastal Street Lighting**
Project No. 9

Project Description:
PEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the Florida Department of Environmental Protection (FDEP), in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. The model ordinance is used by the local governments to develop and implement 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, 2008 to December 31, 2008: Project revenue requirements are estimated to be $175,165 lower than originally projected due to lower costs of the joint study performed with the University of Florida.

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

Project Projections:
Estimated project expenditures for the period January 2009 through December 2009 are expected to be $5,000 in O&M costs and $20,000 in capital expenditures to ensure ongoing compliance with sea turtle ordinances.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

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 2008.

Project Projections:
No project capital expenditures are anticipated for the period January 2009 through December 2009.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

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 Cyrstal 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 $3.4 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 $3.4 million for the period January 2009 thru December 2009.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2009 - DECEMBER 2009
Description and Progress Report for
Environmental Compliance Activities and Projects

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 best way to accomplish the recommendation is being evaluated.

Project Fiscal Expenditures:
$0 was projected to be spent in 2008.

Project Progress Summary:
The conceptual design is complete. The final design contract offering is being prepared and is expected to be issued this year.

Project Projections:
Estimated project expenditures are expected to be approximately $11.9 million for the period January 2009 thru December 2009.

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calculation of the Energy & Demand Allocation % by Rate Class

January - December 2009

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)/(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	0.550	20,542,747	4,263.75	0.395	0.9361264	21,944,416	4,554.67	21,944,416	6,342.0	51.197%	60.673%	59.944%	62.872%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.658	1,331,707	231.04	0.453	0.9361264	1,422,572	246.80	1,422,572	358.5	3.319%	3.288%	3.290%	3.554%
Primary	0.658	9,005	1.56	0.453	0.9679458	9,303	1.61	9,303	2.3	0.022%	0.021%	0.022%	0.023%
Transmission	0.658	3,360	0.58	0.453	0.9779458	3,436	0.60	0	0.0	0.008%	0.008%	0.008%	0.000%
										3.349%	3.317%	3.319%	3.577%
General Service													
GS-2 Secondary	1.000	89,624	10.23	1.000	0.9361264	95,739	10.93	95,739	10.9	0.223%	0.146%	0.152%	0.108%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.789	13,080,248	1,892.50	0.634	0.9679458	13,513,410	1,955.17	13,513,410	2,433.2	31.527%	26.045%	26.466%	24.122%
Primary	0.789	2,484,990	359.54	0.634	0.9679458	2,567,282	371.44	2,567,282	462.3	5.990%	4.948%	5.028%	4.583%
Transmission	0.789	0	0.00	0.634	0.9779458	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.264	0	0.00	0.173	0.9779458	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.264	9,831	0.89	0.173	0.9779458	10,053	0.91	0	0.0	0.023%	0.012%	0.013%	0.000%
Transm Del/ Primary Mtr	1.264	5,414	0.49	0.173	0.9679458	5,593	0.51	0	0.0	0.013%	0.007%	0.007%	0.000%
										37.553%	31.011%	31.515%	28.704%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	1.093	0	0.00	0.720	0.9361264	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	1.093	189,554	19.80	0.720	0.9679458	195,831	20.45	195,831	31.0	0.457%	0.272%	0.287%	0.308%
SS-3 Primary	∞	2,009	0.00	0.047	0.9679458	2,076	0.00	2,076	5.0	0.005%	0.000%	0.000%	0.050%
										0.462%	0.272%	0.287%	0.358%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.927	1,468,420	180.83	0.710	0.9361264	1,568,613	193.17	1,568,613	252.2	3.660%	2.573%	2.657%	2.500%
Primary Del / Primary Mtr	0.927	273,737	33.71	0.710	0.9679458	282,802	34.83	282,802	45.5	0.660%	0.464%	0.479%	0.451%
Primary Del / Transm Mtr	0.927	317,529	39.10	0.710	0.9779458	324,690	39.98	324,690	52.2	0.758%	0.533%	0.550%	0.518%
Transm Del/ Transm Mtr	0.927	311,416	38.35	0.710	0.9779458	318,439	39.21	0	0.0	0.743%	0.522%	0.539%	0.000%
Transm Del/ Primary Mtr	0.927	74,064	9.12	0.710	0.9679458	76,517	9.42	0	0.0	0.179%	0.126%	0.130%	0.000%
SS-2 Primary	0.749	0	0.00	0.263	0.9679458	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.749	71,930	10.96	0.263	0.9779458	73,552	11.21	0	0.0	0.172%	0.149%	0.151%	0.000%
Transm Del/ Primary Mtr	0.749	60,528	9.23	0.263	0.9679458	62,532	9.53	0	0.0	0.146%	0.127%	0.128%	0.000%
										6.316%	4.494%	4.634%	3.469%
Lighting													
LS-1 (Secondary)	6.746	361,353	6.11	0.479	0.9361264	386,009	6.53	386,009	92.0	0.901%	0.087%	0.150%	0.912%
		40,687,466	7,107.78			42,862,864	7,506.97	42,312,742	10,087.1	100.000%	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2006
(2) Projected kWh sales for the period January 2007 to December 2007
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2006
(5) Based on system average line loss analysis for 2005
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,760 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No.___(LC-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 2009 through December 2009

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Demand Transmission Allocator (%)	(3) 12CP & 1/13 AD Demand Allocator (%)	(4) NCP Distribution Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	(11) Environmental Cost Recovery Factors (cents/kWh)
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1											
Secondary	51.197%	60.673%	59.944%	62.872%	$41,532,774	$1,546,345	$7,902,835	$24,625,784	$75,607,738	20,542,747	0.368
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,331,707	0.343
Primary										8,915	0.340
Transmission										3,293	0.336
TOTAL GS	3.349%	3.317%	3.319%	3.577%	$2,716,520	$84,541	$449,638	$1,363,690	$4,614,388	1,343,915	
General Service											
GS-2 Secondary	0.223%	0.146%	0.152%	0.108%	$181,199	$3,711	$13,619	$62,267	$260,796	89,624	0.291
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										13,080,248	0.307
Primary										2,465,500	0.304
Transmission										9,634	0.301
TOTAL GSD	37.553%	31.011%	31.515%	28.704%	$30,464,495	$790,381	$3,608,041	$12,946,718	$47,809,635	*15,555,382*	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	0.287
Primary										189,647	0.284
Transmission										-	0.281
TOTAL CS	0.462%	0.272%	0.287%	0.358%	$374,565	$6,944	$44,972	$117,909	$544,391	189,647	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										1,468,420	0.296
Primary										404,246	0.293
Transmission										686,858	0.290
TOTAL IS	6.316%	4.494%	4.634%	3.469%	$5,123,638	$114,534	$435,991	$1,903,727	$7,577,889	2,559,523	
Lighting											
LS-1 Secondary	0.901%	0.087%	0.150%	0.912%	$730,574	$2,218	$114,635	$61,455	$908,882	361,353	0.252
	100.000%	100.000%	100.000%	100.000%	$81,123,765	$2,548,672	$12,569,731	$41,081,550	$137,323,719	40,642,192	0.338

Notes:

(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 10
(3) From Form 42-6P, Column 11
(4) From Form 42-6P, Column 12
(5) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(6) Column 2 x Total Transmission Demand Jurisdictional Dollars from Form 42-1P, line 5
(7) Column 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 3 x Total Production Demand Jurisdictional Dollars from Form 42-1P, line 5
(9) Column 5 + Column 6 + Column 7 + Column 8
(10) Projected kWh sales at effective voltage level for the period January 2007 to December 2007
(11) Column 7/ Column 8 x 100

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

JANUARY 2009 - DECEMBER 2009
Calculation of the Projected Period Amount
January through December 2009
DOCKET NO. 080007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 19
COMPANY PEF, Inc. (Direct)
WITNESS Lori Cross (LC-4)
DATE 11-04-08

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2009 - DECEMBER 2009

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

Intermediate

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	0.008202		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)

Intermediate

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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)	(521,983)	(531,005)	(540,027)	(549,049)	(558,071)	(567,093)	(576,115)	(585,137)	
4	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	2,118,653	2,109,631	2,100,609	2,091,587	2,082,565	2,073,543	2,064,521	2,055,499	
6	Average Net Investment			2,222,714	2,213,692	2,204,670	2,195,648	2,154,895	2,114,142	2,105,120	2,096,098	2,087,076	2,078,054	2,069,032	2,060,010	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		20,671	20,587	20,503	20,420	20,041	19,662	19,578	19,494	19,410	19,326	19,242	19,158	$238,092
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,779	3,763	3,748	3,733	3,663	3,594	3,579	3,563	3,548	3,533	3,517	3,502	43,522
	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	0.008202		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	34,531	34,083	33,984	33,884	33,785	33,686	33,586	33,487	411,538
	a. 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	34,531	34,083	33,984	33,884	33,785	33,686	33,586	33,487	411,538

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2009 - DECEMBER 2009

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

Intermediate

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$60,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$60,000**
	b. Clearings to Plant			1,072,894	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	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	1,072,894	1,072,894	1,072,894	1,072,894	1,072,894	1,072,894	1,072,894	1,072,894	1,072,894	1,072,894	1,072,894	1,072,894	
3	Less: Accumulated Depreciation		$0	(1,833)	(5,499)	(9,165)	(12,831)	(16,497)	(20,163)	(23,829)	(27,495)	(31,161)	(34,827)	(38,493)	(42,159)	
4	CWIP - Non-Interest Bearing		$1,012,894	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,012,894	1,071,061	1,067,395	1,063,729	1,060,063	1,056,397	1,052,731	1,049,065	1,045,399	1,041,733	1,038,067	1,034,401	1,030,735	
6	Average Net Investment			1,041,977	1,069,228	1,065,562	1,061,896	1,058,230	1,054,564	1,050,898	1,047,232	1,043,566	1,039,900	1,036,234	1,032,568	
7	Return on Average Net Investment															
	a Equity Component Grossed Up For Taxes	**11.16%**		9,690	9,944	9,910	9,876	9,842	9,807	9,773	9,739	9,705	9,671	9,637	9,603	$117,197
	b. Debt Component (Line 6 x 2.04% x 1/12)	**2.04%**		1,771	1,818	1,811	1,805	1,799	1,793	1,787	1,780	1,774	1,768	1,762	1,755	21,423
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	**4.10%**		1,833	3,666	3,666	3,666	3,666	3,666	3,666	3,666	3,666	3,666	3,666	3,666	42,159
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	**0.008202**		733	733	733	733	733	733	733	733	733	733	733	733	8,796
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,027	16,161	16,120	16,080	16,040	15,999	15,959	15,918	15,878	15,838	15,798	15,757	189,575
	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			14,027	16,161	16,120	16,080	16,040	15,999	15,959	15,918	15,878	15,838	15,798	15,757	189,575

Docket No. 080007-EI
Progress Energy Florida
Witness: Lori Cross
Exhibit No.____(LC-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2009 - DECEMBER 2009

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

Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	1,143,246	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,170,000	1,170,000	2,313,246	2,313,246	2,313,246	2,313,246	2,313,246	2,313,246	2,313,246	2,313,246	2,313,246	2,313,246	2,313,246	
3	Less: Accumulated Depreciation		($8,181)	(9,999)	(12,705)	(16,299)	(19,883)	(23,487)	(27,081)	(30,675)	(32,472)	(36,066)	(39,660)	(43,254)	(46,848)	
4	CWIP - Non-Interest Bearing		$1,143,246	1,143,246	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$2,305,065	2,303,247	2,300,541	2,296,947	2,293,353	2,289,759	2,286,165	2,282,571	2,280,774	2,277,180	2,273,586	2,269,992	2,266,398	
6	Average Net Investment			2,304,156	2,301,894	2,114,822	2,295,150	2,291,556	2,287,962	2,284,368	2,281,672	2,278,977	2,275,383	2,271,789	2,268,195	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		21,429	21,408	19,668	21,345	21,311	21,278	21,245	21,220	21,194	21,161	21,128	21,094	$253,481
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		3,917	3,913	3,595	3,902	3,896	3,890	3,883	3,879	3,874	3,868	3,862	3,856	46,335
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.86%		1,818	2,706	3,594	3,594	3,594	3,594	3,594	1,797	3,594	3,594	3,594	3,594	38,667
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008974		875	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	19,905
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			28,039	29,757	28,587	30,571	30,531	30,492	30,452	28,626	30,392	30,353	30,314	30,274	358,388
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			28,039	29,757	28,587	30,571	30,531	30,492	30,452	28,626	30,392	30,353	30,314	30,274	358,388

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

Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$45,000	$190,000	$327,000	$350,000	$225,000	$0	$0	$0	$0	$0	$0	$1,137,000
	b. Clearings to Plant			0	0	0	0	0	1,138,755	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	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	1,292,453	1,292,453	1,292,453	1,292,453	1,292,453	1,292,453	1,292,453	
3	Less: Accumulated Depreciation		($30,596)	(31,020)	(31,444)	(31,868)	(32,292)	(32,716)	(34,710)	(38,275)	(41,840)	(45,405)	(48,970)	(52,535)	(56,100)	
4	CWIP - Non-Interest Bearing		$1,755	1,755	46,755	236,755	563,755	913,755	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$124,857	124,433	169,009	358,585	685,161	1,034,737	1,257,743	1,254,178	1,250,613	1,247,048	1,243,483	1,239,918	1,236,353	
6	Average Net Investment			124,645	146,721	263,797	521,873	859,949	1,146,240	1,255,960	1,252,395	1,248,830	1,245,265	1,241,700	1,238,135	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,159	1,365	2,453	4,853	7,998	10,660	11,680	11,647	11,614	11,581	11,548	11,515	$98,073
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		212	249	448	887	1,462	1,949	2,135	2,129	2,123	2,117	2,111	2,105	17,927
	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	1,995	3,565	3,565	3,565	3,565	3,565	3,565	25,505
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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	895	895	895	895	895	895	895	6,795
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,901	2,144	3,431	6,270	9,990	15,499	18,275	18,236	18,197	18,158	18,119	18,080	148,300
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,901	2,144	3,431	6,270	9,990	15,499	18,275	18,236	18,197	18,158	18,119	18,080	148,300

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2009 - DECEMBER 2009

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

Base

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	0.010707		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)			425	424	423	421	420	419	418	417	415	414	413	412	5,021
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			425	424	423	421	420	419	418	417	415	414	413	412	5,021

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

Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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)	(140,717)	(145,411)	(150,105)	(154,799)	(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	1,520,947	1,516,253	1,511,559	1,506,865	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	1,526,714	1,518,600	1,513,906	1,509,212	1,507,938	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	14,198	14,123	14,079	14,036	14,024	14,012	13,968	13,925	13,881	13,837	$168,675
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		2,617	2,609	2,595	2,582	2,574	2,566	2,563	2,561	2,553	2,545	2,537	2,529	30,831
	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)			22,683	22,631	22,541	22,453	22,401	22,350	22,335	22,321	22,269	22,218	22,166	22,114	268,482
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			22,683	22,631	22,541	22,453	22,401	22,350	22,335	22,321	22,269	22,218	22,166	22,114	268,482

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2009 - DECEMBER 2009

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

Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	0.009194		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)			2,458	2,453	2,447	2,441	2,436	2,430	2,424	2,418	2,412	2,406	2,402	2,396	29,123
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,458	2,453	2,447	2,441	2,436	2,430	2,424	2,418	2,412	2,406	2,402	2,396	29,123

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

Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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		$712,740	712,740	712,740	712,740	712,740	712,740	712,740	712,740	712,740	712,740	712,740	712,740	712,740	
3	Less: Accumulated Depreciation		($25,980)	(27,560)	(29,140)	(30,720)	(32,300)	(33,880)	(35,460)	(37,040)	(38,620)	(40,200)	(41,780)	(43,360)	(44,940)	
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)		$686,761	685,181	683,601	682,021	680,441	678,861	677,281	675,701	674,121	672,541	670,961	669,381	667,801	
6	Average Net Investment			685,971	684,391	682,811	681,231	679,651	678,071	676,491	674,911	673,331	671,751	670,171	668,591	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		6,380	6,365	6,350	6,335	6,321	6,306	6,291	6,277	6,262	6,247	6,233	6,218	$75,585
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,166	1,163	1,161	1,158	1,155	1,153	1,150	1,147	1,145	1,142	1,139	1,137	13,816
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.66%		1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	18,960
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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		494	494	494	494	494	494	494	494	494	494	494	494	5,928
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,620	9,602	9,585	9,567	9,550	9,533	9,515	9,498	9,481	9,463	9,446	9,429	114,289
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			9,620	9,602	9,585	9,567	9,550	9,533	9,515	9,498	9,481	9,463	9,446	9,429	114,289

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2009 - DECEMBER 2009

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

Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	0.008454		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)			14,328	14,298	14,267	14,237	14,206	14,176	14,146	14,115	14,084	14,055	14,024	13,993	169,929
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			14,328	14,298	14,267	14,237	14,206	14,176	14,146	14,115	14,084	14,055	14,024	13,993	169,929

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

Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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		$2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	2,665,776	
3	Less: Accumulated Depreciation		($2,588)	(7,764)	(12,940)	(18,116)	(23,292)	(28,468)	(33,644)	(38,820)	(43,996)	(49,172)	(54,348)	(59,524)	(64,700)	
4	CWIP - Non-Interest Bearing		($0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$2,663,188	2,658,012	2,652,836	2,647,660	2,642,484	2,637,308	2,632,132	2,626,956	2,621,780	2,616,604	2,611,428	2,606,252	2,601,076	
6	Average Net Investment			2,660,600	2,655,424	2,650,248	2,645,072	2,639,896	2,634,720	2,629,544	2,624,368	2,619,192	2,614,016	2,608,840	2,603,664	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		24,744	24,695	24,647	24,599	24,551	24,503	24,455	24,407	24,358	24,310	24,262	24,214	$293,745
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		4,523	4,514	4,505	4,497	4,488	4,479	4,470	4,461	4,453	4,444	4,435	4,426	53,695
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.33%		5,176	5,176	5,176	5,176	5,176	5,176	5,176	5,176	5,176	5,176	5,176	5,176	62,112
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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		1,926	1,926	1,926	1,926	1,926	1,926	1,926	1,926	1,926	1,926	1,926	1,926	23,112
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			36,369	36,311	36,254	36,198	36,141	36,084	36,027	35,970	35,913	35,856	35,799	35,742	432,664
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			36,369	36,311	36,254	36,198	36,141	36,084	36,027	35,970	35,913	35,856	35,799	35,742	432,664

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2009 - DECEMBER 2009

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

Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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		$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	0.014338		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)			2,209	2,200	2,191	2,182	2,174	2,165	2,156	2,147	2,139	2,130	2,121	2,113	25,927
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,209	2,200	2,191	2,182	2,174	2,165	2,156	2,147	2,139	2,130	2,121	2,113	25,927

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

Intermediate

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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		$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		($20,243)	(21,051)	(21,859)	(22,667)	(23,476)	(24,283)	(25,091)	(25,899)	(26,707)	(27,515)	(28,323)	(29,131)	(29,939)	
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)		$270,055	269,247	268,439	267,631	266,823	266,015	265,207	264,399	263,591	262,783	261,975	261,167	260,359	
6	Average Net Investment			269,651	268,843	268,035	267,227	266,419	265,611	264,803	263,995	263,187	262,379	261,571	260,763	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,508	2,500	2,493	2,485	2,478	2,470	2,463	2,455	2,448	2,440	2,433	2,425	$29,598
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		458	457	456	454	453	452	450	449	447	446	445	443	5,410
	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	0.007299		177	177	177	177	177	177	177	177	177	177	177	177	2,124
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,951	3,942	3,934	3,924	3,916	3,907	3,898	3,889	3,880	3,871	3,863	3,853	46,828
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,951	3,942	3,934	3,924	3,916	3,907	3,898	3,889	3,880	3,871	3,863	3,853	46,828

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2009 - DECEMBER 2009

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

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$25,000	$100,000	$75,000	$0	$0	$0	**$200,000**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	200,000	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	200,000	200,000	200,000	200,000	
3	Less: Accumulated Depreciation	$0	0	0	0	0	0	0	0	0	(464)	(1,392)	(2,320)	(3,248)	
4	CWIP - Non-Interest Bearing	$0	0	0	0	0	0	0	25,000	125,000	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	25,000	125,000	199,536	198,608	197,680	196,752	
6	Average Net Investment		0	0	0	0	0	0	12,500	75,000	162,268	199,072	198,144	197,216	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		0	0	0	0	0	0	116	698	1,509	1,851	1,843	1,834	$7,851
	b. Debt Component (Line 6 x **2.57%** x 1/12) **2.04%**		0	0	0	0	0	0	21	128	276	338	337	335	1,435
	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	0	0	0	464	928	928	928	3,248
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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**		0	0	0	0	0	0	0	0	139	139	139	139	556
	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	137	826	2,388	3,256	3,247	3,236	13,090
	a. 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	137	826	2,388	3,256	3,247	3,236	13,090

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2009 - DECEMBER 2009

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

ALL Peaking

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	0.009194		124	124	124	124	124	124	124	124	124	124	124	124	1,488
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,054	2,051	2,050	2,048	2,046	2,044	2,042	2,040	2,038	2,036	2,034	2,032	24,515
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,054	2,051	2,050	2,048	2,046	2,044	2,042	2,040	2,038	2,036	2,034	2,032	24,515

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

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	0.008313		191	191	191	191	191	191	191	191	191	191	191	191	2,292
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,863	3,855	3,847	3,837	3,829	3,821	3,812	3,804	3,796	3,788	3,779	3,771	45,802
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,863	3,855	3,847	3,837	3,829	3,821	3,812	3,804	3,796	3,788	3,779	3,771	45,802

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2009 - DECEMBER 2009

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

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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		$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		($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	0.008313		138	138	138	138	138	138	138	138	138	138	138	138	1,656
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,696	2,691	2,686	2,682	2,677	2,672	2,668	2,663	2,658	2,653	2,649	2,644	32,039
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,696	2,691	2,686	2,682	2,677	2,672	2,668	2,663	2,658	2,653	2,649	2,644	32,039

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

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	84,021	83,773	83,525	83,277	83,029	82,781	82,533	82,285	82,037	81,789	81,541	81,293	
6	Average Net Investment			84,145	83,897	83,649	83,401	83,153	82,905	82,657	82,409	82,161	81,913	81,665	81,417	
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	0.008670		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)			1,237	1,234	1,231	1,229	1,225	1,223	1,221	1,217	1,215	1,212	1,209	1,206	14,659
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,237	1,234	1,231	1,229	1,225	1,223	1,221	1,217	1,215	1,212	1,209	1,206	14,659

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2009 - DECEMBER 2009

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

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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		$373,316	373,316	373,316	373,316	373,316	373,316	373,316	373,316	373,316	373,316	373,316	373,316	373,316	
3	Less: Accumulated Depreciation		($3,379)	(3,690)	(4,001)	(4,312)	(4,623)	(4,934)	(5,245)	(5,556)	(5,867)	(6,178)	(6,489)	(6,800)	(7,111)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$369,937	369,626	369,315	369,004	368,693	368,382	368,071	367,760	367,449	367,138	366,827	366,516	366,205	
6	Average Net Investment			369,781	369,470	369,159	368,848	368,537	368,226	367,915	367,604	367,293	366,982	366,671	366,360	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,439	3,436	3,433	3,430	3,427	3,425	3,422	3,419	3,416	3,413	3,410	3,407	$41,077
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		629	628	628	627	627	626	625	625	624	624	623	623	7,509
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.00%		311	311	311	311	311	311	311	311	311	311	311	311	3,732
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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		259	259	259	259	259	259	259	259	259	259	259	259	3,108
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,638	4,634	4,631	4,627	4,624	4,621	4,617	4,614	4,610	4,607	4,603	4,600	55,426
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,638	4,634	4,631	4,627	4,624	4,621	4,617	4,614	4,610	4,607	4,603	4,600	55,426

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

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	0.007614		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)			4,716	4,708	4,700	4,691	4,683	4,674	4,665	4,657	4,649	4,640	4,632	4,624	56,039
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,716	4,708	4,700	4,691	4,683	4,674	4,665	4,657	4,649	4,640	4,632	4,624	56,039

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2009 - DECEMBER 2009

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

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	0.008974		100	100	100	100	100	100	100	100	100	100	100	100	1,200
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,834	1,830	1,827	1,823	1,820	1,817	1,813	1,810	1,806	1,803	1,799	1,797	21,779
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,834	1,830	1,827	1,823	1,820	1,817	1,813	1,810	1,806	1,803	1,799	1,797	21,779

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

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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		$382,160	382,160	382,160	382,160	382,160	382,160	382,160	382,160	382,160	382,160	382,160	382,160	382,160	
3	Less: Accumulated Depreciation		($7,738)	(8,413)	(9,088)	(9,763)	(10,438)	(11,113)	(11,788)	(12,463)	(13,138)	(13,813)	(14,488)	(15,163)	(15,838)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$374,422	373,747	373,072	372,397	371,722	371,047	370,372	369,697	369,022	368,347	367,672	366,997	366,322	
6	Average Net Investment			374,084	373,409	372,734	372,059	371,384	370,709	370,034	369,359	368,684	368,009	367,334	366,659	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,479	3,473	3,466	3,460	3,454	3,448	3,441	3,435	3,429	3,422	3,416	3,410	$41,333
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		636	635	634	633	631	630	629	628	627	626	624	623	7,556
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.12%		675	675	675	675	675	675	675	675	675	675	675	675	8,100
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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		269	269	269	269	269	269	269	269	269	269	269	269	3,228
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,059	5,052	5,044	5,037	5,029	5,022	5,014	5,007	5,000	4,992	4,984	4,977	60,217
	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			5,059	5,052	5,044	5,037	5,029	5,022	5,014	5,007	5,000	4,992	4,984	4,977	60,217

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2009 - DECEMBER 2009

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	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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		$15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	15,748,246	
3	Less: Accumulated Depreciation		($331,422)	(375,911)	(420,400)	(464,889)	(509,378)	(553,867)	(598,356)	(642,845)	(687,334)	(731,823)	(776,312)	(820,801)	(865,290)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$15,416,824	15,372,335	15,327,846	15,283,357	15,238,868	15,194,379	15,149,890	15,105,401	15,060,912	15,016,423	14,971,934	14,927,445	14,882,956	
6	Average Net Investment			15,394,580	15,350,091	15,305,602	15,261,113	15,216,624	15,172,135	15,127,646	15,083,157	15,038,668	14,994,179	14,949,690	14,905,201	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		143,170	142,756	142,342	141,928	141,515	141,101	140,687	140,273	139,860	139,446	139,032	138,618	$1,690,728
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		26,171	26,095	26,020	25,944	25,868	25,793	25,717	25,641	25,566	25,490	25,414	25,339	309,058
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.39%		44,489	44,489	44,489	44,489	44,489	44,489	44,489	44,489	44,489	44,489	44,489	44,489	533,868
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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		14,051	14,051	14,051	14,051	14,051	14,051	14,051	14,051	14,051	14,051	14,051	14,051	168,612
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			227,881	227,391	226,902	226,412	225,923	225,434	224,944	224,454	223,966	223,476	222,986	222,497	2,702,266
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			227,881	227,391	226,902	226,412	225,923	225,434	224,944	224,454	223,966	223,476	222,986	222,497	2,702,266

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2009 - DECEMBER 2009
For Project: CAIR/CAMR Crystal River AFUDC - Low Nox Burner CR4 (Project 7.4b)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$2,234	$2,234	$2,234	$2,234	$2,234	$2,234	$2,234	$2,234	$2,234	$102,234	$52,234	$27,658	**$202,234**
	b. Clearings to Plant			2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234	102,234	52,234	27,658	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		**$5,279,189**	5,281,423	5,283,657	5,285,892	5,288,126	5,290,360	5,292,594	5,294,828	5,297,063	5,299,297	5,401,531	5,453,765	5,481,423	
3	Less: Accumulated Depreciation		**($6,225)**	(18,660)	(31,141)	(43,607)	(56,078)	(68,554)	(81,036)	(93,523)	(106,015)	(118,513)	(131,252)	(144,114)	(157,041)	
4	CWIP - Non-Interest Bearing		**$0**	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		**$5,272,964**	5,262,743	5,252,516	5,242,285	5,232,048	5,221,806	5,211,558	5,201,305	5,191,048	5,180,784	5,270,279	5,309,651	5,324,382	
6	Average Net Investment			5,267,854	5,257,630	5,247,401	5,237,166	5,226,927	5,216,682	5,206,432	5,196,177	5,185,916	5,225,531	5,289,965	5,317,017	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		48,991	48,896	48,801	48,706	48,610	48,515	48,420	48,324	48,229	48,597	49,197	49,448	$584,734
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		8,955	8,938	8,921	8,903	8,886	8,868	8,851	8,834	8,816	8,883	8,993	9,039	106,887
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		12,455	12,461	12,466	12,471	12,476	12,482	12,487	12,492	12,498	12,739	12,862	12,927	150,816
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/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		4,712	4,714	4,716	4,718	4,720	4,722	4,724	4,726	4,728	4,819	4,866	4,891	57,056
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			75,113	75,009	74,904	74,798	74,692	74,587	74,482	74,376	74,271	75,038	75,918	76,305	899,493
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			75,113	75,009	74,904	74,798	74,692	74,587	74,482	74,376	74,271	75,038	75,918	76,305	899,493

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2009 - DECEMBER 2009
For Project: CAIR/CAMR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Base

Line	Description	Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$2,011,694	$1,723,247	$897,424	$1,564,137	$1,442,590	$1,846,193	$215,106	**$9,700,388**
	b. Clearings to Plant		0	0	0	0	109,054,962	2,011,694	1,723,247	897,424	1,564,137	1,442,590	1,846,193	215,106	
	c. Retirements		0	0	0	0	0	0	0	0	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	109,054,962	111,066,656	112,789,903	113,687,326	115,251,463	116,694,052	118,540,245	118,755,351	
3	Less: Accumulated Depreciation	**$0**	0	0	0	0	(128,594)	(390,526)	(656,522)	(924,635)	(1,196,436)	(1,471,639)	(1,751,196)	(2,031,261)	
4	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	108,926,368	110,676,130	112,133,380	112,762,691	114,055,027	115,222,413	116,789,049	116,724,090	
6	Average Net Investment		0	0	0	0	54,463,184	109,801,249	111,404,755	112,448,036	113,408,859	114,638,720	116,005,731	116,756,569	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes	11.16%	0	0	0	0	506,508	1,021,152	1,036,064	1,045,767	1,054,702	1,066,140	1,078,853	1,085,836	$7,895,022
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%	0	0	0	0	92,587	186,662	189,388	191,162	192,795	194,886	197,210	198,486	1,443,176
	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	128,594	261,932	265,996	268,113	271,801	275,203	279,557	280,065	2,031,261
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/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	97,302	99,097	100,634	101,435	102,831	104,118	105,765	105,957	817,139
	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	824,991	1,568,843	1,592,082	1,606,477	1,622,129	1,640,347	1,661,385	1,670,344	12,186,598
	a. 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	824,991	1,568,843	1,592,082	1,606,477	1,622,129	1,640,347	1,661,385	1,670,344	12,186,598

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2009 - DECEMBER 2009
For Project: CAIR/CAMR Crystal River AFUDC - Urea to Ammonia System (Project 7.4d)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected 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	24,228,085	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	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	24,228,085	24,228,085	24,228,085	24,228,085	24,228,085	24,228,085	24,228,085	24,228,085	
3	Less: Accumulated Depreciation		$0	0	0	0	0	(28,569)	(85,707)	(142,845)	(199,983)	(257,121)	(314,259)	(371,397)	(428,535)	
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)		$0	0	0	0	0	24,199,516	24,142,378	24,085,240	24,028,102	23,970,964	23,913,826	23,856,688	23,799,550	
6	Average Net Investment			0	0	0	0	12,099,758	24,170,947	24,113,809	24,056,671	23,999,533	23,942,395	23,885,257	23,828,119	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	112,528	224,790	224,258	223,727	223,196	222,664	222,133	221,602	$1,674,898
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	20,570	41,091	40,993	40,896	40,799	40,702	40,605	40,508	306,164
	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	28,569	57,138	57,138	57,138	57,138	57,138	57,138	57,138	428,535
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/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	21,617	21,617	21,617	21,617	21,617	21,617	21,617	21,617	172,936
	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	183,284	344,636	344,006	343,378	342,750	342,121	341,493	340,865	2,582,533
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	183,284	344,636	344,006	343,378	342,750	342,121	341,493	340,865	2,582,533

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2009 - DECEMBER 2009
For Project: CAIR/CAMR Crystal River AFUDC - Common Items (Project 7.4e)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,908,117	**$10,908,117**
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	599,001,816	10,908,117	
	c. Retirements			0	0	0	0	0	0	0	0	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	599,001,816.29	609,909,933	
3	Less: Accumulated Depreciation		$0	0	0	0	0	0	0	0	0	0	0	(706,323)	(2,131,831)	
4	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	598,295,493	607,778,102	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	299,147,747	603,036,798	
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	2,782,074	5,608,242	$8,390,316
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	508,551	1,025,163	1,533,714
	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	706,323	1,425,508	2,131,831
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/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	534,447	544,180	1,078,627
	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	4,531,395	8,603,093	13,134,488
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	4,531,395	8,603,093	13,134,488

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2009 - DECEMBER 2009
For Project: CAIR/CAMR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Projected Jan-09	Projected Feb-09	Projected Mar-09	Projected Apr-09	Projected May-09	Projected Jun-09	Projected Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Projected Nov-09	Projected Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$232,652	**$232,652**
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	160,478,466	232,652	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	160,478,466	160,711,118	
3	Less: Accumulated Depreciation		$0	0	0	0	0	0	0	0	0	0	0	(189,231)	(568,241)	
4	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	160,289,235	160,142,877	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	80,144,618	160,216,056	
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	745,345	1,490,009	$2,235,354
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	136,246	272,367	408,613
	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	189,231	379,010	568,241
	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	0.010707		0	0	0	0	0	0	0	0	0	0	143,184	143,391	286,575
	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	1,214,006	2,284,777	3,498,783
	a. 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	1,214,006	2,284,777	3,498,783

DOCKET NO. 080007-EI
FINAL ECRC 2007 TRUE-UP
EXHIBIT HTB-1

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2007 THROUGH DECEMBER 2007

FORMS 42-1A THROUGH 42-8A

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 20
COMPANY TECO (Direct)
WITNESS Howard T. Bryant (HTB-1)
DATE 11-04-08

DOCKET NO. 080007-EI
FINAL ECRC 2007 TRUE-UP
EXHIBIT HTB-1

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TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2007 THROUGH DECEMBER 2007

FORMS 42-1A THROUGH 42-8A

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Tampa Electric Company Form 42 - 1A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007
(in Dollars)

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2007 to December 2007 (Form 42-2A, Lines 5 + 6 + 10)	$22,089,826
2	Estimated/Actual True-Up Amount Approved for the Period January 2007 to December 2007 (Order No. PSC-07-0922 FOF-EI)	9,624,173
4.	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2009 to December 2009 (Lines 1 - 2)	$12,465,653

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Form 42 - 2A

Current Period True-Up Amount
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	ECRC Revenues (net of Revenue Taxes)	($5,265,935)	($4,789,886)	($4,781,167)	($4,928,971)	($5,337,681)	($5,850,945)	($6,496,394)	($6,565,988)	($7,081,686)	($6,089,819)	($5,198,503)	($4,937,115)	($67,324,090)
2.	True-Up Provision	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,852	34,738,235
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	(2,371,082)	(1,895,033)	(1,886,314)	(2,034,118)	(2,442,828)	(2,956,092)	(3,601,541)	(3,671,135)	(4,186,833)	(3,194,966)	(2,303,650)	(2,042,263)	(32,585,856)
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	823,958	1,399,886	1,248,559	(188,756)	(11,254,749)	(3,092,906)	(5,563,023)	(20,943,114)	(8,269,493)	(11,010,637)	(5,903,794)	(13,601,439)	(76,355,508)
	b. Capital Investment Projects (Form 42-7A, Line 9)	1,385,233	1,371,847	1,400,704	1,390,507	1,566,905	2,097,636	2,094,801	2,087,565	2,106,984	2,075,179	2,111,380	2,125,816	21,814,557
	c. Total Jurisdictional ECRC Costs	2,209,191	2,771,733	2,649,263	1,201,751	(9,687,844)	(995,270)	(3,468,222)	(18,855,549)	(6,162,509)	(8,935,458)	(3,792,414)	(11,475,623)	(54,540,951)
5.	Over/Under Recovery (Line 3 - Line 4c)	(4,580,273)	(4,666,766)	(4,535,577)	(3,235,869)	7,245,016	(1,960,822)	(133,319)	15,184,414	1,975,676	5,740,492	1,488,764	9,433,360	21,955,096
6.	Interest Provision (Form 42-3A, Line 10)	83,871	51,117	18,508	(11,110)	(15,058)	(16,268)	(33,568)	(13,892)	11,590	14,568	17,039	27,933	134,730
7.	Beginning Balance True-Up & Interest Provision	34,738,235	27,346,980	19,836,478	12,424,556	6,282,724	10,617,829	5,745,886	2,684,146	14,959,815	14,052,228	16,912,435	15,523,385	34,738,235
	a. Deferred True-Up from January to December 2006 (Order No. PSC-07-0922-FOF-EI)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)
8.	True-Up Collected/(Refunded) (see Line 2)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,852)	(34,738,235)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	15,451,297	7,940,795	528,873	(5,612,959)	(1,277,854)	(6,149,797)	(9,211,537)	3,064,132	2,156,545	5,016,752	3,627,702	10,194,143	10,194,143
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)	$15,451,297	$7,940,795	$528,873	($5,612,959)	($1,277,854)	($6,149,797)	($9,211,537)	$3,064,132	$2,156,545	$5,016,752	$3,627,702	$10,194,143	$10,194,143

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Form 42 - 3A

Interest Provision
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$22,842,552	$15,451,297	$7,940,795	$528,873	($5,612,959)	($1,277,854)	($6,149,797)	($9,211,537)	$3,064,132	$2,156,545	$5,016,752	$3,627,702	
2.	Ending True-Up Amount Before Interest	15,367,426	7,889,678	510,365	(5,601,849)	(1,262,796)	(6,133,529)	(9,177,969)	3,078,024	2,144,955	5,002,184	3,610,663	10,166,210	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	38,209,978	23,340,975	8,451,160	(5,072,976)	(6,875,755)	(7,411,383)	(15,327,766)	(6,133,513)	5,209,087	7,158,729	8,627,415	13,793,912	
4.	Average True-Up Amount (Line 3 x 1/2)	19,104,989	11,670,488	4,225,580	(2,536,488)	(3,437,878)	(3,705,692)	(7,663,883)	(3,066,757)	2,604,544	3,579,365	4,313,708	6,896,956	
5.	Interest Rate (First Day of Reporting Business Month)	5.27%	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.24%	5.62%	5.05%	4.72%	4.75%	
6.	Interest Rate (First Day of Subsequent Business Month)	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.24%	5.62%	5.05%	4.72%	4.75%	4.98%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53%	10.52%	10.52%	10.52%	10.52%	10.54%	10.52%	10.86%	10.67%	9.77%	9.47%	9.73%	
8.	Average Interest Rate (Line 7 x 1/2)	5.265%	5.260%	5.260%	5.260%	5.260%	5.270%	5.260%	5.430%	5.335%	4.885%	4.735%	4.865%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.439%	0.438%	0.438%	0.438%	0.438%	0.439%	0.438%	0.453%	0.445%	0.407%	0.395%	0.405%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$83,871	$51,117	$18,508	($11,110)	($15,058)	($16,268)	($33,568)	($13,892)	$11,590	$14,568	$17,039	$27,933	$134,730

Tampa Electric Company Form 42 - 4A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

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	$4,446,440	4,514,051	($67,611)	-1.5%
b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
c. SO_2 Emissions Allowances	(90,963,247)	(79,602,597)	(11,360,650)	-14.3%
d. Big Bend Units 1 & 2 FGD	4,951,987	$5,477,691	(525,704)	-9.6%
e. Big Bend PM Minimization and Monitoring	343,977	$310,000	33,977	11.0%
f. Big Bend NO_x Emissions Reduction	440,160	$490,000	(49,840)	-10.2%
g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
h. Gannon Thermal Discharge Study	44,650	26,117	18,533	71.0%
i. Polk NO_x Emissions Reduction	72,418	$59,725	12,693	21.3%
j. Bayside SCR Consumables	74,550	$69,604	4,946	7.1%
k. Big Bend Unit 4 SOFA	262,586	220,000	42,586	19.4%
l. Big Bend Unit 1 Pre-SCR	4,586	0	4,586	NA
m. Big Bend Unit 2 Pre-SCR	6,635	15,000	(8,365)	-55.8%
n. Big Bend Unit 3 Pre-SCR	23,995	0	23,995	NA
o. Clean Water Act Section 316(b) Phase II Study	341,414	396,758	(55,344)	-13.9%
p. Arsenic Groundwater Standard Program	10,230	52,500	(42,270)	-80.5%
q. Big Bend 4 SCR	594,368	759,873	(165,505)	-21.8%
2. Total Investment Projects - Recoverable Costs	($79,310,751)	($67,176,778)	($12,133,973)	-18.1%
3. Recoverable Costs Allocated to Energy	($79,741,545)	($67,686,653)	($12,054,892)	-17.8%
4. Recoverable Costs Allocated to Demand	$430,794	$509,875	($79,081)	-15.5%

Notes:

Column (1) is the End of Period Totals on Form 42-5E.
Column (2) is the approved projected amount in accordance with Commission Order No. PSC-07-0922-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Form 42 - 5A

O&M Activities
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	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	$299,597	$812,230	$367,415	$440,618	$271,213	$376,445	$386,471	$365,484	$273,624	$329,863	$229,196	$294,284	$4,446,440		$4,446,440
	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	(25,909)	13,178	15,874	(1,028,135)	(12,471,000)	(4,077,470)	(6,696,385)	(22,941,710)	(9,369,596)	(12,403,958)	(6,981,217)	(14,996,919)	(90,963,247)		(90,963,247)
	d. Big Bend Units 1 & 2 FGD	615,331	290,459	312,229	459,151	372,698	358,403	412,162	445,740	395,247	493,366	376,953	420,248	4,951,987		4,951,987
	e. Big Bend PM Minimization and Monitoring	12,234	48,962	46,732	17,941	33,164	26,893	23,480	23,562	31,944	15,131	24,804	39,130	343,977		343,977
	f. Big Bend NO_x Emissions Reduction	15,319	128,663	324,729	(128,422)	14,248	11,196	7,158	37,686	(117)	5,146	6,693	17,861	440,160		440,160
	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	4,902	6,031	4,850	1,725	977	7,632	6,332	0	1,108	1,425	1,254	8,414	44,650	44,650	
	i. Polk NO_x Emissions Reduction	2,588	2,142	6,840	3,394	12,833	10,325	5,711	3,340	8,608	3,223	7,950	5,464	72,418		72,418
	j. Bayside SCR Consumables	8,158	0	8,069	0	8,877	0	17,737	8,413	(406)	17,143	6,559	0	74,550		74,550
	k. Big Bend Unit 4 SOFA	0	9,844	159,897	(9,689)	2,977	0	0	0	11,189	25,108	63,260	0	262,586		262,586
	l. Big Bend Unit 1 Pre-SCR	543	0	0	0	0	(543)	0	0	0	4,586	0	0	4,586		4,586
	m. Big Bend Unit 2 Pre-SCR	1,100	0	2,710	0	5,713	(14,188)	33	0	10,267	0	0	1,000	6,635		6,635
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	4,947	19,048	23,995		23,995
	o. Clean Water Act Section 316(b) Phase II Study	(124,116)	146,545	38,124	45,528	34,912	19,489	0	11,320	38,666	0	69,667	61,279	341,414	341,414	
	p. Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	10,230	0	0	0	0	10,230	10,230	
	q. Big Bend 4 SCR	0	0	0	0	7,596	80,867	60,481	198,086	62,847	(12,674)	101,433	95,732	594,368		594,368
2.	Total of O&M Activities	844,247	1,458,054	1,287,469	(197,889)	(11,705,792)	(3,200,951)	(5,776,820)	(21,837,849)	(8,536,619)	(11,521,641)	(6,088,501)	(14,034,459)	(79,310,751)	$430,794	($79,741,545)
3.	Recoverable Costs Allocated to Energy	928,961	1,305,478	1,244,495	(245,142)	(11,741,681)	(3,228,072)	(5,783,152)	(21,859,399)	(8,576,393)	(11,523,066)	(6,159,422)	(14,104,152)	(79,741,545)		
4.	Recoverable Costs Allocated to Demand	(84,714)	152,576	42,974	47,253	35,889	27,121	6,332	21,550	39,774	1,425	70,921	69,693	430,794		
5.	Retail Energy Jurisdictional Factor	0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337			
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 (A)	905,849	1,252,395	1,207,017	(234,434)	(11,289,442)	(3,119,123)	(5,569,144)	(20,963,946)	(8,307,942)	(11,012,015)	(5,972,352)	(13,668,809)	(76,771,946)		
8.	Jurisdictional Demand Recoverable Costs (B)	(81,891)	147,491	41,542	45,678	34,693	26,217	6,121	20,832	38,449	1,378	68,558	67,370	416,438		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$823,958	$1,399,886	$1,248,559	($188,756)	($11,254,749)	($3,092,906)	($5,563,023)	($20,943,114)	($8,269,493)	($11,010,637)	($5,903,794)	($13,601,439)	($76,355,508)		

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

DOCKET NO. 080007-EI
ECRC 2007 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 5, PAGE 1 OF 1

Tampa Electric Company Form 42 - 6A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

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	$830,177	$830,177	$0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	478,165	478,165	0	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	84,822	84,822	0	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	57,574	57,574	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	94,694	94,694	0	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	6,262	6,262	0	0.0%
	g. Phillips Upgrade Tank # 4 for FDEP	9,842	9,842	0	0.0%
	h. Big Bend Unit 1 Classifier Replacement	148,910	148,910	0	0.0%
	i. Big Bend Unit 2 Classifier Replacement	107,596	107,596	0	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	14,137	14,137	0	0.0%
	k. Big Bend Units 1 & 2 FGD	9,156,670	9,156,955	(285)	0.0%
	l. Big Bend FGD Optimization and Utilization	2,648,825	2,648,825	0	0.0%
	m. Big Bend NO_x Emissions Reduction	843,258	866,806	(23,548)	-2.7%
	n. Big Bend PM Minimization and Monitoring	1,102,382	1,102,382	0	0.0%
	o. Polk NO_x Emissions Reduction	214,062	214,062	0	0.0%
	p. Big Bend Unit 4 SOFA	339,250	339,250	0	0.0%
	q. Big Bend Unit 1 Pre-SCR	283,729	283,636	93	0.0%
	r. Big Bend Unit 2 Pre-SCR	228,630	228,630	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	125,209	133,737	(8,528)	-6.4%
	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	0	0	0	0.0%
	w. Big Bend Unit 4 SCR	5,131,544	5,145,048	(13,504)	-0.3%
	x. Big Bend FGD System Reliability	769,057	778,808	(9,751)	-1.3%
	y. Clean Air Mercury Rule	7,913	0	7,913	NA
	z. SO_2 Emissions Allowances	(64,117)	(66,968)	2,851	4.3%
2.	Total Investment Projects - Recoverable Costs	$22,618,591	$22,663,350	($44,759)	-0.2%
3.	Recoverable Costs Allocated to Energy	$22,450,219	$22,494,978	($44,759)	-0.2%
4.	Recoverable Costs Allocated to Demand	$168,372	$168,372	$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 Order No. PSC-07-0922-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Form 42-7A

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$70,024	$69,871	$69,718	$69,565	$69,411	$69,258	$69,105	$68,951	$68,798	$68,645	$68,492	$68,339	$830,177		$830,177
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	40,562	40,433	40,302	40,173	40,042	39,912	39,782	39,652	39,522	39,392	39,261	39,132	478,165		478,165
	c.	Big Bend Unit 4 Continuous Emissions Monitors	7,149	7,135	7,120	7,106	7,090	7,076	7,061	7,046	7,032	7,017	7,003	6,987	84,822		84,822
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,855	4,845	4,835	4,824	4,814	4,803	4,793	4,782	4,772	4,761	4,750	4,740	57,574	$ 57,574	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,986	7,968	7,951	7,934	7,917	7,900	7,883	7,865	7,848	7,831	7,814	7,797	94,694	94,694	
	f.	Phillips Upgrade Tank # 1 for FDEP	530	528	527	526	524	523	521	519	518	517	515	514	6,262	6,262	
	g.	Phillips Upgrade Tank # 4 for FDEP	832	830	828	825	824	821	819	817	815	812	811	808	9,842	9,842	
	h.	Big Bend Unit 1 Classifier Replacement	12,602	12,567	12,532	12,497	12,462	12,427	12,391	12,357	12,321	12,287	12,251	12,216	148,910		148,910
	i.	Big Bend Unit 2 Classifier Replacement	9,102	9,077	9,052	9,028	9,003	8,978	8,954	8,929	8,905	8,881	8,856	8,831	107,596		107,596
	j.	Big Bend Section 114 Mercury Testing Platform	1,189	1,187	1,185	1,183	1,181	1,179	1,177	1,175	1,173	1,171	1,170	1,167	14,137		14,137
	k.	Big Bend Units 1 & 2 FGD	773,612	771,887	769,929	767,971	766,012	764,054	762,096	760,138	758,179	756,222	754,264	752,306	9,156,670		9,156,670
	l.	Big Bend FGD Optimization and Utilization	222,958	222,554	222,150	221,745	221,341	220,937	220,534	220,130	219,725	219,321	218,917	218,513	2,648,825		2,648,825
	m.	Big Bend NO_x Emissions Reduction	73,064	72,909	72,754	72,600	72,445	72,291	72,136	69,327	66,554	66,474	66,393	66,311	843,258		843,258
	n.	Big Bend PM Minimization and Monitoring	92,943	92,747	92,551	92,355	92,159	91,963	91,767	91,571	91,375	91,180	90,983	90,788	1,102,382		1,102,382
	o.	Polk NO_x Emissions Reduction	18,075	18,032	17,989	17,946	17,902	17,860	17,817	17,774	17,731	17,688	17,645	17,603	214,062		214,062
	p.	Big Bend Unit 4 SOFA	28,544	28,494	28,445	28,395	28,346	28,296	28,246	28,197	28,147	28,096	28,047	27,997	339,250		339,250
	q.	Big Bend Unit 1 Pre-SCR	21,814	24,031	23,966	23,928	23,887	23,846	23,806	23,765	23,726	23,686	23,654	23,620	283,729		283,729
	r.	Big Bend Unit 2 Pre-SCR	17,447	19,397	19,357	19,318	19,278	19,238	19,199	19,159	19,119	19,079	19,039	19,000	228,630		228,630
	s.	Big Bend Unit 3 Pre-SCR	7,225	7,552	7,865	8,214	8,249	8,246	9,484	10,732	10,757	10,809	15,576	20,500	125,209		125,209
	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	0	0	0	0	0	0	0		0
	w.	Big Bend Unit 4 SCR	0	0	0	0	169,240	704,920	709,200	711,363	712,140	709,259	707,615	707,807	5,131,544		5,131,544
	x.	Big Bend FGD System Reliability	18,024	25,414	42,726	55,199	64,410	72,680	74,416	76,434	77,949	79,256	84,667	97,882	769,057		769,057
	y.	Clean Air Mercury Rule	0	0	0	0	0	0	0	811	1,651	1,725	1,824	1,902	7,913		7,913
	z.	SO_2 Emissions Allowances (B)	(7,837)	(7,573)	(7,539)	(7,466)	(6,940)	(6,309)	(5,942)	(4,872)	(3,662)	(2,784)	(1,990)	(1,203)	(64,117)		(64,117)
2.		Total Investment Projects - Recoverable Costs	1,420,700	1,429,885	1,444,243	1,453,866	1,629,597	2,170,899	2,175,245	2,176,622	2,175,095	2,171,325	2,177,557	2,193,557	22,618,591	$ 168,372	$ 22,450,219
3.		Recoverable Costs Allocated to Energy	1,406,497	1,415,714	1,430,102	1,439,757	1,615,518	2,156,852	2,161,229	2,162,639	2,161,142	2,157,404	2,163,667	2,179,698	22,450,219		
4.		Recoverable Costs Allocated to Demand	14,203	14,171	14,141	14,109	14,079	14,047	14,016	13,983	13,953	13,921	13,890	13,859	168,372		
5.		Retail Energy Jurisdictional Factor	0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337			
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)*	1,371,503	1,358,148	1,387,034	1,376,868	1,553,295	2,084,057	2,081,252	2,074,048	2,093,496	2,061,722	2,097,953	2,112,419	21,651,795		
8.		Jurisdictional Demand Recoverable Costs (D)	13,730	13,699	13,670	13,639	13,610	13,579	13,549	13,517	13,488	13,457	13,427	13,397	162,762		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,385,233	$1,371,847	$1,400,704	$1,390,507	$1,566,905	$2,097,636	$2,094,801	$2,087,565	$2,106,984	$2,075,179	$2,111,380	$2,125,816	$21,814,557		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Project's Total Return Component on Form 42-8A, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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ECRC 2007 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 2007 to December 2007

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	January	February	March	April	May	June	July	August	September	October	November	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	(2,642,745)	(2,658,538)	(2,674,331)	(2,690,124)	(2,705,917)	(2,721,710)	(2,737,503)	(2,753,296)	(2,769,089)	(2,784,882)	(2,800,675)	(2,816,468)	(2,832,261)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 5,596,913	5,581,120	5,565,327	5,549,534	5,533,741	5,517,948	5,502,155	5,486,362	5,470,569	5,454,776	5,438,983	5,423,190	5,407,397	
6.	Average Net Investment		5,589,017	5,573,224	5,557,431	5,541,638	5,525,845	5,510,052	5,494,259	5,478,466	5,462,673	5,446,880	5,431,087	5,415,294	
7.	*Return on Average Net Investment*														
	a. Equity Component Grossed Up For Taxes (B)		41,097	40,981	40,865	40,749	40,632	40,516	40,400	40,284	40,168	40,052	39,936	39,820	$ 485,500
	b. Debt Component (Line 6 x 2.82% x 1/12)		13,134	13,097	13,060	13,023	12,986	12,949	12,912	12,874	12,837	12,800	12,763	12,726	155,161
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)		70,024	69,871	69,718	69,565	69,411	69,258	69,105	68,951	68,798	68,645	68,492	68,339	830,177
	a. Recoverable Costs Allocated to Energy		70,024	69,871	69,718	69,565	69,411	69,258	69,105	68,951	68,798	68,645	68,492	68,339	830,177
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		68,282	67,030	67,618	66,526	66,738	66,921	66,548	66,126	66,645	65,601	66,412	66,230	800,677
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)		$ 68,282	$ 67,030	$ 67,618	$ 66,526	$ 66,738	$ 66,921	$ 66,548	$ 66,126	$ 66,645	$ 65,601	$ 66,412	$ 66,230	$ 800,677

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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

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	January	February	March	April	May	June	July	August	September	October	November	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	(2,212,586)	(2,225,995)	(2,239,404)	(2,252,813)	(2,266,222)	(2,279,631)	(2,293,040)	(2,306,449)	(2,319,858)	(2,333,267)	(2,346,676)	(2,360,085)	(2,373,494)	
4.	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)	$ 2,805,148	2,791,739	2,778,330	2,764,921	2,751,512	2,738,103	2,724,694	2,711,285	2,697,876	2,684,467	2,671,058	2,657,649	2,644,240	
6.	Average Net Investment		2,798,444	2,785,035	2,771,626	2,758,217	2,744,808	2,731,399	2,717,990	2,704,581	2,691,172	2,677,763	2,664,354	2,650,945	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		20,577	20,479	20,380	20,282	20,183	20,084	19,986	19,887	19,789	19,690	19,591	19,493	$ 240,421
	b. Debt Component (Line 6 x 2.82% x 1/12)		6,576	6,545	6,513	6,482	6,450	6,419	6,387	6,356	6,324	6,293	6,261	6,230	76,836
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)		40,562	40,433	40,302	40,173	40,042	39,912	39,782	39,652	39,522	39,392	39,261	39,132	478,165
	a. Recoverable Costs Allocated to Energy		40,562	40,433	40,302	40,173	40,042	39,912	39,782	39,652	39,522	39,392	39,261	39,132	478,165
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		39,553	38,789	39,088	38,418	38,500	38,565	38,310	38,028	38,285	37,645	38,069	37,924	461,174
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)		$ 39,553	$ 38,789	$ 39,088	$ 38,418	$ 38,500	$ 38,565	$ 38,310	$ 38,028	$ 38,285	$ 37,645	$ 38,069	$ 37,924	$ 461,174

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(284,885)	(286,401)	(287,917)	(289,433)	(290,949)	(292,465)	(293,981)	(295,497)	(297,013)	(298,529)	(300,045)	(301,561)	(303,077)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 581,326	579,810	578,294	576,778	575,262	573,746	572,230	570,714	569,198	567,682	566,166	564,650	563,134	
6.	Average Net Investment		580,568	579,052	577,536	576,020	574,504	572,988	571,472	569,956	568,440	566,924	565,408	563,892	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		4,269	4,258	4,247	4,236	4,224	4,213	4,202	4,191	4,180	4,169	4,158	4,146	$ 50,493
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,364	1,361	1,357	1,354	1,350	1,347	1,343	1,339	1,336	1,332	1,329	1,325	16,137
8.	Investment Expenses														
	a. Depreciation (D)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,149	7,135	7,120	7,106	7,090	7,076	7,061	7,046	7,032	7,017	7,003	6,987	84,822
	a. Recoverable Costs Allocated to Energy		7,149	7,135	7,120	7,106	7,090	7,076	7,061	7,046	7,032	7,017	7,003	6,987	84,822
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		6,971	6,845	6,906	6,796	6,817	6,837	6,800	6,757	6,812	6,706	6,790	6,771	81,808
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 6,971	$ 6,845	$ 6,906	$ 6,796	$ 6,817	$ 6,837	$ 6,800	$ 6,757	$ 6,812	$ 6,706	$ 6,790	$ 6,771	$ 81,808

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(107,752)	(108,830)	(109,908)	(110,986)	(112,064)	(113,142)	(114,220)	(115,298)	(116,376)	(117,454)	(118,532)	(119,610)	(120,688)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 389,826	388,748	387,670	386,592	385,514	384,436	383,358	382,280	381,202	380,124	379,046	377,968	376,890	
6.	Average Net Investment		389,287	388,209	387,131	386,053	384,975	383,897	382,819	381,741	380,663	379,585	378,507	377,429	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,862	2,855	2,847	2,839	2,831	2,823	2,815	2,807	2,799	2,791	2,783	2,775	$33,827
	b. Debt Component (Line 6 x 2.82% x 1/12)		915	912	910	907	905	902	900	897	895	892	889	887	10,811
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)		4,855	4,845	4,835	4,824	4,814	4,803	4,793	4,782	4,772	4,761	4,750	4,740	57,574
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,855	4,845	4,835	4,824	4,814	4,803	4,793	4,782	4,772	4,761	4,750	4,740	57,574
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		4,693	4,684	4,674	4,663	4,654	4,643	4,633	4,623	4,613	4,602	4,592	4,582	55,656
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 4,693	$ 4,684	$ 4,674	$ 4,663	$ 4,654	$ 4,643	$ 4,633	$ 4,623	$ 4,613	$ 4,602	$ 4,592	$ 4,582	$ 55,656

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(177,244)	(179,017)	(180,790)	(182,563)	(184,336)	(186,109)	(187,882)	(189,655)	(191,428)	(193,201)	(194,974)	(196,747)	(198,520)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 641,157	639,384	637,611	635,838	634,065	632,292	630,519	628,746	626,973	625,200	623,427	621,654	619,881	
6.	Average Net Investment		640,271	638,498	636,725	634,952	633,179	631,406	629,633	627,860	626,087	624,314	622,541	620,768	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,708	4,695	4,682	4,669	4,656	4,643	4,630	4,617	4,604	4,591	4,578	4,565	$ 55,638
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,505	1,500	1,496	1,492	1,488	1,484	1,480	1,475	1,471	1,467	1,463	1,459	17,780
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)		7,986	7,968	7,951	7,934	7,917	7,900	7,883	7,865	7,848	7,831	7,814	7,797	94,694
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,986	7,968	7,951	7,934	7,917	7,900	7,883	7,865	7,848	7,831	7,814	7,797	94,694
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		7,720	7,702	7,686	7,670	7,653	7,637	7,620	7,603	7,586	7,570	7,554	7,537	91,538
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 7,720	$ 7,702	$ 7,686	$ 7,670	$ 7,653	$ 7,637	$ 7,620	$ 7,603	$ 7,586	$ 7,570	$ 7,554	$ 7,537	$ 91,538

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(17,388)	(17,531)	(17,674)	(17,817)	(17,960)	(18,103)	(18,246)	(18,389)	(18,532)	(18,675)	(18,818)	(18,961)	(19,104)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 39,889	39,746	39,603	39,460	39,317	39,174	39,031	38,888	38,745	38,602	38,459	38,316	38,173	
6.	Average Net Investment		39,818	39,675	39,532	39,389	39,246	39,103	38,960	38,817	38,674	38,531	38,388	38,245	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		293	292	291	290	289	288	286	285	284	283	282	281	$ 3,444
	b. Debt Component (Line 6 x 2.82% x 1/12)		94	93	93	93	92	92	92	91	91	91	90	90	1,102
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)		530	528	527	526	524	523	521	519	518	517	515	514	6,262
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		530	528	527	526	524	523	521	519	518	517	515	514	6,262
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		512	510	509	508	507	506	504	502	501	500	498	497	6,054
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 512	$ 510	$ 509	$ 508	$ 507	$ 506	$ 504	$ 502	$ 501	$ 500	$ 498	$ 497	$ 6,054

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(27,875)	(28,101)	(28,327)	(28,553)	(28,779)	(29,005)	(29,231)	(29,457)	(29,683)	(29,909)	(30,135)	(30,361)	(30,587)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$62,597	62,371	62,145	61,919	61,693	61,467	61,241	61,015	60,789	60,563	60,337	60,111	59,885	
6.	Average Net Investment		62,484	62,258	62,032	61,806	61,580	61,354	61,128	60,902	60,676	60,450	60,224	59,998	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		459	458	456	454	453	451	449	448	446	444	443	441	$ 5,402
	b. Debt Component (Line 6 x 2.82% x 1/12)		147	146	146	145	145	144	144	143	143	142	142	141	1,728
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)		832	830	828	825	824	821	819	817	815	812	811	808	9,842
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		832	830	828	825	824	821	819	817	815	812	811	808	9,842
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		804	802	800	798	797	794	792	790	788	785	784	781	9,515
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$804	$802	$800	$798	$797	$794	$792	$790	$788	$785	$784	$781	$ 9,515

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(388,712)	(392,332)	(395,952)	(399,572)	(403,192)	(406,812)	(410,432)	(414,052)	(417,672)	(421,292)	(424,912)	(428,532)	(432,152)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 927,545	923,925	920,305	916,685	913,065	909,445	905,825	902,205	898,585	894,965	891,345	887,725	884,105	
6.	Average Net Investment		925,735	922,115	918,495	914,875	911,255	907,635	904,015	900,395	896,775	893,155	889,535	885,915	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,807	6,780	6,754	6,727	6,701	6,674	6,647	6,621	6,594	6,568	6,541	6,514	$ 79,928
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,175	2,167	2,158	2,150	2,141	2,133	2,124	2,116	2,107	2,099	2,090	2,082	25,542
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)		12,602	12,567	12,532	12,497	12,462	12,427	12,391	12,357	12,321	12,287	12,251	12,216	148,910
	a. Recoverable Costs Allocated to Energy		12,602	12,567	12,532	12,497	12,462	12,427	12,391	12,357	12,321	12,287	12,251	12,216	148,910
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		12,288	12,056	12,155	11,951	11,982	12,008	11,932	11,851	11,935	11,742	11,879	11,839	143,618
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)		$ 12,288	$ 12,056	$ 12,155	$ 11,951	$ 11,982	$ 12,008	$ 11,932	$ 11,851	$ 11,935	$ 11,742	$ 11,879	$ 11,839	$ 143,618

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(307,638)	(310,182)	(312,726)	(315,270)	(317,814)	(320,358)	(322,902)	(325,446)	(327,990)	(330,534)	(333,078)	(335,622)	(338,166)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 677,156	674,612	672,068	669,524	666,980	664,436	661,892	659,348	656,804	654,260	651,716	649,172	646,628	
6.	Average Net Investment		675,884	673,340	670,796	668,252	665,708	663,164	660,620	658,076	655,532	652,988	650,444	647,900	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,970	4,951	4,932	4,914	4,895	4,876	4,858	4,839	4,820	4,802	4,783	4,764	$ 58,404
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,588	1,582	1,576	1,570	1,564	1,558	1,552	1,546	1,541	1,535	1,529	1,523	18,664
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)		9,102	9,077	9,052	9,028	9,003	8,978	8,954	8,929	8,905	8,881	8,856	8,831	107,596
	a. Recoverable Costs Allocated to Energy		9,102	9,077	9,052	9,028	9,003	8,978	8,954	8,929	8,905	8,881	8,856	8,831	107,596
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		8,876	8,708	8,779	8,634	8,656	8,675	8,623	8,563	8,626	8,487	8,587	8,558	103,772
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)		$ 8,876	$ 8,708	$ 8,779	$ 8,634	$ 8,656	$ 8,675	$ 8,623	$ 8,563	$ 8,626	$ 8,487	$ 8,587	$ 8,558	$ 103,772

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(18,823)	(19,024)	(19,225)	(19,426)	(19,627)	(19,828)	(20,029)	(20,230)	(20,431)	(20,632)	(20,833)	(21,034)	(21,235)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 101,914	101,713	101,512	101,311	101,110	100,909	100,708	100,507	100,306	100,105	99,904	99,703	99,502	
6.	Average Net Investment		101,814	101,613	101,412	101,211	101,010	100,809	100,608	100,407	100,206	100,005	99,804	99,603	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		749	747	746	744	743	741	740	738	737	735	734	732	$ 8,886
	b. Debt Component (Line 6 x 2.82% x 1/12)		239	239	238	238	237	237	236	236	235	235	235	234	2,839
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)		1,189	1,187	1,185	1,183	1,181	1,179	1,177	1,175	1,173	1,171	1,170	1,167	14,137
	a. Recoverable Costs Allocated to Energy		1,189	1,187	1,185	1,183	1,181	1,179	1,177	1,175	1,173	1,171	1,170	1,167	14,137
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		1,159	1,139	1,149	1,131	1,136	1,139	1,133	1,127	1,136	1,119	1,134	1,131	13,633
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)		$ 1,159	$ 1,139	$ 1,149	$ 1,131	$ 1,136	$ 1,139	$ 1,133	$ 1,127	$ 1,136	$ 1,119	$ 1,134	$ 1,131	$ 13,633

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$1,359	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$ 1,359
	b. Clearings to Plant		234,029	0	0	0	0	0	0	0	0	0	0	0	234,029
	c. Retirements		0	0	0	0	0	0	0	0	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)	$ 83,318,932	$ 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	$ 83,552,961	
3.	*Less: Accumulated Depreciation*	(24,498,151)	(24,699,729)	(24,901,532)	(25,103,335)	(25,305,138)	(25,506,941)	(25,708,744)	(25,910,547)	(26,112,350)	(26,314,153)	(26,515,956)	(26,717,759)	(26,919,562)	
4.	CWIP - Non-Interest Bearing	232,670	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$ 59,053,451	58,853,232	58,651,429	58,449,626	58,247,823	58,046,020	57,844,217	57,642,414	57,440,611	57,238,808	57,037,005	56,835,202	56,633,399	
6.	Average Net Investment		58,953,341	58,752,330	58,550,527	58,348,724	58,146,921	57,945,118	57,743,315	57,541,512	57,339,709	57,137,906	56,936,103	56,734,300	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		433,494	432,016	430,532	429,048	427,564	426,080	424,596	423,112	421,628	420,145	418,661	417,177	$ 5,104,053
	b. Debt Component (Line 6 x 2.82% x 1/12)		138,540	138,068	137,594	137,120	136,645	136,171	135,697	135,223	134,748	134,274	133,800	133,326	1,631,206
8.	Investment Expenses														
	a. Depreciation (D)		201,578	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	2,421,411
	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)		773,612	771,887	769,929	767,971	766,012	764,054	762,096	760,138	758,179	756,222	754,264	752,306	9,156,670
	a. Recoverable Costs Allocated to Energy		773,612	771,887	769,929	767,971	766,012	764,054	762,096	760,138	758,179	756,222	754,264	752,306	9,156,670
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		754,365	740,500	746,743	734,426	736,509	738,267	733,894	729,000	734,447	722,683	731,356	729,085	8,831,275
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)		$ 754,365	$ 740,500	$ 746,743	$ 734,426	$ 736,509	$ 738,267	$ 733,894	$ 729,000	$ 734,447	$ 722,683	$ 731,356	$ 729,085	$ 8,831,275

Notes:

(A) Applicable depreciable base for Big Bend; account 312.46 ($83,318,932) and 312.45 ($234,029)
(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% and 2.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(3,032,677)	(3,074,319)	(3,115,961)	(3,157,603)	(3,199,245)	(3,240,887)	(3,282,529)	(3,324,171)	(3,365,813)	(3,407,455)	(3,449,097)	(3,490,739)	(3,532,381)	
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) (B)	$ 18,707,060	18,665,418	18,623,776	18,582,134	18,540,492	18,498,850	18,457,208	18,415,566	18,373,924	18,332,282	18,290,640	18,248,998	18,207,356	
6.	Average Net Investment		18,686,239	18,644,597	18,602,955	18,561,313	18,519,671	18,478,029	18,436,387	18,394,745	18,353,103	18,311,461	18,269,819	18,228,177	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		137,403	137,097	136,791	136,484	136,178	135,872	135,566	135,260	134,953	134,647	134,341	134,035	$ 1,628,627
	b. Debt Component (Line 6 x 2.82% x 1/12)		43,913	43,815	43,717	43,619	43,521	43,423	43,326	43,228	43,130	43,032	42,934	42,836	520,494
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)*		222,958	222,554	222,150	221,745	221,341	220,937	220,534	220,130	219,725	219,321	218,917	218,513	2,648,825
	a. Recoverable Costs Allocated to Energy		222,958	222,554	222,150	221,745	221,341	220,937	220,534	220,130	219,725	219,321	218,917	218,513	2,648,825
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		217,411	213,504	215,460	212,059	212,816	213,480	212,373	211,113	212,847	209,594	212,268	211,768	2,554,693
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)		$ 217,411	$ 213,504	$ 215,460	$ 212,059	$ 212,816	$ 213,480	$ 212,373	$ 211,113	$ 212,847	$ 209,594	$ 212,268	$ 211,768	$ 2,554,693

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	2,937,357	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	231,010	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$ 6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$ 6,128,210	$ 6,128,210	$ 3,190,853	$ 3,190,853	$3,190,853	$ 3,190,853	$ 3,190,853	
3.	Less: Accumulated Depreciation	(231,803)	(247,730)	(263,657)	(279,584)	(295,511)	(311,438)	(327,365)	(343,292)	2,812,942	2,804,603	2,796,264	2,787,925	2,779,586	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$ 5,896,407	5,880,480	5,864,553	5,848,626	5,832,699	5,816,772	5,800,845	5,784,918	6,003,795	5,995,456	5,987,117	5,978,778	5,970,439	
6.	Average Net Investment		5,888,444	5,872,517	5,856,590	5,840,663	5,824,736	5,808,809	5,792,882	5,894,357	5,999,626	5,991,287	5,982,948	5,974,609	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		43,299	43,182	43,064	42,947	42,830	42,713	42,596	43,342	44,116	44,055	43,994	43,932	$ 520,070
	b. Debt Component (Line 6 x 2.82% x 1/12)		13,838	13,800	13,763	13,726	13,688	13,651	13,613	13,852	14,099	14,080	14,060	14,040	166,210
8.	Investment Expenses														
	a. Depreciation (D)		15,927	15,927	15,927	15,927	15,927	15,927	15,927	12,133	8,339	8,339	8,339	8,339	156,978
	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)		73,064	72,909	72,754	72,600	72,445	72,291	72,136	69,327	66,554	66,474	66,393	66,311	843,258
	a. Recoverable Costs Allocated to Energy		73,064	72,909	72,754	72,600	72,445	72,291	72,136	69,327	66,554	66,474	66,393	66,311	843,258
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		71,246	69,944	70,563	69,429	69,655	69,851	69,467	66,487	64,471	63,526	64,377	64,264	813,280
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)		$ 71,246	$ 69,944	$ 70,563	$ 69,429	$ 69,655	$ 69,851	$ 69,467	$ 66,487	$ 64,471	$ 63,526	$ 64,377	$ 64,264	$ 813,280

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,964)
(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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ECRC 2007 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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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)	$ 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	(483,639)	(503,834)	(524,029)	(544,224)	(564,419)	(584,614)	(604,809)	(625,004)	(645,199)	(665,394)	(685,589)	(705,784)	(725,979)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$ 7,507,413	7,487,218	7,467,023	7,446,828	7,426,633	7,406,438	7,386,243	7,366,048	7,345,853	7,325,658	7,305,463	7,285,268	7,265,073	
6.	Average Net Investment		7,497,316	7,477,121	7,456,926	7,436,731	7,416,536	7,396,341	7,376,146	7,355,951	7,335,756	7,315,561	7,295,366	7,275,171	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		55,129	54,981	54,832	54,684	54,535	54,387	54,238	54,090	53,941	53,793	53,644	53,496	$ 651,750
	b. Debt Component (Line 6 x 2.82% x 1/12)		17,619	17,571	17,524	17,476	17,429	17,381	17,334	17,286	17,239	17,192	17,144	17,097	208,292
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)		92,943	92,747	92,551	92,355	92,159	91,963	91,767	91,571	91,375	91,180	90,983	90,788	1,102,382
	a. Recoverable Costs Allocated to Energy		92,943	92,747	92,551	92,355	92,159	91,963	91,767	91,571	91,375	91,180	90,983	90,788	1,102,382
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		90,631	88,976	89,764	88,321	88,609	88,859	88,371	87,820	88,515	87,136	88,220	87,986	1,063,208
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)		$ 90,631	$ 88,976	$ 89,764	$ 88,321	$ 88,609	$ 88,859	$ 88,371	$ 87,820	$ 88,515	$ 87,136	$ 88,220	$ 87,986	$ 1,063,208

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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*	(152,442)	(156,866)	(161,290)	(165,714)	(170,138)	(174,562)	(178,986)	(183,410)	(187,834)	(192,258)	(196,682)	(201,106)	(205,530)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 1,409,031	1,404,607	1,400,183	1,395,759	1,391,335	1,386,911	1,382,487	1,378,063	1,373,639	1,369,215	1,364,791	1,360,367	1,355,943	
6.	Average Net Investment		1,406,819	1,402,395	1,397,971	1,393,547	1,389,123	1,384,699	1,380,275	1,375,851	1,371,427	1,367,003	1,362,579	1,358,155	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,345	10,312	10,280	10,247	10,214	10,182	10,149	10,117	10,084	10,052	10,019	9,987	$ 121,988
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,306	3,296	3,285	3,275	3,264	3,254	3,244	3,233	3,223	3,212	3,202	3,192	38,986
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)		18,075	18,032	17,989	17,946	17,902	17,860	17,817	17,774	17,731	17,688	17,645	17,603	214,062
	a. Recoverable Costs Allocated to Energy		18,075	18,032	17,989	17,946	17,902	17,860	17,817	17,774	17,731	17,688	17,645	17,603	214,062
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		17,625	17,299	17,447	17,162	17,212	17,257	17,158	17,046	17,176	16,904	17,109	17,060	206,455
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)		$ 17,625	$ 17,299	$ 17,447	$ 17,162	$ 17,212	$ 17,257	$ 17,158	$ 17,046	$ 17,176	$ 16,904	$ 17,109	$ 17,060	$ 206,455

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	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	(141,830)	(146,947)	(152,064)	(157,181)	(162,298)	(167,415)	(172,532)	(177,649)	(182,766)	(187,883)	(193,000)	(198,117)	(203,234)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 2,416,900	2,411,783	2,406,666	2,401,549	2,396,432	2,391,315	2,386,198	2,381,081	2,375,964	2,370,847	2,365,730	2,360,613	2,355,496	
6.	Average Net Investment		2,414,342	2,409,225	2,404,108	2,398,991	2,393,874	2,388,757	2,383,640	2,378,523	2,373,406	2,368,289	2,363,172	2,358,055	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		17,753	17,715	17,678	17,640	17,603	17,565	17,527	17,490	17,452	17,414	17,377	17,339	$ 210,553
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,674	5,662	5,650	5,638	5,626	5,614	5,602	5,590	5,578	5,565	5,553	5,541	67,293
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)		28,544	28,494	28,445	28,395	28,346	28,296	28,246	28,197	28,147	28,096	28,047	27,997	339,250
	a. Recoverable Costs Allocated to Energy		28,544	28,494	28,445	28,395	28,346	28,296	28,246	28,197	28,147	28,096	28,047	27,997	339,250
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		27,834	27,335	27,588	27,155	27,254	27,341	27,201	27,042	27,266	26,850	27,195	27,133	327,194
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)		$ 27,834	$ 27,335	$ 27,588	$ 27,155	$ 27,254	$ 27,341	$ 27,201	$ 27,042	$ 27,266	$ 26,850	$ 27,195	$ 27,133	$ 327,194

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: *Big Bend Unit 1 Pre-SCR*
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. *Expenditures/Additions*		$ 433	$ (3,744)	$ 630	$ 369	$ 362	$ 356	$ 372	$ 414	$ 385	$ 491	$ 1,995	$ 147	$ 2,210
	b. Clearings to Plant		1,653,621	(4,500)	0	0	0	0	0	0	0	0	0	0	1,649,121
	c. Retirements		0	0	0	0	0	0	0	0	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	$ 1,653,621	$ 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	0	(2,274)	(6,815)	(11,350)	(15,885)	(20,420)	(24,955)	(29,490)	(34,025)	(38,560)	(43,095)	(47,630)	(52,165)	
4.	CWIP - Non-Interest Bearing	2,014,682	361,494	362,250	362,880	363,249	363,611	363,967	364,339	364,753	365,138	365,629	367,624	367,771	
5.	Net Investment (Lines 2 + 3 + 4)	$ 2,014,682	2,012,841	2,004,556	2,000,651	1,996,485	1,992,312	1,988,133	1,983,970	1,979,849	1,975,699	1,971,655	1,969,115	1,964,727	
6.	Average Net Investment		2,013,762	2,008,699	2,002,604	1,998,568	1,994,399	1,990,223	1,986,052	1,981,910	1,977,774	1,973,677	1,970,385	1,966,921	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,808	14,770	14,725	14,696	14,665	14,634	14,604	14,573	14,543	14,513	14,489	14,463	$ 175,483
	b. Debt Component (Line 6 x 2.82% x 1/12)		4,732	4,720	4,706	4,697	4,687	4,677	4,667	4,657	4,648	4,638	4,630	4,622	56,081
8.	Investment Expenses														
	a. Depreciation (C)		2,274	4,541	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	52,165
	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)		21,814	24,031	23,966	23,928	23,887	23,846	23,806	23,765	23,726	23,686	23,654	23,620	283,729
	a. Recoverable Costs Allocated to Energy		21,814	24,031	23,966	23,928	23,887	23,846	23,806	23,765	23,726	23,686	23,654	23,620	283,729
	b. *Recoverable Costs Allocated to Demand*		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		21,271	23,054	23,244	22,883	22,967	23,041	22,925	22,791	22,983	22,636	22,936	22,891	273,622
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)		$ 21,271	$ 23,054	$ 23,244	$ 22,883	$ 22,967	$ 23,041	$ 22,925	$ 22,791	$ 22,983	$ 22,636	$ 22,936	$ 22,891	$ 273,622

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		($13,317)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$ (13,317)
	b. Clearings to Plant		1,581,887	0	0	0	0	0	0	0	0	0	0	0	$ 1,581,887
	c. Retirements		0	0	0	0	0	0	0	0	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	$ 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	0	(2,043)	(6,130)	(10,217)	(14,304)	(18,391)	(22,478)	(26,565)	(30,652)	(34,739)	(38,826)	(42,913)	(47,000)	
4.	CWIP - Non-Interest Bearing	1,595,204	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$ 1,595,204	1,579,844	1,575,757	1,571,670	1,567,583	1,563,496	1,559,409	1,555,322	1,551,235	1,547,148	1,543,061	1,538,974	1,534,887	
6.	Average Net Investment		1,587,524	1,577,801	1,573,714	1,569,627	1,565,540	1,561,453	1,557,366	1,553,279	1,549,192	1,545,105	1,541,018	1,536,931	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		11,673	11,602	11,572	11,542	11,512	11,482	11,452	11,422	11,391	11,361	11,331	11,301	$ 137,641
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,731	3,708	3,698	3,689	3,679	3,669	3,660	3,650	3,641	3,631	3,621	3,612	43,989
8.	Investment Expenses														
	a. Depreciation (C)		2,043	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	47,000
	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)		17,447	19,397	19,357	19,318	19,278	19,238	19,199	19,159	19,119	19,079	19,039	19,000	228,630
	a. Recoverable Costs Allocated to Energy		17,447	19,397	19,357	19,318	19,278	19,238	19,199	19,159	19,119	19,079	19,039	19,000	228,630
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		17,013	18,608	18,774	18,474	18,535	18,589	18,489	18,374	18,521	18,233	18,461	18,414	220,485
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)		$ 17,013	$ 18,608	$ 18,774	$ 18,474	$ 18,535	$ 18,589	$ 18,489	$ 18,374	$ 18,521	$ 18,233	$ 18,461	$ 18,414	$ 220,485

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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$67,721	($292)	$64,850	$7,078	$0	($373)	$255,338	$2,117	$2,859	$7,896	$974,709	$40,254	$ 1,422,157
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	710,718	778,439	778,147	842,997	850,075	850,075	849,702	1,105,040	1,107,157	1,110,016	1,117,912	2,092,621	2,132,875	
5.	Net Investment (Lines 2 + 3 + 4)	$ 710,718	778,439	778,147	842,997	850,075	850,075	849,702	1,105,040	1,107,157	1,110,016	1,117,912	2,092,621	2,132,875	
6.	Average Net Investment		744,579	778,293	810,572	846,536	850,075	849,889	977,371	1,106,099	1,108,587	1,113,964	1,605,267	2,112,748	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,475	5,723	5,960	6,225	6,251	6,249	7,187	8,133	8,152	8,191	11,804	15,535	$ 94,885
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,750	1,829	1,905	1,989	1,998	1,997	2,297	2,599	2,605	2,618	3,772	4,965	30,324
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)		7,225	7,552	7,865	8,214	8,249	8,246	9,484	10,732	10,757	10,809	15,576	20,500	125,209
	a. Recoverable Costs Allocated to Energy		7,225	7,552	7,865	8,214	8,249	8,246	9,484	10,732	10,757	10,809	15,576	20,500	125,209
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		7,045	7,245	7,628	7,855	7,931	7,968	9,133	10,292	10,420	10,330	15,103	19,867	120,817
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)		$ 7,045	$ 7,245	$ 7,628	$ 7,855	$ 7,931	$ 7,968	$ 9,133	$ 10,292	$ 10,420	$ 10,330	$ 15,103	$ 19,867	$ 120,817

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43
(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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$ 1,189,709	$ 1,394,762	$ 1,841,932	$ 903,592	$ 1,304,902	$ 1,041,502	$ 1,057,830	$ 996,886	$ 1,091,611	$ 1,175,411	$ 1,013,399	$ 1,042,637	$ 14,054,173
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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)	$ 7,504,877	$8,694,586	$10,089,348	$11,931,280	$12,834,872	$14,139,774	$15,181,276	$16,239,106	$17,235,992	$18,327,603	$19,503,014	$20,516,413	$21,559,050	
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)	$ 7,504,877	8,694,586	10,089,348	11,931,280	12,834,872	14,139,774	15,181,276	16,239,106	17,235,992	18,327,603	19,503,014	20,516,413	21,559,050	
6.	Average Net Investment		8,099,732	9,391,967	11,010,314	12,383,076	13,487,323	14,660,525	15,710,191	16,737,549	17,781,798	18,915,309	20,009,714	21,037,732	
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		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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) Commission 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 Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	*End of Period Total*
1.	Investments														
	a. Expenditures/Additions		$ 2,169,237	$ 1,966,611	$ 1,549,258	$ 826,974	$ 3,161,956	$ 1,416,687	$ 889,343	$ 3,112,154	$ 1,852,770	$ 713,083	$ 1,748,100	$ 2,014,396	$ 21,420,569
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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)	$ 7,634,814	$ 9,804,051	$ 11,770,662	$ 13,319,920	$ 14,146,894	$ 17,308,850	$ 18,725,537	$ 19,614,880	$ 22,727,034	$ 24,579,804	$ 25,292,887	$ 27,040,987	$ 29,055,383	
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)	$ 7,634,814	9,804,051	11,770,662	13,319,920	14,146,894	17,308,850	18,725,537	19,614,880	22,727,034	24,579,804	25,292,887	27,040,987	29,055,383	
6.	Average Net Investment		8,719,433	10,787,357	12,545,291	13,733,407	15,727,872	18,017,194	19,170,209	21,170,957	23,653,419	24,936,346	26,166,937	28,048,185	
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		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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 rates are 3.3% and 2.5%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Commission 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 Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$ 5,543,583	$ 3,739,520	$ 1,899,292	$ 3,622,534	$ 3,376,444	$ 3,027,856	$ 2,120,137	$ 2,936,350	$ 2,389,104	$ 2,509,923	$ 3,727,408	$ 2,023,372	$ 36,915,523
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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)	$ 28,867,509	$ 34,411,092	$ 38,150,612	$ 40,049,904	$ 43,672,438	$ 47,048,882	$ 50,076,738	$ 52,196,875	$ 55,133,225	$ 57,522,329	$ 60,032,252	$ 63,759,660	$ 65,783,032	
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)	$ 28,867,509	34,411,092	38,150,612	40,049,904	43,672,438	47,048,882	50,076,738	52,196,875	55,133,225	57,522,329	60,032,252	63,759,660	65,783,032	
6.	Average Net Investment		31,639,301	36,280,852	39,100,258	41,861,171	45,360,660	48,562,810	51,136,807	53,665,050	56,327,777	58,777,291	61,895,956	64,771,346	
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		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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 rates are 3.3% and 2.5%
(D) Line 9a x Line 10
(F) Commission 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 Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$ 1,001,114	$ 1,240,693	$ 2,246,617	$ 274,912	$ 843,768	$ 740,518	$ 239,086	$ 256,731	$ (23,359)	$ (265,818)	$ 187,447	$ 47,964	$ 6,789,873
	b. Clearings to Plant		0	0	0	0	59,973,427	719,053	213,239	358,762	(23,359)	(265,818)	187,447	47,964	61,210,715
	c. Retirements		0	0	0	0	0	0	0	0	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)	$ 51,686,174	$ 52,687,288	$ 53,927,981	$ 56,174,798	$ 56,449,710	$ 59,973,427	$ 60,692,480	$ 60,905,719	$ 61,264,481	$ 61,241,122	$ 60,975,304	$ 61,162,751	$ 61,210,715	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(59,973)	(180,639)	(302,237)	(424,407)	(546,913)	(669,129)	(791,267)	(913,640)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	*Net Investment (Lines 2 + 3 + 4)*	$ 51,686,174	52,687,288	53,927,981	56,174,798	56,449,710	59,913,454	60,511,841	60,603,482	60,840,074	60,694,209	60,306,175	60,371,484	60,297,075	
6.	Average Net Investment		52,186,731	53,307,635	55,051,390	56,312,254	58,181,582	60,212,648	60,557,662	60,721,778	60,767,142	60,500,192	60,338,830	60,334,280	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	82,804	442,754	445,291	446,497	446,831	444,868	443,681	443,648	$ 3,196,374
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	26,463	141,500	142,311	142,696	142,803	142,175	141,796	141,786	1,021,530
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	59,973	120,666	121,598	122,170	122,506	122,216	122,138	122,373	913,640
	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	169,240	704,920	709,200	711,363	712,140	709,259	707,615	707,807	5,131,544
	a. Recoverable Costs Allocated to Energy		0	0	0	0	169,240	704,920	709,200	711,363	712,140	709,259	707,615	707,807	5,131,544
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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	162,722	681,129	682,956	682,223	689,849	677,803	686,124	685,960	4,948,766
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	$162,722	$681,129	$682,956	$682,223	$689,849	$677,803	$686,124	$685,960	$ 4,948,766

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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$ 174,114	$ 1,348,917	$ 2,219,239	$ 351,809	$ 600,111	$ 161,088	$ 183,879	$ 221,435	$ 105,313	$ 181,956	$ 952,234	$ 1,790,986	$ 8,291,081
	b. Clearings to Plant		0	0	0	0	4,815,699	30,093	130,932	17,841	5,748	422	869	0	5,001,604
	c. Retirements		0	0	0	0	0	0	0	0	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	$4,815,699	$4,845,792	$4,976,724	$4,994,565	$5,000,313	$5,000,735	$5,001,604	$5,001,604	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(4,615)	(13,874)	(23,287)	(32,843)	(42,421)	(52,005)	(61,591)	(71,177)	
4.	CWIP - Non-Interest Bearing	1,770,578	1,944,692	3,293,609	5,512,848	5,864,657	1,649,069	1,780,064	1,833,011	2,036,605	2,136,170	2,317,704	3,269,069	5,060,055	
5.	Net Investment (Lines 2 + 3 + 4)	$ 1,770,578	1,944,692	3,293,609	5,512,848	5,864,657	6,460,153	6,611,982	6,786,448	6,998,327	7,094,062	7,266,434	8,209,082	9,990,482	
6.	Average Net Investment		1,857,635	2,619,151	4,403,229	5,688,753	6,162,405	6,536,068	6,699,215	6,892,388	7,046,195	7,180,248	7,737,758	9,099,782	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		13,659	19,259	32,378	41,830	45,313	48,061	49,260	50,681	51,812	52,798	56,897	66,912	$ 528,860
	b. Debt Component (Line 6 x 2.82% x 1/12)		4,365	6,155	10,348	13,369	14,482	15,360	15,743	16,197	16,559	16,874	18,184	21,384	169,020
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	4,615	9,259	9,413	9,556	9,578	9,584	9,586	9,586	71,177
	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)		18,024	25,414	42,726	55,199	64,410	72,680	74,416	76,434	77,949	79,256	84,667	97,882	769,057
	a. Recoverable Costs Allocated to Energy		18,024	25,414	42,726	55,199	64,410	72,680	74,416	76,434	77,949	79,256	84,667	97,882	769,057
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		17,576	24,381	41,439	52,788	61,929	70,227	71,662	73,303	75,509	75,741	82,096	94,861	741,512
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)		$ 17,576	$ 24,381	$ 41,439	$ 52,788	$ 61,929	$ 70,227	$ 71,662	$ 73,303	$ 75,509	$ 75,741	$ 82,096	$ 94,861	$ 741,512

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

DOCKET NO. 080007-EI
ECRC 2007 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 24 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$167,232	$5,793	$9,370	$11,187	$4,778	$198,360
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	167,232	173,025	182,395	193,582	198,360	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	167,232	173,025	182,395	193,582	198,360	
6.	Average Net Investment		0	0	0	0	0	0	0	83,616	170,129	177,710	187,989	195,971	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	615	1,251	1,307	1,382	1,441	$ 5,996
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	196	400	418	442	461	1,917
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	811	1,651	1,725	1,824	1,902	7,913
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	811	1,651	1,725	1,824	1,902	7,913
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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	778	1,599	1,648	1,769	1,843	7,637
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)		$0	$0	$0	$0	$0	$0	$0	$778	$1,599	$1,648	$1,769	$1,843	$ 7,637

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2007 to December 2007

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	*Investments*														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	1,035,500	11,622,780	4,071,250	6,682,500	22,787,500	9,318,750	12,314,750	6,941,250	14,906,350	89,680,630
	c. Auction Proceeds/Other		0	0	0	0	773,503	0	0	0	0	0	0	0	773,503
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	(832,866)	(782,420)	(778,445)	(775,323)	(763,581)	(666,714)	(633,561)	(591,207)	(412,872)	(341,931)	(231,903)	(178,125)	(69,802)	
3.	Total Working Capital Balance	$ (832,866)	(782,420)	(778,445)	(775,323)	(763,581)	(666,714)	(633,561)	(591,207)	(412,872)	(341,931)	(231,903)	(178,125)	(69,802)	
4.	Average Net Working Capital Balance		$ (807,643)	$ (780,433)	$ (776,884)	$ (769,452)	$ (715,148)	$ (650,138)	$ (612,384)	$ (502,040)	$ (377,402)	$ (286,917)	$ (205,014)	$ (123,964)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(5,939)	(5,739)	(5,713)	(5,658)	(5,259)	(4,781)	(4,503)	(3,692)	(2,775)	(2,110)	(1,508)	(912)	(48,589)
	b. Debt Component (Line 4 x 2.82% x 1/12)		(1,898)	(1,834)	(1,826)	(1,808)	(1,681)	(1,528)	(1,439)	(1,180)	(887)	(674)	(482)	(291)	(15,528)
6.	Total Return Component		(7,837)	(7,573)	(7,539)	(7,466)	(6,940)	(6,309)	(5,942)	(4,872)	(3,662)	(2,784)	(1,990)	(1,203)	(64,117)
7.	Expenses:														
	a. Gains		0	0	0	(1,045,095)	(12,490,851)	(4,100,035)	(6,720,880)	(22,950,615)	(9,385,915)	(12,401,105)	(6,991,144)	(15,011,895)	(91,097,535)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(25,909)	13,178	15,874	16,960	19,851	22,565	24,495	8,905	16,319	(2,853)	9,927	14,976	134,288
8.	Net Expenses (B)		(25,909)	13,178	15,874	(1,028,135)	(12,471,000)	(4,077,470)	(6,696,385)	(22,941,710)	(9,369,596)	(12,403,958)	(6,981,217)	(14,996,919)	(90,963,247)
9.	Total System Recoverable Expenses (Lines 6 + 8)		(33,746)	5,605	8,335	(1,035,601)	(12,477,940)	(4,083,779)	(6,702,327)	(22,946,582)	(9,373,258)	(12,406,742)	(6,983,207)	(14,998,122)	(91,027,364)
	a. Recoverable Costs Allocated to Energy		(33,746)	5,605	8,335	(1,035,601)	(12,477,940)	(4,083,779)	(6,702,327)	(22,946,582)	(9,373,258)	(12,406,742)	(6,983,207)	(14,998,122)	(91,027,364)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9629945	0.9590358	0.9686989	0.9556497	0.9696286	0.9691337	
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)		(32,906)	5,377	8,084	(990,366)	(11,997,343)	(3,945,949)	(6,454,304)	(22,006,594)	(9,079,865)	(11,856,499)	(6,771,117)	(14,535,185)	(87,656,667)
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)		$ (32,906)	$ 5,377	$ 8,084	$ (990,366)	$ (11,997,343)	$ (3,945,949)	$ (6,454,304)	$ (22,006,594)	$ (9,079,865)	$ (11,856,499)	$ (6,771,117)	$ (14,535,185)	$ (87,656,667)

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.

DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL / ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD OF
JANUARY 2008 THROUGH DECEMBER 2008

FORMS 42-1E THROUGH 42-8E

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 21
COMPANY TECO (Direct)
WITNESS Howard T. Bryant (HTB-2)
DATE 11-04-08

DOCKET NO. 080007-EI
ECRC 2008 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 2008 THROUGH DECEMBER 2008

FORMS 42-1E THROUGH 42-8E

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Tampa Electric Company Form 42 - 1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2008 to December 2008
(in Dollars)

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($7,904,300)
2.	Interest Provision (Form 42-2E, Line 6)	157,207
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 2008 to December 2008 (Lines 1 + 2 + 3)	($7,747,093)

Form 42 - 2E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated 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	$1,980,000	$1,969,000	$1,970,000	$1,792,000	$1,546,000	$1,554,000	$20,220,365
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	1,790,707	1,779,707	1,780,707	1,602,707	1,356,707	1,364,713	17,948,855
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	934,271	952,608	(142,256)	828,339	63,219	999,666	(2,465,452)	(1,260,017)	(1,282,291)	(1,293,091)	(1,274,616)	(981,498)	(4,921,118)
	b. Capital Investment Projects (Form 42-7E, Line 9)	2,134,203	2,110,209	2,119,919	2,105,631	2,115,932	2,148,973	2,921,632	3,013,039	3,013,434	3,011,167	3,024,301	3,055,833	30,774,273
	c. Total Jurisdictional ECRC Costs	3,068,474	3,062,817	1,977,663	2,933,970	2,179,151	3,148,639	456,180	1,753,022	1,731,143	1,718,076	1,749,685	2,074,335	25,853,155
5.	Over/Under Recovery (Line 3 - Line 4c)	(1,619,188)	(1,881,920)	(764,793)	(1,625,905)	(763,597)	(1,441,704)	1,334,527	26,685	49,564	(115,369)	(392,978)	(709,622)	(7,904,300)
6.	Interest Provision (Form 42-3E, Line 10)	31,850	20,431	16,270	13,330	10,679	8,022	8,027	9,350	9,795	10,107	10,004	9,342	157,207
7.	Beginning Balance True-Up & Interest Provision	(2,271,510)	(3,669,555)	(5,341,751)	(5,900,981)	(7,324,263)	(7,887,888)	(9,132,277)	(7,600,430)	(7,375,102)	(7,126,450)	(7,042,419)	(7,236,100)	(2,271,510)
	a. Deferred True-Up from January to December 2007 (Order No. PSC-xx-xxxx-FOF-EI)	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653	12,465,653
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)	8,796,098	7,123,902	6,564,672	5,141,390	4,577,765	3,333,376	4,865,223	5,090,551	5,339,203	5,423,234	5,229,553	4,718,560	4,718,560
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)	$8,796,098	$7,123,902	$6,564,672	$5,141,390	$4,577,765	$3,333,376	$4,865,223	$5,090,551	$5,339,203	$5,423,234	$5,229,553	$4,718,560	$4,718,560

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

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)	$10,194,143	$8,796,098	$7,123,902	$6,564,672	$5,141,390	$4,577,765	$3,333,376	$4,865,223	$5,090,551	$5,339,203	$5,423,234	$5,229,553	
2.	Ending True-Up Amount Before Interest	8,764,248	7,103,471	6,548,402	5,128,060	4,567,086	3,325,354	4,857,196	5,081,201	5,329,408	5,413,127	5,219,549	4,709,218	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	18,958,391	15,899,569	13,672,304	11,692,732	9,708,476	7,903,119	8,190,572	9,946,424	10,419,959	10,752,330	10,642,783	9,938,771	
4.	Average True-Up Amount (Line 3 x 1/2)	9,479,196	7,949,785	6,836,152	5,846,366	4,854,238	3,951,560	4,095,286	4,973,212	5,209,980	5,376,165	5,321,392	4,969,386	
5.	Interest Rate (First Day of Reporting Business Month)	4.98%	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.25%	2.25%	2.25%	2.25%	2.25%	
6.	Interest Rate (First Day of Subsequent Business Month)	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.06%	6.17%	5.72%	5.47%	5.27%	4.88%	4.70%	4.50%	4.50%	4.50%	4.50%	4.50%	
8.	Average Interest Rate (Line 7 x 1/2)	4.030%	3.085%	2.860%	2.735%	2.635%	2.440%	2.350%	2.250%	2.250%	2.250%	2.250%	2.250%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.336%	0.257%	0.238%	0.228%	0.220%	0.203%	0.196%	0.188%	0.188%	0.188%	0.188%	0.188%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$31,850	$20,431	$16,270	$13,330	$10,679	$8,022	$8,027	$9,350	$9,795	$10,107	$10,004	$9,342	$157,207

Tampa Electric Company Form 42 - 4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

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	$3,287,684	3,688,900	($401,216)	-10.9%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(18,765,601)	(29,413,430)	10,647,829	36.2%
	d. Big Bend Units 1 & 2 FGD	6,337,155	$7,243,000	(905,845)	-12.5%
	e. Big Bend PM Minimization and Monitoring	438,402	$450,000	(11,598)	-2.6%
	f. Big Bend NO_x Emissions Reduction	512,435	$350,000	162,435	46.4%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	76,005	50,000	26,005	52.0%
	i. Polk NO_x Emissions Reduction	46,667	$65,000	(18,333)	-28.2%
	j. Bayside SCR Consumables	108,068	$70,000	38,068	54.4%
	k. Big Bend Unit 4 SOFA	32,976	50,000	(17,024)	-34.0%
	l. Big Bend Unit 1 Pre-SCR	30,000	75,000	(45,000)	-60.0%
	m. Big Bend Unit 2 Pre-SCR	11,188	75,000	(63,812)	-85.1%
	n. Big Bend Unit 3 Pre-SCR	2	0	2	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	124,395	150,000	(25,605)	-17.1%
	p. Arsenic Groundwater Standard Program	98,651	57,000	41,651	73.1%
	q. Big Bend 4 SCR	1,331,036	1,610,000	(278,964)	-17.3%
	r. Big Bend 3 SCR	1,200,000	1,606,900	(406,900)	-25.3%
2.	*Total Investment Projects - Recoverable Costs*	($5,096,437)	($13,838,130)	$8,741,693	63.2%
3.	Recoverable Costs Allocated to Energy	($5,429,988)	($14,129,630)	$8,699,642	61.6%
4.	Recoverable Costs Allocated to Demand	$333,551	$291,500	$42,051	14.4%

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-07-0922-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company Form 42 - 5E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

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	$248,401	$275,121	$243,730	$227,130	$290,194	$337,808	$321,900	$282,700	$278,100	$281,200	$270,400	$231,000	$3,287,684		$3,287,684
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0												0		0
	c. SO_2 Emissions Allowances	11,881	28,579	(953,364)	17,936	(985,484)	14,792	(3,942,763)	(2,596,266)	(2,588,009)	(2,586,212)	(2,589,994)	(2,596,697)	(16,765,601)		(16,765,601)
	d. *Big Bend Units 1 & 2 FGD*	423,620	382,952	346,081	421,332	449,234	498,635	629,900	524,800	556,900	558,900	599,900	944,900	6,337,155		6,337,155
	e. Big Bend PM Minimization and Monitoring	55,967	32,902	21,123	23,341	20,830	30,439	42,300	42,300	42,300	42,300	42,300	42,300	438,402		438,402
	f. Big Bend NO_x Emissions Reduction	125,150	176,174	21,314	0	33,096	66,702	25,000	25,000	10,000	10,000	10,000	10,000	512,435		512,435
	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	25,195	12,362	10,997	3,450	6,000	6,000	6,000	6,000	0	0	76,005	76,005	
	i. Polk NO_x Reduction	6	4,220	4,656	2,347	1,721	1,717	5,000	5,000	5,000	5,000	7,000	5,000	46,667		46,667
	j. Bayside SCR and Ammonia	8,054	8,852	8,489	0	23,366	0	12,370	12,844	12,607	7,162	7,162	7,162	108,068		108,068
	k. Big Bend Unit 4 SOFA	0	17,661	(17,661)	0	52,492	(19,516)	0	0	0	0	0	0	32,976		32,976
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	5,000	5,000	5,000	5,000	5,000	5,000	30,000		30,000
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	6,188	0	1,000	1,000	1,000	1,000	1,000	0	11,188		11,188
	n. Big Bend Unit 3 Pre-SCR	2	0	0	0	0	0	0	0	0	0	0	0	2		2
	o. Clean Water Act Section 316(b) Phase II Study	(15,310)	29,792	46,229	33,330	2,134	4,221	12,000	12,000	0	0	0	0	124,395	124,395	
	p. Arsenic Groundwater Standard Program	0	0	155	0	27,840	0	0	43,274	13,691	0	0	13,691	98,651	98,651	
	q. Big Bend 4 SCR	73,080	41,212	105,026	134,633	133,185	93,901	125,000	125,000	125,000	125,000	125,000	125,000	1,331,036		1,331,036
	r. Big Bend 3 SCR	0	0	0	0	0	0	200,000	200,000	200,000	200,000	200,000	200,000	1,200,000		1,200,000
2.	Total of O&M Activities	965,351	997,464	(149,026)	872,411	65,793	1,032,148	(2,557,293)	(1,311,348)	(1,332,411)	(1,344,650)	(1,322,232)	(1,012,644)	(5,096,437)	$333,551	($5,429,987)
3.	Recoverable Costs Allocated to Energy	946,161	967,672	(220,605)	826,719	24,822	1,024,477	(2,575,293)	(1,372,622)	(1,352,102)	(1,350,650)	(1,322,232)	(1,026,335)	(5,429,988)		
4.	Recoverable Costs Allocated to Demand	19,190	29,792	71,579	45,692	40,971	7,671	18,000	61,274	19,691	6,000	0	13,691	333,551		
5.	Retail Energy Jurisdictional Factor	0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093			
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 (A)	915,721	923,809	(211,450)	784,170	23,613	992,251	(2,482,852)	(1,319,249)	(1,301,326)	(1,298,891)	(1,274,616)	(994,733)	(5,243,553)		
8.	Jurisdictional Demand Recoverable Costs (B)	18,550	28,799	69,194	44,169	39,606	7,415	17,400	59,232	19,035	5,800	0	13,235	322,435		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$934,271	$952,608	($142,256)	$828,339	$63,219	$999,666	($2,465,452)	($1,260,017)	($1,282,291)	($1,293,091)	($1,274,616)	($981,498)	($4,921,118)		

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

DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 5, PAGE 1 OF 1

Form 42 - 6E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2008 to December 2008

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	$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	8,919,694	8,915,093	4,601	0.1%
	l. Big Bend FGD Optimization and Utilization	2,590,639	2,590,639	0	0.0%
	m. Big Bend NO_x Emissions Reduction	798,805	872,714	(73,909)	-8.5%
	n. Big Bend PM Minimization and Monitoring	1,084,033	1,127,247	(43,214)	-3.8%
	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	279,624	420	0.2%
	r. Big Bend Unit 2 Pre-SCR	224,909	224,909	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	356,032	437,512	(81,480)	-18.6%
	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	5,432,066	8,778,536	(3,346,470)	-38.1%
	w. Big Bend Unit 4 SCR	8,408,013	6,125,701	2,282,312	37.3%
	x. Big Bend FGD System Reliability	1,532,141	1,549,199	(17,058)	-1.1%
	y. Clean Air Mercury Rule	70,383	119,317	(48,934)	-41.0%
	z. SO_2 Emissions Allowances	(5,743)	(9,165)	3,422	37.3%
2.	Total Investment Projects - Recoverable Costs	$32,006,864	$33,327,174	($1,320,310)	-4.0%
3.	Recoverable Costs Allocated to Energy	$31,842,992	$33,163,302	($1,320,310)	-4.0%
4.	Recoverable Costs Allocated to Demand	$163,872	$163,872	$0	0.0%

Notes:
Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-07-0922-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 2008 to December 2008

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	$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	750,347	748,389	746,431	744,473	742,538	741,096	741,085	740,706	739,254	738,092	739,921	747,362	8,919,694		8,919,694
	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	65,943	66,072	66,495	67,263	68,079	68,642	798,805		798,805
	n.	Big Bend PM Minimization and Monitoring	90,591	90,396	90,199	90,004	89,807	89,612	89,451	89,326	89,297	90,248	92,084	93,018	1,084,033		1,084,033
	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	31,516	31,460	31,404	31,348	31,293	31,237	356,032		356,032
	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	814,023	920,624	919,565	921,009	924,680	932,165	5,432,066		5,432,066
	w.	Big Bend Unit 4 SCR	707,557	706,732	705,859	705,392	702,934	700,469	699,388	698,201	697,048	695,930	694,811	693,692	8,408,013		8,408,013
	x.	Big Bend FGD System Reliability	110,065	114,980	117,554	125,303	132,098	132,395	132,600	132,998	133,334	133,550	133,648	133,616	1,532,141		1,532,141
	y.	Clean Air Mercury Rule	1,934	3,617	5,799	6,334	6,383	6,412	6,417	6,417	6,417	6,417	6,417	7,819	70,383		70,383
	z.	SO_2 Emissions Allowances (B)	(648)	(616)	(603)	(590)	(577)	(564)	(515)	(438)	(381)	(326)	(270)	(215)	(5,743)		(5,743)
2.		Total Investment Projects - Recoverable Costs	2,205,165	2,210,229	2,211,584	2,219,621	2,224,009	2,218,793	3,030,374	3,134,859	3,130,954	3,131,086	3,137,242	3,152,948	32,006,864	$ 163,872	$ 31,842,992
3.		Recoverable Costs Allocated to Energy	2,191,337	2,196,433	2,197,820	2,205,886	2,210,307	2,205,121	3,016,733	3,121,250	3,117,377	3,117,538	3,123,727	3,139,463	31,842,992		
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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093			
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)	2,120,836	2,096,873	2,106,614	2,092,354	2,102,687	2,135,757	2,908,446	2,999,884	3,000,309	2,998,070	3,011,236	3,042,797	30,615,863		
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)	$2,134,203	$2,110,209	$2,119,919	$2,105,631	$2,115,932	$2,148,973	$2,921,632	$3,013,039	$3,013,434	$3,011,167	$3,024,301	$3,055,833	$30,774,273		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Project's Total Return Component on Form 42-8E, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 7, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	64,851	64,503	64,444	64,246	64,253	64,452	776,569
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	$64,851	$64,503	$64,444	$64,246	$64,253	$64,452	$776,569

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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	(2,373,494)	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	36,849	36,610	36,534	36,381	36,342	36,414	441,495
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	$36,849	$36,610	$36,534	$36,381	$36,342	$36,414	$441,495

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

DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 2 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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	(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 (C)		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 (D)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,973	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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)		6,749	6,643	6,655	6,572	6,577	6,683	6,637	6,603	6,598	6,579	6,580	6,601	79,477
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,749	$6,643	$6,655	$6,572	$6,577	$6,683	$6,637	$6,603	$6,598	$6,579	$6,580	$6,601	$79,477

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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 Current Period Actual / Estimated Amount
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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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 Current Period Actual / Estimated Amount
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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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

DOCKET NO. 080007-EI
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 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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	11,540	11,471	11,453	11,410	11,403	11,432	138,236
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	$11,540	$11,471	$11,453	$11,410	$11,403	$11,432	$138,236

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	8,347	8,297	8,286	8,255	8,251	8,272	99,986
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	$8,347	$8,297	$8,286	$8,255	$8,251	$8,272	$99,986

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 Current Period Actual / Estimated Amount
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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	1,113	1,107	1,107	1,104	1,105	1,109	13,318
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	$1,113	$1,107	$1,107	$1,104	$1,105	$1,109	$13,318

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 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 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	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	$4,739	$101,681	$299,643	$25,875	$78,289	$86,030	$694,484	$1,242,861	$2,533,602
	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)	$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	$83,552,961	$83,552,961	
3.	Less: Accumulated Depreciation	(26,919,562)	(27,121,365)	(27,323,168)	(27,524,971)	(27,726,774)	(27,928,577)	(28,130,380)	(28,332,183)	(28,533,986)	(28,735,789)	(28,937,592)	(29,139,395)	(29,341,198)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	4,739	106,420	406,063	431,938	510,227	596,257	1,290,741	2,533,602	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$56,633,399	56,431,596	56,229,793	56,027,990	55,826,187	55,629,122	55,529,000	55,626,840	55,450,912	55,327,398	55,211,625	55,704,306	56,745,364	
6.	Average Net Investment		56,532,497	56,330,694	56,128,891	55,927,088	55,727,655	55,579,061	55,577,920	55,538,876	55,389,155	55,269,512	55,457,966	56,224,835	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		415,693	414,209	412,725	411,241	409,775	408,682	408,674	408,387	407,286	406,406	407,792	413,431	$4,924,301
	b. Debt Component (Line 6 x 2.82% x 1/12)		132,851	132,377	131,903	131,429	130,960	130,611	130,608	130,516	130,165	129,883	130,326	132,128	1,573,757
8.	Investment Expenses														
	a. Depreciation (D)		201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	2,421,636
	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)		750,347	748,389	746,431	744,473	742,538	741,096	741,085	740,706	739,254	738,092	739,921	747,362	8,919,694
	a. Recoverable Costs Allocated to Energy		750,347	748,389	746,431	744,473	742,538	741,096	741,085	740,706	739,254	738,092	739,921	747,362	8,919,694
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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)		726,206	714,466	715,455	706,157	706,384	717,784	714,484	711,905	711,492	709,807	713,275	724,350	8,571,765
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)		$726,206	$714,466	$715,455	$706,157	$706,384	$717,784	$714,484	$711,905	$711,492	$709,807	$713,275	$724,350	$8,571,765

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46 ($83,318,932) and 312.45 ($234,029)
(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% 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 Current Period Actual / Estimated Amount
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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	207,942	206,909	206,807	206,254	206,360	207,085	2,489,546
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	$207,942	$206,909	$206,807	$206,254	$206,360	$207,085	$2,489,546

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 Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$2,745	$2,352	$2,803	$17,652	$17,652	$67,652	$75,652	$76,129	$33,248	$295,885
	b. Clearings to Plant		0	0	0	2,745	2,352	2,803	17,652	17,652	67,652	75,652	76,129	33,248	$295,885
	c. Retirements		0	0	0	0	0	0	0	0	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	$3,195,949	$3,198,753	$3,216,405	$3,234,057	$3,301,709	$3,377,361	$3,453,490	$3,486,738	
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	2,712,737	2,704,231	2,695,570	2,686,744	2,677,800	
4.	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	5,933,828	5,928,279	5,937,556	5,946,794	6,005,940	6,072,931	6,140,234	6,164,538	
6.	Average Net Investment		5,966,270	5,957,931	5,949,592	5,942,623	5,936,826	5,931,053	5,932,917	5,942,175	5,976,367	6,039,435	6,106,582	6,152,386	
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	43,626	43,694	43,945	44,409	44,903	45,240	$528,209
	b. Debt Component (Line 6 x 2.82% x 1/12)		14,021	14,001	13,982	13,965	13,952	13,938	13,942	13,964	14,044	14,193	14,350	14,458	168,810
8.	Investment Expenses														
	a. Depreciation (D)		8,339	8,339	8,339	8,342	8,348	8,353	8,375	8,414	8,506	8,661	8,826	8,944	101,786
	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	65,943	66,072	66,495	67,263	68,079	68,642	798,805
	a. Recoverable Costs Allocated to Energy		66,231	66,150	66,069	66,004	65,954	65,903	65,943	66,072	66,495	67,263	68,079	68,642	798,805
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	63,576	63,503	63,998	64,685	65,627	66,528	767,676
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	$63,576	$63,503	$63,998	$64,685	$65,627	$66,528	$767,676

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($735,849)
(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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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	$7,300	$7,300	$19,730	$172,740	$172,740	$20,190	$400,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	34,330	172,740	172,740	20,190	$400,000
	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)	$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	$8,025,382	$8,198,122	$8,370,862	$8,391,052	
3.	Less: Accumulated Depreciation	(725,979)	(746,174)	(766,369)	(786,564)	(806,759)	(826,954)	(847,149)	(867,344)	(887,539)	(907,770)	(928,216)	(949,022)	(970,029)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	7,300	14,600	0	0	0	0	
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	7,131,008	7,118,113	7,117,612	7,269,906	7,421,840	7,421,023	
6.	Average Net Investment		7,254,976	7,234,781	7,214,586	7,194,391	7,174,196	7,154,001	7,137,456	7,124,561	7,117,863	7,193,759	7,345,873	7,421,432	
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	52,483	52,388	52,339	52,897	54,015	54,571	$636,549
	b. Debt Component (Line 6 x 2.82% x 1/12)		17,049	17,002	16,954	16,907	16,859	16,812	16,773	16,743	16,727	16,905	17,263	17,440	203,434
8.	Investment Expenses														
	a. Depreciation (D)		20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,231	20,446	20,806	21,007	244,050
	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	89,451	89,326	89,297	90,248	92,084	93,018	1,084,033
	a. Recoverable Costs Allocated to Energy		90,591	90,396	90,199	90,004	89,807	89,612	89,451	89,326	89,297	90,248	92,084	93,018	1,084,033
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	86,240	85,853	85,944	86,790	88,768	90,154	1,041,779
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	$86,240	$85,853	$85,944	$86,790	$88,768	$90,154	$1,041,779

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 ($400,000), 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%, 2.5%, and 2.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	16,681	16,587	16,569	16,515	16,513	16,561	199,765
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	$16,681	$16,587	$16,569	$16,515	$16,513	$16,561	$199,765

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

DOCKET NO. 080007-EI
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 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	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	(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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	26,657	26,527	26,516	26,447	26,462	26,558	319,135
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	$26,657	$26,527	$26,516	$26,447	$26,462	$26,558	$319,135

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated 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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	22,476	22,364	22,353	22,293	22,304	22,382	269,116
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	$22,476	$22,364	$22,353	$22,293	$22,304	$22,382	$269,116

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	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)	$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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	18,051	17,957	17,943	17,891	17,895	17,955	216,132
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)		$18,350	$18,063	$18,097	$17,871	$17,887	$18,172	$18,051	$17,957	$17,943	$17,891	$17,895	$17,955	$216,132

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 Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$432,404	$74,612	$62,487	$35,386	$14,020	($77,358)	$0	$0	$0	$0	$0	$0	$541,551
	b. Clearings to Plant		0	0	0	2,737,764	14,020	(77,358)	0	0	0	0	0	0	2,674,426
	c. Retirements		0	0	0	0	0	0	0	0	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	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	
3.	Less: Accumulated Depreciation	0	0	0	0	(2,936)	(8,824)	(14,643)	(20,378)	(26,113)	(31,848)	(37,583)	(43,318)	(49,053)	
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	2,654,048	2,648,313	2,642,578	2,636,843	2,631,108	2,625,373	
6.	Average Net Investment		2,349,077	2,602,585	2,671,135	2,718,603	2,738,894	2,701,372	2,656,916	2,651,181	2,645,446	2,639,711	2,633,976	2,628,241	
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	19,537	19,495	19,452	19,410	19,368	19,326	$232,633
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,520	6,116	6,277	6,389	6,436	6,348	6,244	6,230	6,217	6,203	6,190	6,176	74,346
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	2,936	5,888	5,819	5,735	5,735	5,735	5,735	5,735	5,735	49,053
	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	31,516	31,460	31,404	31,348	31,293	31,237	356,032
	a. Recoverable Costs Allocated to Energy		22,793	25,253	25,918	29,315	32,464	32,031	31,516	31,460	31,404	31,348	31,293	31,237	356,032
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	30,385	30,237	30,225	30,147	30,166	30,275	342,157
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	$30,385	$30,237	$30,225	$30,147	$30,166	$30,275	$342,157

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,963,596) 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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated 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	$406,510	$2,519,923	$2,525,008	$2,817,969	$3,185,671	$2,553,673	$20,362,873
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	$27,255,807	$27,913,169	$28,319,679	$30,839,602	$33,364,610	$36,182,579	$39,368,250	$41,921,923	
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	27,255,807	27,913,169	28,319,679	30,839,602	33,364,610	36,182,579	39,368,250	41,921,923	
6.	Average Net Investment		22,339,984	23,404,190	24,213,079	25,353,765	26,612,321	27,584,488	28,116,424	29,579,640	32,102,106	34,773,594	37,775,414	40,645,086	
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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated 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	$2,791,177	$3,124,378	$3,593,862	$4,230,647	$4,917,729	$4,239,664	$39,295,118
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	$48,244,221	$51,368,599	$54,962,461	$59,193,108	$64,110,837	$68,350,501	
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	48,244,221	51,368,599	54,962,461	59,193,108	64,110,837	68,350,501	
6.	Average Net Investment		29,889,373	31,172,700	33,870,676	37,324,277	40,878,674	44,340,577	46,848,633	49,806,410	53,165,530	57,077,785	61,651,973	66,230,669	
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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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 and 312.44. 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% and 2.4%.
(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 Current Period Actual / Estimated Amount
January 2008 to December 2008

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		$1,544,874	$2,827,383	$1,156,124	$604,491	$471,828	$443,255	$86,496	$11,216	$79,481	$433,249	$456,481	$1,077,616	$9,192,493
	b. Clearings to Plant		0	0	0	0	0	0	78,080,176	11,216	79,481	433,249	456,481	1,077,616	$80,138,219
	c. Retirements		0	0	0	0	0	0	0	0	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)	$65,783,032	$67,327,906	$70,155,289	$71,311,412	$71,915,903	$72,387,731	$72,830,986	$78,080,175	$78,091,391	$78,170,872	$78,604,121	$79,060,602	$80,138,218	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(82,264)	(246,805)	(411,444)	(576,639)	(742,797)	(910,617)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$65,783,032	67,327,906	70,155,289	71,311,412	71,915,903	72,387,731	72,830,986	77,997,911	77,844,586	77,759,428	78,027,482	78,317,805	79,227,601	
6.	Average Net Investment		66,555,469	68,741,597	70,733,350	71,613,658	72,151,817	72,609,359	75,414,449	77,921,249	77,802,007	77,893,455	78,172,644	78,772,703	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	554,535	572,968	572,091	572,764	574,816	579,229	$3,426,403
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	177,224	183,115	182,835	183,050	183,706	185,116	1,095,046
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	82,264	164,541	164,639	165,195	166,158	167,820	910,617
	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	814,023	920,624	919,565	921,009	924,680	932,165	5,432,066
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	814,023	920,624	919,565	921,009	924,680	932,165	5,432,066
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	784,803	884,827	885,032	885,715	891,381	903,463	5,235,221
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	$784,803	$884,827	$885,032	$885,715	$891,381	$903,463	$5,235,221

Notes:

(A) Applicable depreciable base for Big Bend; account 311.43 ($3,160,938), 312.43 ($71,233,774), and 312.44 ($5,743,506)
(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 1.2%, 2.6%, and 2.4%
(D) Line 9a x Line 10
(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 Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$112,273	($49,818)	$103,703	$20,113	($236,669)	$18,261	$0	$0	$5,877	$5,877	$5,877	$5,880	($8,625)
	b. Clearings to Plant		112,273	(49,818)	103,703	20,113	(236,669)	18,261	0	0	5,877	5,877	5,877	5,880	(8,625)
	c. Retirements		0	0	0	0	0	0	0	0	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	$61,178,579	$61,178,579	$61,184,456	$61,190,333	$61,196,210	$61,202,090	
3.	Less: Accumulated Depreciation	(913,640)	(1,036,174)	(1,158,770)	(1,281,420)	(1,404,194)	(1,526,751)	(1,649,090)	(1,771,447)	(1,893,804)	(2,016,167)	(2,138,542)	(2,260,929)	(2,383,327)	
4.	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	59,407,132	59,284,775	59,168,289	59,051,791	58,935,281	58,818,763	
6.	Average Net Investment		60,291,945	60,200,608	60,104,927	60,044,123	59,813,180	59,581,528	59,468,310	59,345,953	59,226,532	59,110,040	58,993,536	58,877,022	
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	437,280	436,381	435,503	434,646	433,789	432,933	$5,257,939
	b. Debt Component (Line 6 x 2.82% x 1/12)		141,686	141,471	141,247	141,104	140,561	140,017	139,751	139,463	139,182	138,909	138,635	138,361	1,680,387
8.	Investment Expenses														
	a. Depreciation (C)		122,534	122,596	122,650	122,774	122,557	122,339	122,357	122,357	122,363	122,375	122,387	122,398	1,469,687
	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	699,388	698,201	697,048	695,930	694,811	693,692	8,408,013
	a. Recoverable Costs Allocated to Energy		707,557	706,732	705,859	705,392	702,934	700,469	699,388	698,201	697,048	695,930	694,811	693,692	8,408,013
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	674,283	671,052	670,871	669,261	669,790	672,333	8,079,877
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)		$684,793	$674,697	$676,567	$669,087	$668,708	$678,435	$674,283	$671,052	$670,871	$669,261	$669,790	$672,333	$8,079,877

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($61,202,090)
(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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. *Expenditures/Additions*		$739,281	$292,814	$256,943	$85,317	$60,668	$27,303	$45,165	$60,215	$35,100	$39,473	$15,100	$17,107	$1,674,486
	b. Clearings to Plant		0	0	0	6,418,273	60,603	$27,323	45,165	60,215	35,100	39,473	15,100	17,107	6,718,359
	c. Retirements		0	0	0	0	0	0	0	0	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	$11,552,968	$11,613,183	$11,648,283	$11,687,756	$11,702,856	$11,719,963	
3.	Less: *Accumulated Depreciation*	(71,177)	(80,763)	(90,349)	(99,935)	(115,733)	(137,801)	(159,954)	(182,176)	(204,500)	(226,915)	(249,402)	(271,941)	(294,511)	
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	11,386,974	11,424,865	11,437,550	11,454,536	11,447,097	11,441,634	
6.	Average Net Investment		10,355,330	10,861,791	11,127,084	11,285,522	11,339,581	11,361,456	11,375,503	11,405,920	11,431,208	11,446,043	11,450,817	11,444,366	
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	83,646	83,870	84,056	84,165	84,200	84,152	$991,830
	b. Debt Component (Line 6 x 2.82% x 1/12)		24,335	25,525	26,149	26,521	26,648	26,699	26,732	26,804	26,863	26,898	26,909	26,894	316,977
8.	Investment Expenses														
	a. Depreciation (C)		9,586	9,586	9,586	15,798	22,068	22,153	22,222	22,324	22,415	22,487	22,539	22,570	223,334
	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	132,600	132,998	133,334	133,550	133,648	133,616	1,532,141
	a. Recoverable Costs Allocated to Energy		110,065	114,980	117,554	125,303	132,098	132,395	132,600	132,998	133,334	133,550	133,648	133,616	1,532,141
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	127,840	127,827	128,327	128,432	128,835	129,502	1,472,481
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)		$106,524	$109,768	$112,676	$118,854	$125,666	$128,230	$127,840	$127,827	$128,327	$128,432	$128,835	$129,502	$1,472,481

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,477,493) & 312.45 ($10,242,470)
(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

DOCKET NO. 080007-EI
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 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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$1,991	$344,698	$105,208	$4,944	$5,163	$964	$0	$0	$0	$0	$0	$289,027	$751,996
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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	545,050	650,258	655,203	660,365	661,329	661,329	661,329	661,329	661,329	661,329	950,356	
5.	Net Investment (Lines 2 + 3 + 4)	$198,360	200,351	545,050	650,258	655,203	660,365	661,329	661,329	661,329	661,329	661,329	661,329	950,356	
6.	Average Net Investment		199,356	372,701	597,654	652,730	657,784	660,847	661,329	661,329	661,329	661,329	661,329	805,843	
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	4,863	4,863	4,863	4,863	4,863	5,925	$53,338
	b. Debt Component (Line 6 x 2.82% x 1/12)		468	876	1,404	1,534	1,546	1,553	1,554	1,554	1,554	1,554	1,554	1,894	17,045
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	6,417	6,417	6,417	6,417	6,417	7,819	70,383
	a. Recoverable Costs Allocated to Energy		1,934	3,617	5,799	6,334	6,383	6,412	6,417	6,417	6,417	6,417	6,417	7,819	70,383
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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	6,187	6,167	6,176	6,171	6,186	7,578	67,638
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	$6,187	$6,167	$6,176	$6,171	$6,186	$7,578	$67,638

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated 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	3,992,500	2,650,000	2,640,000	2,640,000	2,640,000	2,648,750	19,170,000
	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 - Gains	(69,802)	(63,711)	(63,283)	(61,108)	(60,570)	(58,322)	(57,933)	(48,070)	(42,204)	(36,495)	(30,683)	(24,989)	(19,442)	
3.	Total Working Capital Balance	($69,802)	(63,711)	(63,283)	(61,108)	(60,570)	(58,322)	(57,933)	(48,070)	(42,204)	(36,495)	(30,683)	(24,989)	(19,442)	
4.	Average Net Working Capital Balance		($66,757)	($63,497)	($62,196)	($60,839)	($59,446)	($58,128)	($53,002)	($45,137)	($39,350)	($33,589)	($27,836)	($22,216)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(491)	(467)	(457)	(447)	(437)	(427)	(390)	(332)	(289)	(247)	(205)	(163)	(4,352)
	b. Debt Component (Line 4 x 2.82% x 1/12)		(157)	(149)	(146)	(143)	(140)	(137)	(125)	(106)	(92)	(79)	(65)	(52)	(1,391)
6.	Total Return Component		(648)	(616)	(603)	(590)	(577)	(564)	(515)	(438)	(381)	(326)	(270)	(215)	(5,743)
7.	Expenses:														
	a. Gains		1,250	12,500	(976,697)	2,500	(1,001,697)	0	(4,001,000)	(2,654,488)	(2,644,488)	(2,644,488)	(2,644,488)	(2,653,238)	(19,204,334)
	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	14,792	58,237	58,222	56,479	58,276	54,494	56,541	438,733
8.	Net Expenses (B)		11,881	28,579	(953,364)	17,936	(985,484)	14,792	(3,942,763)	(2,596,266)	(2,588,009)	(2,586,212)	(2,589,994)	(2,596,697)	(18,765,601)
9.	Total System Recoverable Expenses (Lines 6 + 8)		11,233	27,963	(953,967)	17,346	(986,061)	14,228	(3,943,278)	(2,596,704)	(2,588,390)	(2,586,538)	(2,590,264)	(2,596,912)	(18,771,344)
	a. Recoverable Costs Allocated to Energy		11,233	27,963	(953,967)	17,346	(986,061)	14,228	(3,943,278)	(2,596,704)	(2,588,390)	(2,586,538)	(2,590,264)	(2,596,912)	(18,771,344)
	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	0.9641047	0.9611163	0.9624465	0.9616786	0.9639881	0.9692093	
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)	13,780	(3,801,733)	(2,495,735)	(2,491,187)	(2,487,418)	(2,496,984)	(2,516,951)	(18,074,636)
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)	$13,780	($3,801,733)	($2,495,735)	($2,491,187)	($2,487,418)	($2,496,984)	($2,516,951)	($18,074,636)

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 6E and 7E
(C) Line 8 is reported on Schedule 4E and 5E
(D) Line 9a x Line 10
(E) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
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DOCKET NO. 080007-EI
2009 ECRC PROJECTION FILING
EXHIBIT NO. HTB-3

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ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2009 THROUGH DECEMBER 2009

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 22
COMPANY TECO (Direct)
WITNESS Howard T. Bryant (HTB-3)
DATE 11-04-08

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2009 to December 2009

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)	$5,259,690	$334,116	$5,593,806
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	44,122,542	152,790	44,275,332
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	49,382,232	486,906	49,869,138
2. True-up for Estimated Over/(Under) Recovery for the current period January 2008 to December 2008 (Form 42-2E, Line 5 + 6 + 10)	(7,776,704)	29,611	(7,747,093)
3. Final True-up for the period January 2007 to December 2007 (Form 42-1A, Line 3)	12,598,033	(132,380)	12,465,653
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2009 to December 2009 (Line 1 - Line 2- Line 3)	44,560,903	589,675	45,150,578
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$44,592,987	$590,100	$45,183,087

Notes: Allocation to energy and demand in each period is in proportion to the respective period split of costs indicated on Lines 7 and 8 of Forms 42-5 and 42-7 of the actuals and estimates.

DOCKET NO. 080007-EI
ECRC 2009 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

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	$252,500	$251,400	$258,000	$283,400	$293,700	$295,400	$296,200	$300,900	$291,000	$291,300	$434,700	$409,500	$3,658,000		$3,658,000
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(1,009,614)	(1,018,366)	(1,009,949)	(1,010,621)	(1,007,549)	(1,011,028)	(1,007,613)	(1,007,613)	(1,011,030)	(1,007,570)	(1,012,678)	(1,009,911)	(12,123,542)		(12,123,542)
	d. Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	645,900	639,500	503,600	547,600	565,200	568,100	568,800	597,700	584,900	589,600	678,700	993,200	7,482,800		7,482,800
	e. Big Bend PM Minimization and Monitoring	55,000	50,300	55,000	32,600	24,400	23,700	24,400	24,400	23,700	44,200	41,500	55,800	455,000		455,000
	f. Big Bend NO_x Emissions Reduction	41,700	37,700	41,700	26,200	20,900	20,200	20,900	20,900	20,200	34,300	32,200	41,100	358,000		358,000
	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	12,500	12,500	12,500	12,500	0	0	0	0	0	0	0	0	50,000	50,000	
	i. Polk NO_x Reduction	5,000	5,000	7,000	8,000	6,000	6,000	6,000	6,000	6,000	6,000	8,000	6,000	75,000		75,000
	j. Bayside SCR and Ammonia	6,833	6,833	6,833	6,833	6,833	6,833	6,833	6,833	6,833	6,833	6,833	6,837	82,000		82,000
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	14,300	35,700	0	50,000		50,000
	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	24,100	21,700	24,100	7,100	0	0	0	0	0	0	0	0	77,000		77,000
	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	12,500	112,500	12,500	12,500	0	0	0	0	0	0	0	0	150,000	150,000	
	p. Arsenic Groundwater Standard Program	28,500	0	0	28,500	0	0	28,500	0	0	28,500	0	0	114,000	114,000	
	q. Big Bend 4 SCR	94,300	91,700	99,300	96,900	100,800	98,500	101,500	101,200	98,200	132,500	154,800	83,100	1,252,800		1,252,800
	r. Big Bend 3 SCR	188,200	183,700	199,300	185,400	188,400	184,300	190,100	189,100	183,900	185,100	175,500	151,900	2,204,900		2,204,900
	s. Big Bend 2 SCR	0	0	0	147,100	213,700	208,900	215,400	214,500	208,500	209,100	197,400	193,100	1,807,700		1,807,700
2.	Total of O&M Activities	391,919	394,467	209,884	384,012	412,384	400,905	451,020	453,920	412,203	534,163	759,555	1,000,726	5,805,158	$348,500	$5,456,658
3.	Recoverable Costs Allocated to Energy	303,919	269,467	184,884	330,512	412,384	400,905	422,520	453,920	412,203	505,663	759,555	1,000,726	5,456,658		
4.	Recoverable Costs Allocated to Demand	88,000	125,000	25,000	53,500	0	0	28,500	0	0	28,500	0	0	348,500		
5.	Retail Energy Jurisdictional Factor	0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253			
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)	292,267	258,953	177,432	316,861	396,408	387,570	407,372	436,100	398,206	485,944	731,948	970,629	5,259,690		
8.	Jurisdictional Demand Recoverable Costs (B)	84,368	119,840	23,968	51,292	0	0	27,324	0	0	27,324	0	0	334,116		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$376,635	$378,793	$201,400	$368,153	$396,408	$387,570	$434,696	$436,100	$398,206	$513,268	$731,948	$970,629	$5,593,806		

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

DOCKET NO. 080007-EI
ECRC 2009 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 2

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

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 Demand
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$66,346	$66,193	$66,040	$65,887	$65,733	$65,580	$65,427	$65,274	$65,121	$64,967	$64,814	$64,660	$786,042	
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	37,440	37,310	37,180	37,050	36,920	36,790	36,659	36,529	36,399	36,269	36,139	36,008	440,693	
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,796	6,781	6,767	6,752	6,738	6,723	6,708	6,693	6,678	6,664	6,649	6,635	80,584	
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,604	4,593	4,583	4,572	4,563	4,552	4,542	4,531	4,521	4,510	4,500	4,489	54,560	$ 54,560
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,573	7,555	7,538	7,521	7,504	7,487	7,470	7,452	7,435	7,418	7,401	7,384	89,738	89,738
	f.	Phillips Upgrade Tank # 1 for FDEP	497	495	493	491	490	489	487	486	485	483	482	481	5,859	5,859
	g.	Phillips Upgrade Tank # 4 for FDEP	780	778	775	773	771	768	767	764	762	760	758	755	9,211	9,211
	h.	Big Bend Unit 1 Classifier Replacement	11,759	11,725	11,689	11,654	11,619	11,584	11,549	11,514	11,478	11,444	11,408	11,373	138,796	
	i.	Big Bend Unit 2 Classifier Replacement	8,510	8,485	8,461	8,436	8,411	8,386	8,362	8,337	8,312	8,288	8,263	8,238	100,489	
	j.	Big Bend Section 114 Mercury Testing Platform	1,142	1,140	1,138	1,137	1,134	1,133	1,130	1,129	1,126	1,125	1,122	1,121	13,577	
	k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	751,770	750,628	749,491	748,232	747,204	746,098	744,713	743,343	742,007	741,272	743,852	748,617	8,957,227	
	l.	Big Bend FGD Optimization and Utilization	213,260	212,856	212,452	212,048	211,644	211,240	210,836	210,432	210,028	209,623	209,219	208,816	2,532,454	
	m.	Big Bend NO_x Emissions Reduction	67,316	65,794	65,707	65,633	65,571	65,509	65,520	65,605	65,931	66,559	67,188	67,632	793,965	
	n.	Big Bend PM Minimization and Monitoring	92,952	92,784	92,616	92,642	92,862	93,081	93,301	93,604	94,023	94,754	95,730	96,280	1,124,629	
	o.	Polk NO_x Emissions Reduction	17,045	17,001	16,959	16,915	16,873	16,830	16,787	16,744	16,701	16,658	16,616	16,572	201,701	
	p.	Big Bend Unit 4 SOFA	27,352	27,302	27,253	27,203	27,154	27,104	27,054	27,005	26,955	26,905	26,856	26,806	324,949	
	q.	Big Bend Unit 1 Pre-SCR	23,049	23,005	22,961	22,917	22,873	22,829	22,785	22,854	23,156	23,722	24,417	24,891	279,459	
	r.	Big Bend Unit 2 Pre-SCR	18,485	18,445	18,406	18,365	18,326	18,286	18,246	18,207	18,167	18,127	18,088	18,048	219,196	
	s.	Big Bend Unit 3 Pre-SCR	31,182	31,126	31,070	31,014	30,959	30,904	30,848	30,793	30,736	30,681	30,625	30,570	370,508	
	t.	Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0	
	u.	Big Bend Unit 2 SCR	0	0	0	0	911,854	1,064,158	1,076,646	1,086,295	1,096,366	1,107,280	1,118,169	1,129,178	8,589,946	
	v.	Big Bend Unit 3 SCR	936,926	935,287	933,647	932,008	930,368	928,728	927,089	925,448	923,809	922,169	920,529	918,890	11,134,898	
	w.	Big Bend Unit 4 SCR	692,538	691,351	690,163	688,975	687,788	686,600	685,412	684,225	683,037	681,849	680,662	679,474	8,232,074	
	x.	Big Bend FGD System Reliability	100,902	68,088	67,869	98,788	130,002	130,209	130,342	130,634	130,877	131,021	131,066	131,002	1,380,800	
	y.	Clean Air Mercury Rule	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	110,652	
	z.	SO_2 Emissions Allowances (B)	(185)	(177)	(169)	(161)	(153)	(144)	(136)	(127)	(117)	(108)	(100)	(92)	(1,669)	
2.		Total Investment Projects - Recoverable Costs	3,127,260	3,087,766	3,082,310	3,108,073	4,046,429	4,194,145	4,201,765	4,206,992	4,213,214	4,221,661	4,233,674	4,247,049	45,970,338	$ 159,368
3.		Recoverable Costs Allocated to Energy	3,113,806	3,074,345	3,068,921	3,094,716	4,033,101	4,180,849	4,188,499	4,193,759	4,200,011	4,208,490	4,220,533	4,233,940	45,810,970	
4.		Recoverable Costs Allocated to Demand	13,454	13,421	13,389	13,357	13,328	13,296	13,266	13,233	13,203	13,171	13,141	13,109	159,368	
5.		Retail Energy Jurisdictional Factor	0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253		
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)	2,994,427	2,954,392	2,945,231	2,966,897	3,876,861	4,041,781	4,038,331	4,029,120	4,057,394	4,044,371	4,067,131	4,106,606	44,122,542	
8.		Jurisdictional Demand Recoverable Costs (D)	12,899	12,867	12,836	12,806	12,778	12,747	12,718	12,687	12,658	12,627	12,599	12,568	152,790	
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$3,007,326	$2,967,259	$2,958,067	$2,979,703	$3,889,639	$4,054,528	$4,051,049	$4,041,807	$4,070,052	$4,056,998	$4,079,730	$4,119,174	$44,275,332	

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 2009 to December 2009

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	(3,021,777)	(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	37,845	37,729	37,613	37,497	37,381	37,265	37,149	37,032	$452,055
	b. Debt Component (Line 6 x 2.82% x 1/12)		12,243	12,206	12,169	12,132	12,095	12,058	12,021	11,984	11,947	11,909	11,872	11,835	144,471
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	65,733	65,580	65,427	65,274	65,121	64,967	64,814	64,660	786,042
	a. Recoverable Costs Allocated to Energy		66,346	66,193	66,040	65,887	65,733	65,580	65,427	65,274	65,121	64,967	64,814	64,660	786,042
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		63,802	63,610	63,378	63,166	63,187	63,399	63,081	62,711	62,910	62,433	62,458	62,715	756,850
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)		$63,802	$63,610	$63,378	$63,166	$63,187	$63,399	$63,081	$62,711	$62,910	$62,433	$62,458	$62,715	$756,850

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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	(2,534,402)	(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	17,817	17,718	17,619	17,521	17,422	17,324	17,225	17,126	$212,024
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,820	5,789	5,757	5,726	5,694	5,663	5,631	5,599	5,568	5,536	5,505	5,473	67,761
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	36,920	36,790	36,659	36,529	36,399	36,269	36,139	36,008	440,693
	a. Recoverable Costs Allocated to Energy		37,440	37,310	37,180	37,050	36,920	36,790	36,659	36,529	36,399	36,269	36,139	36,008	440,693
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		36,005	35,854	35,681	35,520	35,490	35,566	35,345	35,095	35,163	34,855	34,825	34,925	424,324
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)		$36,005	$35,854	$35,681	$35,520	$35,490	$35,566	$35,345	$35,095	$35,163	$34,855	$34,825	$34,925	$424,324

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).
(C) Applicable depreciation rates are 3.3% and 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 Projected Period 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	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	(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	3,957	3,946	3,935	3,923	3,912	3,901	3,890	3,879	$47,281
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,279	1,275	1,272	1,268	1,265	1,261	1,257	1,254	1,250	1,247	1,243	1,240	15,111
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	6,738	6,723	6,708	6,693	6,678	6,664	6,649	6,635	80,584
	a. Recoverable Costs Allocated to Energy		6,796	6,781	6,767	6,752	6,738	6,723	6,708	6,693	6,678	6,664	6,649	6,635	80,584
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		6,535	6,516	6,494	6,473	6,477	6,499	6,468	6,430	6,451	6,404	6,407	6,435	77,589
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)		$6,535	$6,516	$6,494	$6,473	$6,477	$6,499	$6,468	$6,430	$6,451	$6,404	$6,407	$6,435	$77,589

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 Projected Period 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	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	(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	2,641	2,633	2,625	2,617	2,609	2,601	2,593	2,585	$31,544
	b. Debt Component (Line 6 x 2.82% x 1/12)		854	851	849	846	844	841	839	836	834	831	829	826	10,080
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	4,563	4,552	4,542	4,531	4,521	4,510	4,500	4,489	54,560
	a. 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	4,563	4,552	4,542	4,531	4,521	4,510	4,500	4,489	54,560
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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	4,375	4,364	4,355	4,344	4,334	4,324	4,314	4,304	52,308
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,414	$4,403	$4,394	$4,383	$4,375	$4,364	$4,355	$4,344	$4,334	$4,324	$4,314	$4,304	$52,308

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	(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	4,343	4,330	4,317	4,304	4,291	4,278	4,265	4,252	$51,882
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,405	1,400	1,396	1,392	1,388	1,384	1,380	1,375	1,371	1,367	1,363	1,359	16,580
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	7,504	7,487	7,470	7,452	7,435	7,418	7,401	7,384	89,738
	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		7,573	7,555	7,538	7,521	7,504	7,487	7,470	7,452	7,435	7,418	7,401	7,384	89,738
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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	7,194	7,178	7,162	7,144	7,128	7,112	7,096	7,079	86,034
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,260	$7,243	$7,227	$7,211	$7,194	$7,178	$7,162	$7,144	$7,128	$7,112	$7,096	$7,079	$86,034

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	(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	263	262	261	260	259	258	257	256	$3,140
	b. Debt Component (Line 6 x 2.82% x 1/12)		86	85	85	84	84	84	83	83	83	82	82	82	1,003
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	490	489	487	486	485	483	482	481	5,859
	a. 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	490	489	487	486	485	483	482	481	5,859
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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	470	469	467	466	465	463	462	461	5,618
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$476	$475	$473	$471	$470	$469	$467	$466	$465	$463	$462	$461	$5,618

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	(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	413	411	410	408	406	405	403	401	$4,926
	b. Debt Component (Line 6 x 2.82% x 1/12)		134	134	133	132	132	131	131	130	130	129	129	128	1,573
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	771	768	767	764	762	760	758	755	9,211
	a. 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	771	768	767	764	762	760	758	755	9,211
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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	739	736	735	732	731	729	727	724	8,831
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$748	$746	$743	$741	$739	$736	$735	$732	$731	$729	$727	$724	$8,831

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	(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	6,062	6,035	6,009	5,982	5,955	5,929	5,902	5,875	$72,262
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,971	1,963	1,954	1,946	1,937	1,929	1,920	1,912	1,903	1,895	1,886	1,878	23,094
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	11,619	11,584	11,549	11,514	11,478	11,444	11,408	11,373	138,796
	a. Recoverable Costs Allocated to Energy		11,759	11,725	11,689	11,654	11,619	11,584	11,549	11,514	11,478	11,444	11,408	11,373	138,796
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		11,308	11,268	11,218	11,173	11,169	11,199	11,135	11,062	11,088	10,998	10,993	11,031	133,642
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)		$11,308	$11,268	$11,218	$11,173	$11,169	$11,199	$11,135	$11,062	$11,088	$10,998	$10,993	$11,031	$133,642

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 Projected Period 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	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	(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	4,446	4,427	4,409	4,390	4,371	4,353	4,334	4,315	$53,017
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,445	1,439	1,433	1,427	1,421	1,415	1,409	1,403	1,397	1,391	1,385	1,379	16,944
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	8,411	8,386	8,362	8,337	8,312	8,288	8,263	8,238	100,489
	a. Recoverable Costs Allocated to Energy		8,510	8,485	8,461	8,436	8,411	8,386	8,362	8,337	8,312	8,288	8,263	8,238	100,489
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		8,184	8,154	8,120	8,088	8,085	8,107	8,062	8,010	8,030	7,965	7,963	7,990	96,758
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)		$8,184	$8,154	$8,120	$8,088	$8,085	$8,107	$8,062	$8,010	$8,030	$7,965	$7,963	$7,990	$96,758

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 Projected Period 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	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	(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	707	706	704	703	701	700	698	697	$8,460
	b. Debt Component (Line 6 x 2.82% x 1/12)		228	227	227	227	226	226	225	225	224	224	223	223	2,705
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	1,134	1,133	1,130	1,129	1,126	1,125	1,122	1,121	13,577
	a. Recoverable Costs Allocated to Energy		1,142	1,140	1,138	1,137	1,134	1,133	1,130	1,129	1,126	1,125	1,122	1,121	13,577
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		1,098	1,096	1,092	1,090	1,090	1,095	1,089	1,085	1,088	1,081	1,081	1,087	13,072
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)		$1,098	$1,096	$1,092	$1,090	$1,090	$1,095	$1,089	$1,085	$1,088	$1,081	$1,081	$1,087	$13,072

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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

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		$69,307	$98,958	$70,377	$73,685	$51,921	$54,921	$57,121	$57,421	$64,701	$127,271	$750,151	$635,411	$2,111,245
	b. Clearings to Plant		0	0	0	0	335,963	17,887	20,087	20,387	18,187	296,035	9,487	5,687	723,720
	c. Retirements		0	0	0	0	0	0	0	0	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	$83,888,924	$83,906,811	$83,926,898	$83,947,285	$83,965,472	$84,261,507	$84,270,994	$84,276,681	
3.	Less: Accumulated Depreciation	(29,341,198)	(29,543,001)	(29,744,804)	(29,946,607)	(30,148,410)	(30,350,535)	(30,552,999)	(30,755,499)	(30,958,038)	(31,160,614)	(31,363,491)	(31,566,661)	(31,769,845)	
4.	CWIP - Non-Interest Bearing	2,533,602	2,602,909	2,701,867	2,772,244	2,845,929	2,561,887	2,598,921	2,635,955	2,672,989	2,719,503	2,550,739	3,291,403	3,921,127	
5.	Net Investment (Lines 2 + 3 + 4)	$56,745,364	56,612,868	56,510,023	56,378,597	56,250,479	56,100,275	55,952,732	55,807,353	55,662,235	55,524,360	55,448,754	55,995,735	56,427,962	
6.	Average Net Investment		56,679,116	56,561,446	56,444,310	56,314,538	56,175,377	56,026,504	55,880,043	55,734,794	55,593,298	55,486,557	55,722,245	56,211,849	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		416,771	415,906	415,044	414,090	413,067	411,972	410,895	409,827	408,787	408,002	409,735	413,335	$4,947,431
	b. Debt Component (Line 6 x 2.82% x 1/12)		133,196	132,919	132,644	132,339	132,012	131,662	131,318	130,977	130,644	130,393	130,947	132,098	1,581,149
8.	Investment Expenses														
	a. Depreciation (C)		201,803	201,803	201,803	201,803	202,125	202,464	202,500	202,539	202,576	202,877	203,170	203,184	2,428,647
	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)		751,770	750,628	749,491	748,232	747,204	746,098	744,713	743,343	742,007	741,272	743,852	748,617	8,957,227
	a. Recoverable Costs Allocated to Energy		751,770	750,628	749,491	748,232	747,204	746,098	744,713	743,343	742,007	741,272	743,852	748,617	8,957,227
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		722,948	721,340	719,283	717,328	718,258	721,280	718,013	714,161	716,811	712,364	716,815	726,103	8,624,704
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)		$722,948	$721,340	$719,283	$717,328	$718,258	$721,280	$718,013	$714,161	$716,811	$712,364	$716,815	$726,103	$8,624,704

Notes:

(A) Applicable depreciable base for Big Bend; account 312.46 ($83,318,932) and 312.45 ($957,749)
(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 2.9% and 2.3%.
(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 Projected Period 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	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	(4,032,085)	(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	128,829	128,523	128,217	127,911	127,605	127,298	126,992	126,686	$1,540,441
	b. Debt Component (Line 6 x 2.82% x 1/12)		41,564	41,466	41,368	41,270	41,173	41,075	40,977	40,879	40,781	40,683	40,585	40,488	492,309
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	211,644	211,240	210,836	210,432	210,028	209,623	209,219	208,816	2,532,454
	a. Recoverable Costs Allocated to Energy		213,260	212,856	212,452	212,048	211,644	211,240	210,836	210,432	210,028	209,623	209,219	208,816	2,532,454
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		205,084	204,551	203,889	203,290	203,445	204,214	203,277	202,171	202,896	201,448	201,615	202,536	2,438,416
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)		$205,084	$204,551	$203,889	$203,290	$203,445	$204,214	$203,277	$202,171	$202,896	$201,448	$201,615	$202,536	$2,438,416

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).
(C) Applicable depreciation rates are 1.5% and 2.3%
(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 Projected Period 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	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)	$3,486,738	$3,190,853	$3,190,853	$3,190,853	$3,193,598	$3,195,949	$3,198,753	$3,216,405	$3,234,057	$3,301,709	$3,377,361	$3,453,490	$3,486,738	
3.	Less: Accumulated Depreciation	2,677,800	2,668,820	2,659,840	2,650,860	2,641,880	2,632,900	2,623,920	2,614,940	2,605,960	2,596,980	2,587,980	2,579,000	2,570,020	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,164,538	5,859,673	5,850,693	5,841,713	5,835,478	5,828,849	5,822,673	5,831,345	5,840,017	5,898,689	5,965,341	6,032,490	6,056,758	
6.	Average Net Investment		6,012,105	5,855,183	5,846,203	5,838,595	5,832,163	5,825,761	5,827,009	5,835,681	5,869,353	5,932,015	5,998,915	6,044,624	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		44,208	43,054	42,988	42,932	42,885	42,838	42,847	42,911	43,158	43,619	44,111	44,447	$519,998
	b. Debt Component (Line 6 x 2.82% x 1/12)		14,128	13,760	13,739	13,721	13,706	13,691	13,693	13,714	13,793	13,940	14,097	14,205	166,187
8.	Investment Expenses														
	a. Depreciation (C)		8,980	8,980	8,980	8,980	8,980	8,980	8,980	8,980	8,980	9,000	8,980	8,980	107,780
	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)		67,316	65,794	65,707	65,633	65,571	65,509	65,520	65,605	65,931	66,559	67,188	67,632	793,965
	a. Recoverable Costs Allocated to Energy		67,316	65,794	65,707	65,633	65,571	65,509	65,520	65,605	65,931	66,559	67,188	67,632	793,965
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		64,735	63,227	63,059	62,922	63,031	63,330	63,171	63,029	63,692	63,963	64,746	65,598	764,503
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)		$64,735	$63,227	$63,059	$62,922	$63,031	$63,330	$63,171	$63,029	$63,692	$63,963	$64,746	$65,598	$764,503

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($735,849)
(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 3.3%, 3.1%, and 2.6%
(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 Projected Period 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	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		$3,073	$3,073	$3,073	$36,073	$36,073	$36,073	$36,073	$50,332	$56,326	$103,177	$98,230	$31,300	$492,876
	b. Clearings to Plant		3,073	3,073	3,073	36,073	36,073	36,073	36,073	50,332	56,326	103,177	98,230	31,300	492,876
	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)	$8,391,052	$8,394,125	$8,397,198	$8,400,271	$8,436,344	$8,472,417	$8,508,490	$8,544,563	$8,594,895	$8,651,221	$8,754,398	$8,852,628	$8,883,928	
3.	Less: Accumulated Depreciation	(970,029)	(991,061)	(1,012,099)	(1,033,143)	(1,054,228)	(1,075,388)	(1,096,623)	(1,117,934)	(1,139,335)	(1,160,847)	(1,182,525)	(1,204,413)	(1,226,436)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,421,023	7,403,064	7,385,099	7,367,128	7,382,116	7,397,029	7,411,867	7,426,629	7,455,560	7,490,374	7,571,873	7,648,215	7,657,492	
6.	Average Net Investment		7,412,044	7,394,082	7,376,114	7,374,622	7,389,573	7,404,448	7,419,248	7,441,095	7,472,967	7,531,124	7,610,044	7,652,854	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		54,502	54,370	54,238	54,227	54,337	54,446	54,555	54,716	54,950	55,378	55,958	56,273	$657,950
	b. Debt Component (Line 6 x 2.82% x 1/12)		17,418	17,376	17,334	17,330	17,365	17,400	17,435	17,487	17,561	17,698	17,884	17,984	210,272
8.	Investment Expenses														
	a. Depreciation (C)		21,032	21,038	21,044	21,085	21,160	21,235	21,311	21,401	21,512	21,678	21,888	22,023	256,407
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		92,952	92,784	92,616	92,642	92,862	93,081	93,301	93,604	94,023	94,754	95,730	96,280	1,124,629
	a. Recoverable Costs Allocated to Energy		92,952	92,784	92,616	92,642	92,862	93,081	93,301	93,604	94,023	94,754	95,730	96,280	1,124,629
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		89,388	89,164	88,883	88,816	89,265	89,985	89,956	89,929	90,830	91,059	92,251	93,384	1,082,910
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)		$89,388	$89,164	$88,883	$88,816	$89,265	$89,985	$89,956	$89,929	$90,830	$91,059	$92,251	$93,384	$1,082,910

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 ($892,876), 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).
(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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	(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	9,434	9,401	9,369	9,336	9,304	9,271	9,239	9,206	$112,620
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,057	3,046	3,036	3,025	3,015	3,005	2,994	2,984	2,973	2,963	2,953	2,942	35,993
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	16,873	16,830	16,787	16,744	16,701	16,658	16,616	16,572	201,701
	a. Recoverable Costs Allocated to Energy		17,045	17,001	16,959	16,915	16,873	16,830	16,787	16,744	16,701	16,658	16,616	16,572	201,701
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		16,392	16,338	16,275	16,216	16,219	16,270	16,185	16,087	16,134	16,008	16,012	16,074	194,210
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)		$16,392	$16,338	$16,275	$16,216	$16,219	$16,270	$16,185	$16,087	$16,134	$16,008	$16,012	$16,074	$194,210

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	(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	16,700	16,662	16,624	16,587	16,549	16,511	16,474	16,436	$199,717
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,385	5,373	5,361	5,349	5,337	5,325	5,313	5,301	5,289	5,277	5,265	5,253	63,828
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	27,154	27,104	27,054	27,005	26,955	26,905	26,856	26,806	324,949
	a. Recoverable Costs Allocated to Energy		27,352	27,302	27,253	27,203	27,154	27,104	27,054	27,005	26,955	26,905	26,856	26,806	324,949
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		26,303	26,237	26,155	26,079	26,102	26,202	26,084	25,945	26,040	25,856	25,880	26,000	312,883
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)		$26,303	$26,237	$26,155	$26,079	$26,102	$26,202	$26,084	$25,945	$26,040	$25,856	$25,880	$26,000	$312,883

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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	$23,226	$48,016	$77,801	$74,656	$32,106	$255,805
	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	(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	390,993	439,009	516,810	591,466	623,572	
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	1,897,249	1,940,730	2,013,996	2,084,117	2,111,688	
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	1,887,904	1,918,990	1,977,363	2,049,057	2,097,903	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,030	13,997	13,963	13,930	13,897	13,863	13,830	13,882	14,111	14,540	15,067	15,426	$170,536
	b. Debt Component (Line 6 x 2.82% x 1/12)		4,484	4,473	4,463	4,452	4,441	4,431	4,420	4,437	4,510	4,647	4,815	4,930	54,503
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	22,873	22,829	22,785	22,854	23,156	23,722	24,417	24,891	279,459
	a. Recoverable Costs Allocated to Energy		23,049	23,005	22,961	22,917	22,873	22,829	22,785	22,854	23,156	23,722	24,417	24,891	279,459
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		22,165	22,107	22,036	21,970	21,987	22,070	21,968	21,957	22,370	22,797	23,530	24,142	269,099
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)		$22,165	$22,107	$22,036	$21,970	$21,987	$22,070	$21,968	$21,957	$22,370	$22,797	$23,530	$24,142	$269,099

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 Projected Period 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	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	(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	10,790	10,760	10,730	10,700	10,670	10,640	10,610	10,580	$128,943
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,487	3,477	3,468	3,458	3,449	3,439	3,429	3,420	3,410	3,400	3,391	3,381	41,209
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	18,326	18,286	18,246	18,207	18,167	18,127	18,088	18,048	219,196
	a. Recoverable Costs Allocated to Energy		18,485	18,445	18,406	18,365	18,326	18,286	18,246	18,207	18,167	18,127	18,088	18,048	219,196
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		17,776	17,725	17,664	17,606	17,616	17,678	17,592	17,492	17,550	17,420	17,431	17,505	211,055
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)		$17,776	$17,725	$17,664	$17,606	$17,616	$17,678	$17,592	$17,492	$17,550	$17,420	$17,431	$17,505	$211,055

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 Projected Period 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	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)	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	$2,674,426	
3.	Less: Accumulated Depreciation	(49,053)	(54,788)	(60,523)	(66,258)	(71,993)	(77,728)	(83,463)	(89,198)	(94,933)	(100,668)	(106,403)	(112,138)	(117,873)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,625,373	2,619,638	2,613,903	2,608,168	2,602,433	2,596,698	2,590,963	2,585,228	2,579,493	2,573,758	2,568,023	2,562,288	2,556,553	
6.	Average Net Investment		2,622,506	2,616,771	2,611,036	2,605,301	2,599,566	2,593,831	2,588,096	2,582,361	2,576,626	2,570,891	2,565,156	2,559,421	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		19,284	19,242	19,199	19,157	19,115	19,073	19,031	18,989	18,946	18,904	18,862	18,820	$228,622
	b. Debt Component (Line 6 x 2.82% x 1/12)		6,163	6,149	6,136	6,122	6,109	6,096	6,082	6,069	6,055	6,042	6,028	6,015	73,066
8.	Investment Expenses														
	a. Depreciation (C)		5,735	5,735	5,735	5,735	5,735	5,735	5,735	5,735	5,735	5,735	5,735	5,735	68,820
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		31,182	31,126	31,070	31,014	30,959	30,904	30,848	30,793	30,736	30,681	30,625	30,570	370,508
	a. Recoverable Costs Allocated to Energy		31,182	31,126	31,070	31,014	30,959	30,904	30,848	30,793	30,736	30,681	30,625	30,570	370,508
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		29,987	29,912	29,818	29,733	29,760	29,876	29,742	29,584	29,692	29,485	29,512	29,651	356,752
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)		$29,987	$29,912	$29,818	$29,733	$29,760	$29,876	$29,742	$29,584	$29,692	$29,485	$29,512	$29,651	$356,752

Notes:

(A) Applicable depreciable base for Big Bend; account 312.43 ($1,963,596) 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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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		$3,266,698	$3,750,864	$4,112,240	$2,317,700	$1,750,922	$1,952,537	$1,954,527	$2,316,642	$2,566,349	$3,028,762	$4,557,799	$2,643,873	$34,218,913
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	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)	$41,921,923	$45,188,621	$48,939,485	$53,051,725	$55,369,425	$57,120,347	$59,072,884	$61,027,411	$63,344,053	$65,910,402	$68,939,164	$73,496,963	$76,140,836	
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)	$41,921,923	45,188,621	48,939,485	53,051,725	55,369,425	57,120,347	59,072,884	61,027,411	63,344,053	65,910,402	68,939,164	73,496,963	76,140,836	
6.	Average Net Investment		43,555,272	47,064,053	50,995,605	54,210,575	56,244,886	58,096,615	60,050,147	62,185,732	64,627,227	67,424,783	71,218,063	74,818,899	
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		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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 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 3.8%.
(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.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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		$3,511,197	$3,681,092	$1,864,529	$1,638,711	$1,423,678	$1,398,014	$997,974	$928,784	$1,070,503	$1,070,503	$1,070,503	$1,094,720	$19,750,208
	b. Clearings to Plant		0	0	0	0	86,400,079	1,398,014	997,974	928,784	1,070,503	1,070,503	1,070,503	1,094,720	$94,031,080
	c. Retirements		0	0	0	0	0	0	0	0	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)	$68,350,501	$71,861,698	$75,542,790	$77,407,319	$79,046,030	$86,400,079	$87,798,093	$88,796,067	$89,724,851	$90,795,354	$91,865,857	$92,936,360	$94,031,080	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(109,711)	(330,870)	(555,053)	(781,725)	(1,010,979)	(1,242,999)	(1,477,784)	(1,715,366)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$68,350,501	71,861,698	75,542,790	77,407,319	79,046,030	86,290,368	87,467,223	88,241,014	88,943,126	89,784,375	90,622,858	91,458,576	92,315,714	
6.	Average Net Investment		70,106,100	73,702,244	76,475,055	78,226,675	82,668,199	86,878,796	87,854,119	88,592,070	89,363,751	90,203,617	91,040,717	91,887,145	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	607,873	638,834	646,006	651,432	657,107	663,282	669,438	675,661	$5,209,633
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	194,270	204,165	206,457	208,191	210,005	211,978	213,946	215,935	1,664,947
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	109,711	221,159	224,183	226,672	229,254	232,020	234,785	237,582	1,715,366
	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	911,854	1,064,158	1,076,646	1,086,295	1,096,366	1,107,280	1,118,169	1,129,178	8,589,946
	a. Recoverable Costs Allocated to Energy		0	0	0	0	911,854	1,064,158	1,076,646	1,086,295	1,096,366	1,107,280	1,118,169	1,129,178	8,589,946
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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	876,529	1,028,761	1,038,046	1,043,649	1,059,137	1,064,099	1,077,527	1,095,218	8,282,966
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) (F)		$0	$0	$0	$0	$876,529	$1,028,761	$1,038,046	$1,043,649	$1,059,137	$1,064,099	$1,077,527	$1,095,218	$8,282,966

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 ($87,315,488) and 312.44 ($6,715,592)
(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% and 2.4%
(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.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	$80,138,218	
3.	Less: Accumulated Depreciation	(910,617)	(1,079,605)	(1,248,593)	(1,417,581)	(1,586,569)	(1,755,557)	(1,924,545)	(2,093,533)	(2,262,521)	(2,431,509)	(2,600,497)	(2,769,485)	(2,938,473)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$79,227,601	79,058,613	78,889,625	78,720,637	78,551,649	78,382,661	78,213,673	78,044,685	77,875,697	77,706,709	77,537,721	77,368,733	77,199,745	
6.	Average Net Investment		79,143,107	78,974,119	78,805,131	78,636,143	78,467,155	78,298,167	78,129,179	77,960,191	77,791,203	77,622,215	77,453,227	77,284,239	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		581,952	580,710	579,467	578,225	576,982	575,739	574,497	573,254	572,012	570,769	569,526	568,284	$6,901,417
	b. Debt Component (Line 6 x 2.82% x 1/12)		185,986	185,589	185,192	184,795	184,398	184,001	183,604	183,206	182,809	182,412	182,015	181,618	2,205,625
8.	Investment Expenses														
	a. Depreciation (C)		168,988	168,988	168,988	168,988	168,988	168,988	168,988	168,988	168,988	168,988	168,988	168,988	2,027,856
	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)		936,926	935,287	933,647	932,008	930,368	928,728	927,089	925,448	923,809	922,169	920,529	918,890	11,134,898
	a. Recoverable Costs Allocated to Energy		936,926	935,287	933,647	932,008	930,368	928,728	927,089	925,448	923,809	922,169	920,529	918,890	11,134,898
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		901,005	898,795	896,017	893,514	894,326	897,836	893,851	889,117	892,440	886,207	887,071	891,255	10,721,434
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		$901,005	$898,795	$896,017	$893,514	$894,326	$897,836	$893,851	$889,117	$892,440	$886,207	$887,071	$891,255	$10,721,434

Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($3,160,938), 312.43 ($71,233,774), and 312.44 ($5,743,506)
(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 1.2%, 2.6%, and 2.4%
(D) Line 9a x Line 10

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	$61,202,090	
3.	Less: Accumulated Depreciation	(2,383,327)	(2,505,731)	(2,628,135)	(2,750,539)	(2,872,943)	(2,995,347)	(3,117,751)	(3,240,155)	(3,362,559)	(3,484,963)	(3,607,367)	(3,729,771)	(3,852,175)	
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)	$58,818,763	58,696,359	58,573,955	58,451,551	58,329,147	58,206,743	58,084,339	57,961,935	57,839,531	57,717,127	57,594,723	57,472,319	57,349,915	
6.	Average Net Investment		58,757,561	58,635,157	58,512,753	58,390,349	58,267,945	58,145,541	58,023,137	57,900,733	57,778,329	57,655,925	57,533,521	57,411,117	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		432,054	431,154	430,254	429,354	428,454	427,554	426,654	425,754	424,854	423,954	423,054	422,154	$5,125,248
	b. Debt Component (Line 6 x 2.82% x 1/12)		138,080	137,793	137,505	137,217	136,930	136,642	136,354	136,067	135,779	135,491	135,204	134,916	1,637,978
8.	Investment Expenses														
	a. Depreciation (C)		122,404	122,404	122,404	122,404	122,404	122,404	122,404	122,404	122,404	122,404	122,404	122,404	1,468,848
	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)		692,538	691,351	690,163	688,975	687,788	686,600	685,412	684,225	683,037	681,849	680,662	679,474	8,232,074
	a. Recoverable Costs Allocated to Energy		692,538	691,351	690,163	688,975	687,788	686,600	685,412	684,225	683,037	681,849	680,662	679,474	8,232,074
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		665,987	664,376	662,347	660,519	661,144	663,762	660,838	657,364	659,844	655,259	655,922	659,039	7,926,401
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)		$665,987	$664,376	$662,347	$660,519	$661,144	$663,762	$660,838	$657,364	$659,844	$655,259	$655,922	$659,039	$7,926,401

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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	$11,719,963	$5,001,604	$5,001,604	$5,001,604	$11,419,877	$11,480,480	$11,507,803	$11,552,968	$11,613,183	$11,648,283	$11,687,756	$11,702,856	$11,719,963	
3.	Less: Accumulated Depreciation	(294,511)	(317,097)	(339,683)	(362,269)	(384,855)	(407,441)	(430,027)	(452,613)	(475,199)	(497,785)	(520,371)	(542,957)	(565,543)	
4.	CWIP - Non-Interest Bearing	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	16,182	
5.	Net Investment (Lines 2 + 3 + 4)	$11,441,634	4,700,689	4,678,103	4,655,517	11,051,204	11,089,221	11,093,958	11,116,537	11,154,166	11,166,680	11,183,567	11,176,081	11,170,602	
6.	Average Net Investment		8,071,161	4,689,396	4,666,810	7,853,360	11,070,212	11,091,590	11,105,248	11,135,352	11,160,423	11,175,124	11,179,824	11,173,342	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		59,349	34,482	34,316	57,747	81,401	81,558	81,659	81,880	82,064	82,173	82,207	82,159	$840,995
	b. Debt Component (Line 6 x 2.82% x 1/12)		18,967	11,020	10,967	18,455	26,015	26,065	26,097	26,168	26,227	26,262	26,273	26,257	268,773
8.	Investment Expenses														
	a. Depreciation (C)		22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	22,586	271,032
	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)		100,902	68,088	67,869	98,788	130,002	130,209	130,342	130,634	130,877	131,021	131,066	131,002	1,380,800
	a. Recoverable Costs Allocated to Energy		100,902	68,088	67,869	98,788	130,002	130,209	130,342	130,634	130,877	131,021	131,066	131,002	1,380,800
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		97,034	65,431	65,134	94,708	124,966	125,878	125,669	125,506	126,433	125,912	126,302	127,062	1,330,035
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)		$97,034	$65,431	$65,134	$94,708	$124,966	$125,878	$125,669	$125,506	$126,433	$125,912	$126,302	$127,062	$1,330,035

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($1,477,493) and 312.45 ($10,242,470)
(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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	$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	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	
5.	Net Investment (Lines 2 + 3 + 4)	$950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	
6.	Average Net Investment		950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	950,356	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,988	6,988	6,988	6,988	6,988	6,988	6,988	6,988	6,988	6,988	6,988	6,988	$83,856
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,233	2,233	2,233	2,233	2,233	2,233	2,233	2,233	2,233	2,233	2,233	2,233	26,796
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)		9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	110,652
	a. Recoverable Costs Allocated to Energy		9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	9,221	110,652
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		8,867	8,861	8,849	8,840	8,864	8,914	8,890	8,859	8,908	8,861	8,886	8,944	106,543
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)		$8,867	$8,861	$8,849	$8,840	$8,864	$8,914	$8,890	$8,859	$8,908	$8,861	$8,886	$8,944	$106,543

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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 to December 2009

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January 09	Projected February 09	Projected March 09	Projected April 09	Projected May 09	Projected June 09	Projected July 09	Projected August 09	Projected September 09	Projected October 09	Projected November 09	Projected 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		1,099,890	1,099,890	1,100,220	1,099,890	1,099,890	1,100,220	1,099,890	1,099,890	1,100,220	1,099,890	1,099,890	1,100,220	$13,200,000
	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 - Gains	(19,442)	(18,618)	(17,842)	(17,013)	(16,182)	(15,323)	(14,415)	(13,492)	(12,569)	(11,659)	(10,779)	(9,891)	(9,100)	
3.	Total Working Capital Balance	($19,442)	($18,618)	($17,842)	($17,013)	($16,182)	($15,323)	($14,415)	($13,492)	($12,569)	($11,659)	($10,779)	($9,891)	($9,100)	
4.	Average Net Working Capital Balance		($19,030)	($18,230)	($17,428)	($16,598)	($15,753)	($14,869)	($13,954)	($13,031)	($12,114)	($11,219)	($10,335)	($9,496)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($140)	($134)	($128)	($122)	($116)	($109)	($103)	($96)	($89)	($82)	($76)	($70)	($1,265)
	b. Debt Component (Line 6 x 2.82% x 1/12)		($45)	($43)	($41)	($39)	($37)	($35)	($33)	($31)	($28)	($26)	($24)	($22)	($404)
6.	Total Return Component (B)		(185)	(177)	(169)	(161)	(153)	(144)	(136)	(127)	(117)	(108)	(100)	(92)	($1,669)
7.	Expenses:														
	a. Gains		(1,100,457)	(1,100,457)	(1,100,787)	(1,100,457)	(1,100,457)	(1,100,787)	(1,100,457)	(1,100,457)	(1,100,787)	(1,100,457)	(1,100,457)	(1,100,787)	(13,206,804)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		90,843	82,091	90,838	89,836	92,908	89,759	92,844	92,844	89,757	92,887	87,779	90,876	1,083,262
8.	Net Expenses (C)		(1,009,614)	(1,018,366)	(1,009,949)	(1,010,621)	(1,007,549)	(1,011,028)	(1,007,613)	(1,007,613)	(1,011,030)	(1,007,570)	(1,012,678)	(1,009,911)	(12,123,542)
9.	Total System Recoverable Expenses (Lines 6 + 7)		($1,009,799)	($1,018,543)	($1,010,118)	($1,010,782)	($1,007,702)	($1,011,172)	($1,007,749)	($1,007,740)	($1,011,147)	($1,007,678)	($1,012,778)	($1,010,003)	($12,125,211)
	a. Recoverable Costs Allocated to Energy		(1,009,799)	(1,018,543)	(1,010,118)	(1,010,782)	(1,007,702)	(1,011,172)	(1,007,749)	(1,007,740)	(1,011,147)	(1,007,678)	(1,012,778)	(1,010,003)	(12,125,211)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9616613	0.9609826	0.9596958	0.9586978	0.9612606	0.9667369	0.9641476	0.9607418	0.9660436	0.9610028	0.9636533	0.9699253	
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)		(971,085)	(978,802)	(969,406)	(969,034)	(968,664)	(977,537)	(971,619)	(968,178)	(976,812)	(968,381)	(975,967)	(979,627)	(11,675,113)
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($971,085)	($978,802)	($969,406)	($969,034)	($968,664)	($977,537)	($971,619)	($968,178)	($976,812)	($968,381)	($975,967)	($979,627)	($11,675,113)

Notes:
(A) 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)
(B) Line 6 id reported on Scgedule 3P.
(C) Line 8 is reported on Schedule 2P
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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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 2008 through December 2008, is $808,109 compared to the original projection of $808,109, representing no variance.

The actual/estimated O&M expense for the period January 2008 through December 2008 is $3,287,684 compared to the original projection of $3,688,900 representing a variance of 10.9%. 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 2009 through December 2009, is expected to be $786,042.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $3,658,000.

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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 2008 through December 2008 is $459,431 compared to the original projection of $459,431 representing no variance.

The actual/estimated O&M expense for this project for the period January 2008 through December 2008 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 2009 through December 2009 is projected to be $440,693.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $0.

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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 2008 through December 2008 is $82,704 compared to the original projection of $82,704 representing no variance.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $80,584.

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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 2008 through December 2008 is $143,853 compared to the original projection of $143,853 representing no variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $138,796.

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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 2008 through December 2008 is $104,046 compared to the original projection of $104,046 representing no variance.

Progress Summary: The project was placed in-service May 1998.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $100,489.

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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 2008 through December 2008 is $8,919,694 compared to the original projection of $8,915,093 representing an insignificant variance.

The actual/estimated O&M expense for the period January 2008 through December 2008 is $6,337,155 as compared to the original estimate of $7,243,000 resulting in a variance of 12.5%. 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 2009 through December 2009 is expected to be $8,957,227.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $7,482,800.

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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 2008 through December 2008, is $13,858 compared to the original projection of $13,858 representing no 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 2009 through December 2009 is expected to be $13,577.

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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 2008 through December 2008 is $2,590,639 compared to the original projection of $2,590,639 representing no variance.

Progress Summary: The project was placed in-service in January 2002.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is expected to be $2,532,454.

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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 2008 through December 2008 is $1,084,033 as compared to the original projection of $1,127,247 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2008 through December 2008 is $438,402 as compared to the original projection of $450,000 resulting in a variance of 2.6%. This variance is due to the decrease in inspection work during the Unit 3 outage as well as the overall improved precipitator performance.

Progress Summary: This project was placed in-service July 2005.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is expected to be $1,124,629.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $455,000.

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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 2008 through December 2008 is $798,805 as compared to the original projection of $872,714 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2008 through December 2008 is $512,435 as compared to the original projection of $350,000 resulting in a variance of 46.4%. This variance is due to unanticipated inspections on boiler tubes and burner modifications.

Progress Summary: The project was placed in-service January 2008.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is expected to be $793,965.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $358,000.

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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 2008 through December 2008 is $56,068 compared to the original projection of $56,068 representing no variance.

Progress Summary: The project was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $54,560.

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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 2008 through December 2008 is $92,212 compared to the original projection of $92,212 representing no variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $89,738.

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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 2008 through December 2008, is $6,064 compared to the original projection of $6,064 representing no variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $5,859.

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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 2008 through December 2008 is $9,528 compared to the original projection of $9,528 representing no variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $9,211.

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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 2008 through December 2008 is ($5,743) compared to the original projection of ($9,165) representing a 37.3% variance. The variance is due to the sale of SO_2 allowances originally projected to occur in 2008 but transpired throughout 2007.

The actual/estimated O&M for the period January 2008 through December 2008 is ($18,765,601) compared to the original projection of ($29,413,430) representing a variance of 36.2%. The significant variance is due to the sale of SO_2 allowances originally projected to occur in 2008 that actually transpired in 2007.

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 2009 through December 2009 is projected to be ($1,669).

Estimated O&M costs for the period January 2009 through December 2009 are projected to be ($12,123,542).

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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 2008 through December 2008 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 2009 through December 2009 are projected to be $34,500.

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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 2008 through December 2008 is $76,005 compared to the original projection of $50,000, which represents a variance of 52.0%. The variance is due to the need for additional data collection than what was originally planned.

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 2009.

Projections: Estimated O&M costs for the period January 2009 through December 2009 are projected to be $50,000.

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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 2008 through December 2008 is $207,879 as compared to the original projection of $207,879 representing no variance.

The actual/estimated O&M for the period January 2008 through December 2008 is $46,667 compared to the original projection of $65,000, which represents a variance of 28.2 %. The variance is due to a unit outage during the second quarter of 2008.

Progress Summary: The project was placed in-service January 2005.

Project Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $201,701.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $75,000.

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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 2008 through December 2008 is $108,068 compared to the original projection of $70,000 resulting in a variance of 54.4%. 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 2009 through December 2009 are projected to be $82,000.

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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 2008 through December 2008 is $332,096 compared to the original projection of $332,096 representing no variance.

The actual/estimated O&M for the period January 2008 through December 2008 is $32,976 compared to the original projection of $50,000, which represents a variance of 34.0%. This variance is due to less maintenance activity than anticipated.

Progress Summary: The project was placed in-service November 2004.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $324,949.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $50,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2009 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 2008 through December 2008 is $280,044 compared to the original projection of $279,624 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2008 through December 2008 is $30,000 compared to the original projection of $75,000, which represents a variance of 60.0%. 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 2009 through December 2009 is projected to be $279,459.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $77,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2009 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 2008 through December 2008 is $224,909 compared to the original projection of $224,909 resulting in no variance.

The actual/estimated O&M for the period January 2008 through December 2008 is $11,188 compared to the original projection of $75,000, which represents a variance of 85.1%. 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 2009 through December 2009 is projected to be $219,196.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $77,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2009 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 2008 through December 2008 is $356,032 compared to the original projection of $437,512 resulting in a variance of 18.6%. This variance is due to the deferment of activities and associated costs to 2009 after the completion of the outage scheduled for the end of 2008.

The actual/estimated O&M for the period January 2008 through December 2008 is $2 compared to the original projection of $0 resulting in an insignificant 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 2009 through December 2009 is projected to be $370,508.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2008 through December 2008 is $124,395 compared to the original projection of $150,000, which represents a variance of 17.1%. 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 2009 through December 2009 are projected to be $150,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2009 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 2009 through December 2009 is projected to be $0.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2009 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 2009.

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 April 2009, 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 2009 through December 2009 is projected to be $8,589,946.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $1,807,700.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2009 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 2009.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2008 through December 2008 is $5,432,066 compared to the original projection of $8,778,536, which represents variance of 38.1%. This variance is due to turbine rotor repair that caused the delay in commercial operation.

The actual/estimated O&M for the period January 2008 through December 2008 is $1,200,000 compared to the original projection of $1,606,900 representing a variance of 25.3%. 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 2009 through December 2009 is projected to be $11,134,898.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $2,204,900.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2009 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 2009.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2008 through December 2008 is $8,408,013 compared to the original projection of $6,125,701, which represents variance 0f 37.1%. This variance is due to an inadvertent error found in the formula for the amount of average return on investment for the months of January through May 2008 of the 2008 Projection filing.

The actual/estimated O&M for the period January 2008 through December 2008 is $1,331,036 compared to the original projection of $1,610,000 representing a variance of 17.3%. The variance is due to the decreased usage of ammonia.

Progress Summary: This project went in to service in May 2008.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $8,232,074.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $1,252,800.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2008 through December 2008 is $98,651 compared to the original projection of $57,000, which represents a variance of 73.1%. The FDEP requested to extend the data collection period, therefore requiring additional testing.

Progress Summary: In Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2008, the Commission granted Tampa Electric cost recovery approval for prudent costs associated with this project.

Projections: Estimated O&M costs for the period January 2009 through December 2009 are projected to be $114,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2008 through December 2008 is $1,532,141 compared to the original projection of $1,549,199, resulting in an insignificant variance.

Progress Summary: In Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2008, the Commission granted cost recovery approval for prudent costs associated with this project.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $1,380,800.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2009 through December 2009
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 2008 through December 2008 is $70,383 compared to the original projection of $119,317, which represents a variance of 41.0%. The variance is due to the decrease in the scope of the project as a result of the Circuit Court decision to vacate the rule.

Progress Summary: A petition was filed on August 30, 2008 seeking Commission approval of cost recovery through the ECRC for the new CAMR program.

Projections: Estimated depreciation plus return for the period January 2009 through December 2009 is projected to be $110,652.

Estimated O&M costs for the period January 2009 through December 2009 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2009 to December 2009

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 Secondary (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 & 1/13 Allocation Factor (%)
RS, RST	54.27%	9,068,656	9,068,656	1,908	1.08536	1.054823	9,565,824	2,071	45.53%	54.82%	54.11%
GS, GST, TS	57.68%	1,090,649	1,090,649	216	1.08536	1.054823	1,150,441	234	5.48%	6.19%	6.14%
GSD, GSDT	74.86%	5,629,887	5,628,510	859	1.08430	1.054259	5,935,356	931	28.25%	24.64%	24.92%
GSLD, GSLDT, SBF	85.29%	2,583,910	2,571,851	346	1.07227	1.044076	2,697,798	371	12.84%	9.82%	10.05%
IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3	99.42%	1,393,108	1,371,631	160	1.03968	1.021235	1,422,691	166	6.77%	4.39%	4.57%
SL/OL	515.88%	225,470	225,470	5	1.08536	1.054823	237,831	5	1.13%	0.13%	0.21%
TOTAL *		19,991,680	19,956,767	3,494			21,009,941	3,778	100.00%	100.00%	100.00%

Notes: (1) Average 12 CP load factor based on 2009 proposed load research data
(2) Projected MWh sales for the period January 2009 to December 2009
(3) Projected effective sales at secondary for the period January 2009 to December 2009
(4) Calculated: (Column 2) / (8,760 hours x Column 1)
(5) Based on 2009 proposed load research data
(6) Based on 2009 proposed load research data
(7) Column 2 x Column 6
(8) Column 4 x Column 5
(9) Column 6 / Total Column 6
(10) Column 7 / Total Column 7
(11) Column 8 x 1/13 + Column 9 x 12/13

* Totals on this schedule may not foot due to rounding

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EXHIBIT NO. HTB-3
DOCUMENT NO. 6

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2009 to December 2009

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 1/13 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, RST	45.53%	54.11%	20,303,187	319,303	20,622,490	9,068,656	9,068,656	**0.227**
GS, GST, TS	5.48%	6.14%	2,443,696	36,232	2,479,928	1,090,649	1,090,649	**0.227**
GSD, GSDT	28.25%	24.92%	12,597,519	147,053	12,744,572	5,629,887	5,628,510	
Secondary								**0.226**
Primary								**0.224**
Transmission								**0.222**
GSLD, GSLDT, SBF	12.84%	10.05%	5,725,740	59,305	5,785,045	2,583,910	2,571,851	
Secondary								**0.225**
Primary								**0.222**
Transmission								**0.220**
IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3	6.77%	4.57%	3,018,945	26,968	3,045,913	1,393,108	1,371,631	
Secondary								**0.222**
Primary								**0.219**
Transmission								**0.217**
SL/OL	1.13%	0.21%	503,901	1,239	505,140	225,470	225,470	**0.224**
TOTAL *	100.00%	100.00%	44,592,987	590,100	45,183,087	19,991,680	19,956,767	**0.226**

Notes:
(1) From Form 42-6P, Column 8
(2) From Form 42-6P, Column 10
(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

* Totals on this schedule may not foot due to rounding

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
May 2009 to December 2009
Projected

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	54.27%	6,488,202	6,488,202	1,908	1.08536	1.054823	6,843,905	2,071	45.53%	54.82%	52.50%
GS, TS	57.68%	739,631	739,631	208	1.08536	1.054823	780,180	225	5.23%	5.96%	5.78%
GSD, SBF	80.38%	6,707,437	6,684,030	1,372	1.07602	1.046728	7,020,862	1,476	48.11%	39.09%	41.35%
LS1	515.88%	150,739	150,739	5	1.08536	1.054823	159,003	5	1.13%	0.13%	0.38%
TOTAL *		14,086,009	14,062,602	3,493			21,824,812	3,778	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 May 2009 to December 2009
(3) Effective sales at secondary level
(4) Based on 12 months average CP at meter
(5) Based on 2009 load research data
(6) Average 12 CP load factor based on 2009 load research data
(7) Projected MWh sales for the period May 2009 to December 2009
(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

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DOCUMENT NO. 8

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
May 2009 to December 2009
Projected

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	45.530%	52.50%	14,413,074	93,611	14,506,685	6,488,202	6,488,202	**0.223**
GS, TS	5.230%	5.78%	1,655,620	10,306	1,665,926	739,631	739,631	**0.225**
GSD, SBF	48.110%	41.35%	15,229,805	73,730	15,303,535	6,707,437	6,684,030	
Secondary								**0.229**
Primary								**0.227**
Transmission								**0.224**
LS1	1.130%	0.38%	357,715	678	358,393	150,739	150,739	**0.238**
TOTAL *	100.00%	100.00%	31,656,214	178,307	31,834,521	14,086,009	14,062,602	**0.226**

* Totals on this schedule may not foot due to rounding

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Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

August 21, 2007

Winston K. Borkowski
Hopping, Green & Sams
P.O. Box 6526
Tallahassee, Florida 32314

Re: Request for Clarification of Department Policy after EPA Suspension of 316(b) Phase II Existing Facilities Rule

Dear Mr. Borkowski,

This letter is in response to your June 4, 2007 letter and is intended to clarify the Florida Department of Environmental Protection's (Department) future plans and implementation of Section 316(b) of the Clean Water Act (CWA 316(b)) regarding Phase II "Existing Facilities." You specifically had an interest in the need to complete a Comprehensive Demonstration Study (CDS).

As you know, CWA 316(b) requires "that the location, design, construction and capacity of the cooling water intake structures reflect the best technology available [BTA] for minimizing adverse environmental impacts."

In light of the ruling in Riverkeeper Inc. v. EPA, 475 F. 3d 83 (2d Cir. Jan 25 2007) and EPA's subsequent suspension of majority of their rule, the Department plans to revise its rules regarding Phase II "Existing Facilities." In the near future, the Department will begin rulemaking that will amend its current rules that adopt by reference the suspended federal rules. The Department's amended rules will be applied either at permit renewal (for permits that do not incorporate the suspended EPA rules) or in a permit reopening (for permits that currently incorporate the suspended EPA rules).

Despite the Court's ruling and EPA's suspension of the rule, the requirements of CWA 316(b) still exist and need to be addressed. Thus, all facilities subject to CWA 316(b) must meet BTA. The Department will implement the requirements of CWA 316(b) on a Best Professional Judgment basis. Historically, this has been conducted in a three step-process:

- Evaluation of site specific entrainment and impingement impacts
- Identification and evaluation of measures to minimize adverse impacts
- Design and implementation of specific measures, if needed, to minimize any identified adverse impacts

The Department believes that some form of Comprehensive Demonstration Study (CDS), especially the biological studies used to determine baseline conditions, and evaluation of control technologies and operational strategies is an integral part of this three-step process. All of the Florida power plants with once through cooling water systems have provided a proposal for information collection, and nine plants are expected to complete their CDS by January 2008, with another eleven plants expected to complete their CDS throughout the remainder of 2008. Very few plants have not started or are at the very early stages of this information collection.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 23
COMPANY Gulf Power Co. (Direct)
WITNESS James O. Vick (JOV-1)
DATE 11-04-08

EPA has provided guidance to the states on the implementation of 316(b) requirements in light of the rule suspension. We are currently reviewing the EPA guidance and plan to develop Florida specific guidance in the near future to coincide with our rulemaking to repeal the suspended EPA rule.

If you have any further questions, please feel free to contact me.

Sincerely,

Phil Coram, P.E.
Deputy Director
Division of Water Resource Management

cc: Allen Hubbard, P.E., DEP - Tallahassee
Jim Giattina, Director, EPA Region 4, Water Management Division
Roosevelt Childress, Chief, EPA Region 4, NPDES & Biosolids Permit Section

Exhibit to the Testimony of James O. Vick

Exhibit (JOV-2)_____

Enclosed Documentation	Page
Plant Crist Consumptive Use Permit	1
NWFWMD correspondence to Gulf Power dated July 3, 2008	8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 24
COMPANY Gulf Power Co. (Direct)
WITNESS James O. Vick (JOV-2)
DATE 11-04-08

Northwest Florida Water Management District
N.W.F.W.M.D

Douglas E. Barr
Executive Director

Northwest Florida Water Management

Division of Resource Regulation
152 Water Management Drive, Havana, Florida 32333-4711
(U.S. Highway 90, 10 miles west of Tallahassee)
(850) 539-5999 • (Suncom) 793-5999 • (Fax) 539-2777

January 28, 2005

Gulf Power, Inc.
Crist Electric Generating Plant
One Energy Place
Pensacola, FL 32520-0328

NOTICE OF AGENCY ACTION
Individual Water Use Permit No. 19850074
Consumptive Use Permit Application No. I06475

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 January 27, 2005. 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.

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 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
Division of Resource Regulation

Enclosure
cc: Richard M. Markey

JOYCE ESTES, Chair, Eastpoint
L. E. MCMULLIAN, Vice Chair, Sneads
STEPHANIE H. BLOYD, Secretary/Treasurer, Panama City Beach
LOIS BENSON, Pensacola
WAYNE BODIE, DeFuniak Springs
PAUL BRADSHAW, Havana
HULAN CARTER, Chipley
SHARON T. GASKIN, Wewahitchka
RICHARD PETERMANN, Fort Walton Beach

NORTHWEST FLORIDA WATER MANAGEMENT DISTRICT
INDIVIDUAL WATER USE PERMIT
(NWFWMD Form No. A2-E)

Permit granted to:

Gulf Power Company
Crist Electrical Generating Plant
One Energy Place

Pensacola, Florida 32520-0328
(Legal Name and Address)

Permit No.: 19850074 Modification/Renewal

Date Permit Granted: January 27, 2005

Permit Expires On: February 1, 2010

Source Classification: Sand-and-Gravel Aquifer
Governor's Bayou/
Escambia River

Use Classification: Public Supply
Power Generation

County: Escambia Area: C

Location: Section 25 1/4 Section

Application No.: I06475

Township 1 North Range 30 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.

5. This Permit authorizes the Permittee to make a combined average annual withdrawal of **257,500,000*** gallons of water per day, a maximum combined withdrawal of **305,400,000**** gallons during a single day, and a combined monthly withdrawal of **9,366,700,000***** 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
CEGP #2 (AAA6423)	Sec. 25, T1N, R30W		720,000 Abandoned
CEGP #3 (AAA6421)	Sec. 25, T1N, R30W		1,080,000
CEGP #4 (AAA6418)	Sec. 25, T1N, R30W		1,080,000
CEGP #5 (AAA6420)	Sec. 25, T1N, R30W		1,080,000
CEGP #6 (AAA6419)	Sec. 25, T1N, R30W		1,080,000
CEGP #7	Sec. 25, T1N, R30W		1,080,000
CEGP 1A	Sec. 25, T1N, R30W		24,480,000
CEGP 1B	Sec. 25, T1N, R30W		24,480,000
CEGP 2A	Sec. 25, T1N, R30W		24,480,000
CEGP 2B	Sec. 25, T1N, R30W		24,480,000
CEGP 3A	Sec. 25, T1N, R30W		28,800,000
CEGP 3B	Sec. 25, T1N, R30W		28,800,000
CEGP 4A	Sec. 25, T1N, R30W		56,160,000
CEGP 4B	Sec. 25, T1N, R30W		56,160,000
CEGP 5A	Sec. 25, T1N, R30W		56,160,000
CEGP 5B	Sec. 25, T1N, R30W		56,160,000
CEGP 6A/7A	Sec. 25, T1N, R30W		17,568,000
CEGP 6B/7B	Sec. 25, T1N, R30W		17,568,000
CEGP 7C/7C	Sec. 25, T1N, R30W		17,568,000
* 2,500,000 Ground Water – 255,000,000 Surface Water ** 5,400,000 Ground Water – 300,000,000 Surface Water *** 88,360,000 Ground Water – 9,278,300,000 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.

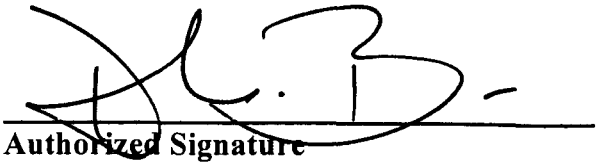
14. Nothing in this Permit should be construed to limit the authority of the Northwest Florida Water Management District to declare water shortages and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate and implement a plan during periods of water shortage pursuant to Section 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
Crist Electrical Generating Plant

Individual Water Use Permit No. 19850074
Individual Water Use Application No. I06475

1. The Permittee shall include the Individual Water Use Permit number and each well's Florida Unique Identification Number (e.g., AAA###) when submitting reports or otherwise corresponding with the District.

2. The Permittee shall maintain, in working order, in-line totaling flow meters on the well head of each production well.

3. The Permittee shall record the data required on 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 and surface water). The ground and surface water withdrawals shall also be provided as a combined total. 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 report for the year 2005 is due by January 31, 2006.

4. The Permittee, by January 31 of each year, shall report the following information:

   a. Water quality sample results from withdrawal well AAA6421 (CEPG #3) collected during the first two weeks of each month and analyzed for sodium, chloride, sulfate, bicarbonate, carbonate, calcium, magnesium, potassium, specific conductance, total dissolved solids and pH. Prior to sampling, the Permittee shall purge three to five well volumes from the well, and shall report with the test results, the purging duration, volume and rate used.

   b. Static water level data for each production well during the first two weeks of January, April, July, and October. The water level data shall be referenced to mean sea level.

   The Permittee, if preferred, may submit the reports electronically by e-mailing the data to compliance@nwfwmd.state.fl.us.

   The Permittee shall immediately initiate monthly collection, analysis, and reporting of ground-water quality samples and ground-water levels from all withdrawal wells identified in this permit, should drawdowns or water quality exceed a level of concern, as determined by the District. In this event, the Permittee shall, within 30 days, submit a written plan to the District identifying the specific actions it will implement to address the issue(s) of concern including monthly recording of the required data.

5. The Permittee shall continue to return at least 95% of the surface water withdrawn from Governor's Bayou/Escambia River. The Permittee shall submit a statement to this effect by January 31 of each year. The first statement is due by January 31, 2006.

6. The Permittee shall implement measures to increase water conservation and efficiency at the facility. The Permittee, by January 31 of each year, shall submit to the District a report detailing the actions taken, and the progress during the previous year, in achieving the stated goal. The first submittal is due by January 31, 2006.

7. The Permittee shall mitigate interference to existing users that is attributable to the withdrawal amounts authorized herein, should it occur. The Permittee shall report the occurrence of any such interference to the District and shall identify the mitigation action undertaken to address the interference.

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 E. Barr
Executive Director

July 3, 2008

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328

RE: Individual Water Use Permit No. 19850074
Specific Condition No. 6

Dear Mr. Markey:

The District understands that Gulf Power is working to obtain reuse water from Emerald Coast Utilities Authority and that this is part of Gulf Power's water conservation effort in accordance with Specific Condition No. 6 of the Individual Water Use Permit. Obtaining 17-20 million gallons of reuse water per day for cooling and for emissions reduction would result in a significant benefit to the water resources of the area by reducing demand for ground water and surface water. 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

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007- December 2007

Line		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2007- December 2007 (Schedule 2A, Line 5 + 6 + 9)	(647,455)
2	Estimated/Actual True-Up Amount approved for the period January 2007- December 2007 (FPSC Order No. PSC-07-0922-FOF-EI)	(2,117,926)
3	Final True-Up Amount to be refunded/(recovered) in the projection period January 2009 - December 2009 (Lines 1 - 2)	1,470,471

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 25
COMPANY Gulf Power Co. (Direct)
WITNESS Rhonda J. Martin (RJM-1)
DATE 11-04-08

Docket No. 080007-EI
ECRC 2007 Final True-up
Exhibit RJM-1, Page 1 of 35

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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)	3,365,831	3,065,975	2,996,329	2,988,676	3,728,111	4,237,777	4,564,048	5,003,501	3,971,018	3,614,292	2,958,591	3,247,526	43,741,674
2	True-Up Provision (Order No. PSC-06-0972-FOF-EI)	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,809	4,533,763
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	3,743,645	3,443,789	3,374,143	3,366,490	4,105,925	4,615,591	4,941,862	5,381,315	4,348,832	3,992,106	3,336,405	3,625,335	48,275,437
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5A, Line 9)	909,280	1,898,401	1,389,700	999,142	1,306,224	1,589,432	1,672,102	1,476,123	1,312,233	1,376,431	1,142,019	1,267,269	16,338,356
	b Capital Investment Projects (Schedule 7A, Line 9)	2,487,325	2,543,601	2,542,041	2,554,732	2,574,053	2,730,204	2,877,415	2,872,126	2,864,191	2,862,057	2,844,800	2,853,785	32,606,330
	c **Total Jurisdictional ECRC Costs**	3,396,605	4,442,002	3,931,741	3,553,874	3,880,277	4,319,636	4,549,517	4,348,249	4,176,424	4,238,488	3,986,819	4,121,054	48,944,686
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	347,040	(998,213)	(557,598)	(187,384)	225,648	295,955	392,345	1,033,066	172,408	(246,382)	(650,414)	(495,719)	(669,249)
6	Interest Provision (Schedule 3A, Line 10)	29,736	26,327	20,955	17,758	16,264	15,855	15,744	17,841	18,609	15,426	11,753	8,268	214,536
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2006	5,133,105	5,132,067	3,589,625	2,675,168	2,127,728	1,991,826	1,925,822	1,956,097	2,629,190	2,442,393	1,833,623	817,148	5,133,105
	b Final True-Up from January 2005 - December 2005 (Order No. PSC-06-0972-FOF-EI)	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043
8	True-Up Collected/(Refunded) (see Line 2)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,809)	(4,533,763)
9	Adjustments		(192,742)											(192,742)
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8 + 9)	6,791,110	5,248,668	4,334,211	3,786,771	3,650,869	3,584,865	3,615,140	4,288,233	4,101,436	3,492,666	2,476,191	1,610,930	1,610,930

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Docket No. 080007-EI
ECRC 2007 Final True-up
Exhibit RJM-1, Page 2 of 35

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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)	6,792,148	6,791,110	5,248,668	4,334,211	3,786,771	3,650,869	3,584,865	3,615,140	4,288,233	4,101,436	3,492,666	2,476,191	
2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8 + 9)	6,761,374	5,222,341	4,313,256	3,769,013	3,634,605	3,569,010	3,599,396	4,270,392	4,082,827	3,477,240	2,464,438	1,602,662	
3 Total of Beginning & Ending True-up (Lines 1 + 2)	13,553,522	12,013,451	9,561,924	8,103,224	7,421,376	7,219,879	7,184,261	7,885,532	8,371,060	7,578,676	5,957,103	4,078,853	
4 Average True-Up Amount (Line 3 x 1/2)	6,776,761	6,006,726	4,780,962	4,051,612	3,710,688	3,609,940	3,592,131	3,942,766	4,185,530	3,789,338	2,978,552	2,039,427	
5 Interest Rate (First Day of Reporting Business Month)	0.052700	0.052600	0.052600	0.052600	0.052600	0.052600	0.052800	0.052400	0.056200	0.050500	0.047200	0.047500	
6 Interest Rate (First Day of Subsequent Business Month)	0.052600	0.052600	0.052600	0.052600	0.052600	0.052800	0.052400	0.056200	0.050500	0.047200	0.047500	0.049800	
7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.105300	0.105200	0.105200	0.105200	0.105200	0.105400	0.105200	0.108600	0.106700	0.097700	0.094700	0.097300	
8 Average Interest Rate (Line 7 x 1/2)	0.052650	0.052600	0.052600	0.052600	0.052600	0.052700	0.052600	0.054300	0.053350	0.048850	0.047350	0.048650	
9 Monthly Average Interest Rate (Line 8 x 1/12)	0.004388	0.004383	0.004383	0.004383	0.004383	0.004392	0.004383	0.004525	0.004446	0.004071	0.003946	0.004054	
10 Interest Provision for the Month (Line 4 x Line 9)	29,736	26,327	20,955	17,758	16,264	15,855	15,744	17,841	18,609	15,426	11,753	8,268	214,536

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Docket No. 080007-EI
ECRC 2007 Final True-up
Exhibit RJM-1, Page 3 of 35

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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	803,824	803,824	0	0.0 %
.3	Title V	69,415	80,320	(10,905)	(13.6) %
.4	Asbestos Fees	2,835	2,500	335	13.4 %
.5	Emission Monitoring	431,605	480,665	(49,060)	(10.2) %
.6	General Water Quality	387,210	344,221	42,989	12.5 %
.7	Groundwater Contamination Investigation	1,322,652	1,352,251	(29,599)	(2.2) %
.8	State NPDES Administration	69,250	34,750	34,500	99.3 %
.9	Lead and Copper Rule	18,585	19,553	(968)	(5.0) %
.10	Env Auditing/Assessment	10,827	10,462	365	3.5 %
.11	General Solid & Hazardous Waste	681,915	552,933	128,982	23.3 %
.12	Above Ground Storage Tanks	59,855	101,050	(41,195)	(40.8) %
.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	191,511	211,531	(20,020)	(9.5) %
.17	Gulf Coast Ozone Study	0	0	0	0.0 %
.18	SPCC Substation Project	0	0	0	0.0 %
.19	FDEP NOX Reduction Agreement	2,785,702	2,970,940	(185,238)	(6.2) %
.20	SO2 Allowances	10,069,739	10,884,512	(814,773)	(7.5) %
2	Total O & M Activities	16,904,925	17,849,512	(944,587)	(5.3) %
3	Recoverable Costs Allocated to Energy	14,351,796	15,431,792	(1,079,996)	(7.0) %
4	Recoverable Costs Allocated to Demand	2,553,129	2,417,720	135,409	5.6 %

Notes:

Column (1) contains the End of Period Totals from Schedule 5A
Column (2) contains the approved Estimated/Actual amounts in accordance with FPSC Order No. PSC-07-0922-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Docket No. 080007-EI
ECRC 2007 Final True-up
Exhibit RJM-1, Page 4 of 35

Schedule 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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	-	679,450	-	-	-	-	-	-	-	124,374	-	-	803,824	0	803,824
	.3 Title V	5,189	6,687	5,028	4,791	6,857	5,049	5,182	6,159	4,517	8,749	5,841	5,366	69,415	0	69,415
	.4 Asbestos Fees	-	1,500	1,000	-	-	-	335	-	-	-	-	-	2,835	2,835	0
	.5 Emission Monitoring	27,555	33,940	34,654	27,982	11,475	60,996	47,631	64,072	28,352	23,184	38,225	33,539	431,605	0	431,605
	.6 General Water Quality	(154)	5,489	34,117	26,588	(8,045)	43,513	21,640	43,855	26,630	114,299	55,634	23,644	387,210	387,210	0
	.7 Groundwater Contamination Investigation	8,100	55,782	60,973	36,155	53,269	270,253	350,865	52,988	140,274	96,776	87,084	110,133	1,322,652	1,322,652	0
	.8 State NPDES Administration	34,500	-	-	-	-	250	-	-	-	-	-	34,500	69,250	69,250	0
	.9 Lead and Copper Rule	3,386	-	-	3,558	-	4,209	(34)	-	3,583	3,583	300	-	18,585	18,585	0
	.10 Env Auditing/Assessment	-	-	14	-	8,761	1,087	19	41	-	51	-	855	10,827	10,827	0
	.11 General Solid & Hazardous Waste	172,717	25,677	44,095	49,856	86,091	66,031	46,683	41,704	69,699	6,744	36,110	36,508	681,915	681,915	0
	.12 Above Ground Storage Tanks	-	-	16,623	175	29,434	(8,816)	2,151	7,593	50	9,659	283	2,703	59,855	59,855	0
	.13 Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	14,066	16,005	14,426	14,026	21,746	9,262	21,948	23,878	14,941	5,211	27,707	8,295	191,511	0	191,511
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.19 FDEP NOX Reduction Agreement	230,029	225,634	217,368	156,712	254,786	228,898	284,257	254,050	235,660	197,362	250,694	250,252	2,785,702	0	2,785,702
	.20 SO2 Allowances (A)	446,393	918,490	1,009,941	713,763	885,676	962,600	948,261	1,030,508	833,968	831,831	680,541	807,767	10,069,739	0	10,069,739
2	Total of O & M Activities	941,781	1,968,654	1,438,239	1,033,606	1,350,050	1,643,332	1,728,938	1,524,848	1,357,674	1,421,823	1,182,419	1,313,562	16,904,925	2,553,129	14,351,796
3	Recoverable Costs Allocated to Energy	723,232	1,880,206	1,281,417	917,274	1,180,540	1,266,805	1,307,279	1,378,667	1,117,438	1,190,711	1,003,008	1,105,219	14,351,796		
4	Recoverable Costs Allocated to Demand	218,549	88,448	156,822	116,332	169,510	376,526	421,659	146,181	240,236	231,112	179,411	208,343	2,553,129		
5	Retail Energy Jurisdictional Factor	0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568			
6	Retail Demand Jurisdictional Factor	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872			
7	Jurisdictional Energy Recoverable Costs (B)	698,055	1,812,917	1,238,134	886,709	1,142,395	1,225,524	1,264,574	1,334,841	1,080,048	1,153,064	968,621	1,065,908	13,870,790		
8	Jurisdictional Demand Recoverable Costs (C)	211,225	85,484	151,566	112,433	163,829	363,908	407,528	141,282	232,185	223,367	173,398	201,361	2,467,566		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	909,280	1,898,401	1,389,700	999,142	1,306,224	1,589,432	1,672,102	1,476,123	1,312,233	1,376,431	1,142,019	1,267,269	16,338,356		

Notes:
(A) Page 28 of Schedule 8A, Line 8
(B) Line 3 x Line 5 x line loss multiplier
(C) Line 4 x Line 6

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Schedule 6A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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	49,907	49,907	0	0.0	%
.2	For Project: Crist 5, 6 & 7 Precipitator Projects	2,011,027	2,011,027	0	0.0	%
.3	For Project: Crist 7 Flue Gas Conditioning	168,969	168,969	0	0.0	%
.4	For Project: Low NOx Burners, Crist 6 & 7	2,085,306	2,085,306	0	0.0	%
.5	For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel	767,072	770,919	(3,847)	(0.5)	%
.6	For Project: Sub. Contam. Mobile Groundwater Treat. Sys.	106,908	106,908	0	0.0	%
.7	For Project: Raw Water Well Flowmeters - Plants Crist & Smith	28,631	28,631	0	0.0	%
.8	For Project: Crist Cooling Tower Cell	71,549	73,956	(2,407)	(3.3)	%
.9	Crist 1-5 Dechlorination	29,478	29,478	0	0.0	%
.10	Crist Diesel Fuel Oil Remediation	7,371	7,371	0	0.0	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	9,815	9,815	0	0.0	%
.12	Crist IWW Sampling System	5,718	5,718	0	0.0	%
.13	For Project: Sodium Injection System	51,259	51,259	0	0.0	%
.14	For Project: Smith Stormwater Collection System	266,972	266,972	0	0.0	%
.15	Smith Waste Water Treatment Facility	36,814	36,814	0	0.0	%
.16	For Project: Daniel Ash Management Project	2,209,523	2,210,005	(482)	(0.0)	%
.17	For Project: Smith Water Conservation	17,008	17,008	0	0.0	%
.18	For Project: Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	For Project: Crist FDEP Agreement for Ozone Attainment	18,565,027	18,561,912	3,115	0.0	%
.20	Crist Stormwater Collection System	131,175	131,175	0	0.0	%
.21	Crist Common FTIR Monitor	8,352	8,352	0	0.0	%
.22	Precipitator Upgrades for CAM Compliance	1,986,579	2,096,283	(109,704)	(5.2)	%
.23	Plant Groundwater Investigation	0	0	0	0.0	%
.24	Crist Water Conservation	13,423	13,423	0	0.0	%
.25	Crist Condenser Tubes	821,670	821,670	0	0.0	%
.26	CAIR/CAMR/CAVR Compliance	2,243,319	2,273,939	(30,620)	(1.3)	%
.27	General Water Quality	1,673	1,673	0	0.0	%
.28	SO2 Allowances	2,041,094	2,019,015	22,079	36.0	%
2	Total Investment Projects - Recoverable Costs	33,735,639	33,857,505	(121,866)	(0.4)	%
3	Recoverable Costs Allocated to Energy	30,268,513	30,387,713	(119,200)	(0.4)	%
4	Recoverable Costs Allocated to Demand	3,467,126	3,469,792	(2,666)	(0.1)	%

Notes:
Column (1) contains the End of Period Totals from Schedule 7A
Column (2) contains the approved Estimated/Actual amounts in accordance with FPSC Order No. PSC-07-0922-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Schedule 7A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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	4,295	4,270	4,245	4,220	4,195	4,172	4,147	4,122	4,097	4,073	4,048	4,023	49,907	0	49,907
	.2 For Project: Crist 5, 6 & 7 Precipitator Projects	170,187	169,714	169,240	168,768	168,295	167,822	167,349	166,876	166,404	165,930	165,457	164,985	2,011,027	0	2,011,027
	.3 For Project: Crist 7 Flue Gas Conditioning	14,091	14,090	14,087	14,086	14,083	14,082	14,080	14,078	14,076	14,074	14,072	14,070	168,969	0	168,969
	.4 For Project: Low NOx Burners, Crist 6 & 7	175,092	174,799	174,571	174,343	174,114	173,885	173,656	173,427	173,198	172,970	172,740	172,511	2,085,306	0	2,085,306
	.5 For Project: 'CEMS - Plants Crist, Scholz, Smith, & D	64,022	63,910	63,798	63,685	63,582	63,419	63,249	63,494	64,256	64,666	64,553	64,438	767,072	0	767,072
	.6 For Project: Sub. Contam. Mobile Groundwater Treat	9,004	8,988	8,970	8,954	8,935	8,918	8,901	8,883	8,866	8,848	8,831	8,810	106,908	98,684	8,224
	.7 For Project: Raw Water Well Flowmeters - Plants Cri	2,417	2,411	2,405	2,400	2,395	2,389	2,383	2,377	2,371	2,367	2,361	2,355	28,631	26,429	2,202
	.8 For Project: Crist Cooling Tower Cell	6,893	6,870	6,846	6,821	6,934	7,230	6,086	4,771	4,701	4,633	4,792	4,972	71,549	66,046	5,503
	.9 Crist 1-5 Dechlorination	2,499	2,491	2,484	2,476	2,468	2,460	2,453	2,445	2,437	2,429	2,422	2,414	29,478	27,211	2,267
	.10 Crist Diesel Fuel Oil Remediation	624	622	621	618	617	615	613	612	610	608	606	605	7,371	6,803	568
	.11 Crist Bulk Tanker Unload Sec Contain Struc	832	829	827	824	822	819	817	814	812	809	806	804	9,815	9,060	755
	.12 Crist IWW Sampling System	485	484	481	480	479	477	476	475	472	471	470	468	5,718	5,278	440
	.13 For Project: Sodium Injection System	4,322	4,313	4,304	4,295	4,285	4,276	4,267	4,258	4,249	4,239	4,230	4,221	51,259	0	51,259
	.14 For Project: Smith Stormwater Collection System	22,548	22,494	22,439	22,386	22,330	22,274	22,220	22,165	22,111	22,056	22,002	21,947	266,972	246,437	20,535
	.15 Smith Waste Water Treatment Facility	3,087	3,083	3,081	3,076	3,074	3,070	3,065	3,063	3,059	3,055	3,053	3,048	36,814	33,980	2,834
	.16 For Project: Daniel Ash Management Project	186,656	186,244	185,860	185,479	184,913	184,406	183,917	183,386	182,905	182,407	181,917	181,433	2,209,523	2,039,560	169,963
	.17 For Project: Smith Water Conservation	1,431	1,429	1,427	1,423	1,422	1,418	1,416	1,414	1,412	1,407	1,406	1,403	17,008	15,698	1,310
	.18 For Project: Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 For Project: Crist FDEP Agreement for Ozone Attain	1,556,128	1,552,420	1,548,787	1,554,972	1,557,779	1,551,192	1,548,070	1,544,543	1,540,954	1,538,656	1,536,404	1,535,122	18,565,027	0	18,565,027
	.20 Crist Stormwater Collection System	10,424	10,961	11,192	11,124	11,015	10,992	10,969	10,946	10,923	10,900	10,876	10,853	131,175	121,084	10,091
	.21 Crist Common FTIR Monitor	705	702	702	700	697	697	696	693	692	691	689	688	8,352	0	8,352
	.22 For Project: Precipitator Upgrades for CAM Compliai	114,010	118,163	125,120	140,055	162,137	175,387	178,019	185,155	194,122	194,754	192,615	207,042	1,986,579	0	1,986,579
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	1,132	1,130	1,127	1,124	1,122	1,119	1,118	1,115	1,113	1,110	1,108	1,105	13,423	12,391	1,032
	.25 Crist Condenser Tubes	69,279	69,132	68,986	68,839	68,692	68,546	68,399	68,253	68,106	67,960	67,812	67,666	821,670	758,465	63,205
	.26 CAIR/CAMR/CAVR Compliance	315	827	1,378	1,845	5,858	173,710	338,646	339,125	339,578	342,968	345,450	353,619	2,243,319	0	2,243,319
	.27 General Water Quality	0	0	0	0	112	223	223	223	223	223	223	223	1,673	0	1,673
	.28 SO2 Allowances	156,165	216,944	207,847	199,858	190,009	178,848	169,603	160,223	151,614	143,757	136,623	129,603	2,041,094	0	2,041,094
2	Total Investment Projects - Recoverable Costs	2,576,643	2,637,320	2,630,825	2,642,851	2,660,364	2,822,446	2,974,838	2,966,936	2,963,361	2,956,061	2,945,566	2,958,428	33,735,639	3,467,126	30,268,513
3	Recoverable Costs Allocated to Energy	2,283,738	2,344,548	2,338,446	2,351,137	2,369,393	2,531,923	2,686,069	2,680,120	2,677,303	2,670,775	2,660,832	2,674,229	30,268,513		
4	Recoverable Costs Allocated to Demand	292,905	292,772	292,379	291,714	290,971	290,523	288,769	286,816	286,058	285,286	284,734	284,199	3,467,126		
5	Retail Energy Jurisdictional Factor	0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568			
6	Retail Demand Jurisdictional Factor	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872			
7	Jurisdictional Energy Recoverable Costs (B)	2,204,236	2,260,641	2,259,460	2,272,794	2,292,833	2,449,417	2,598,323	2,594,922	2,587,720	2,586,332	2,569,608	2,579,110	29,255,396		
8	Jurisdictional Demand Recoverable Costs (C)	283,089	282,960	282,581	281,938	281,220	280,787	279,092	277,204	276,471	275,725	275,192	274,675	3,350,934		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	2,487,325	2,543,601	2,542,041	2,554,732	2,574,053	2,730,204	2,877,415	2,872,126	2,864,191	2,862,057	2,844,800	2,853,785	32,606,330		

Notes:

(A) Pages 1-27 of Schedule 8A, Line 9, Page 28 of Schedule 8A, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

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ECRC 2007 Final True-up
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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)	(41,740)	(44,363)	(46,986)	(49,608)	(52,231)	(54,853)	(57,476)	(60,099)	(62,722)	(65,345)	(67,968)	(70,591)	(73,214)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	178,554	175,931	173,308	170,686	168,063	165,441	162,818	160,195	157,572	154,949	152,326	149,703	147,080	
6	Average Net Investment		177,243	174,620	171,997	169,375	166,752	164,130	161,507	158,884	156,261	153,638	151,015	148,392	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,302	1,283	1,264	1,244	1,225	1,206	1,187	1,167	1,148	1,129	1,110	1,090	14,355
	b Debt Component (Line 6 x Debt Component x 1/12)		370	364	359	353	348	343	337	332	326	321	315	310	4,078
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	2,622	2,623	2,622	2,623	2,623	2,623	2,623	2,623	2,623	2,623	31,474
	c Dismantlement		0	0	0	0	0	0	0	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)		4,295	4,270	4,245	4,220	4,195	4,172	4,147	4,122	4,097	4,073	4,048	4,023	49,907
	a Recoverable Costs Allocated to Energy		4,295	4,270	4,245	4,220	4,195	4,172	4,147	4,122	4,097	4,073	4,048	4,023	49,907
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		4,145	4,117	4,102	4,079	4,059	4,036	4,012	3,991	3,960	3,944	3,909	3,880	48,234
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)		4,145	4,117	4,102	4,079	4,059	4,036	4,012	3,991	3,960	3,944	3,909	3,880	48,234

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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 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)	(1,781,062)	(1,831,194)	(1,881,326)	(1,931,458)	(1,981,590)	(2,031,722)	(2,081,854)	(2,131,986)	(2,182,118)	(2,232,250)	(2,282,382)	(2,332,514)	(2,382,646)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	12,750,816	12,700,684	12,650,552	12,600,420	12,550,288	12,500,156	12,450,024	12,399,892	12,349,760	12,299,628	12,249,496	12,199,364	12,149,232	
6	Average Net Investment		12,725,750	12,675,618	12,625,486	12,575,354	12,525,222	12,475,090	12,424,958	12,374,826	12,324,694	12,274,562	12,224,430	12,174,298	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		93,496	93,128	92,759	92,391	92,023	91,654	91,286	90,918	90,550	90,181	89,813	89,445	1,097,644
	b Debt Component (Line 6 x Debt Component x 1/12)		26,559	26,454	26,349	26,245	26,140	26,036	25,931	25,826	25,722	25,617	25,512	25,408	311,799
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)		170,187	169,714	169,240	168,768	168,295	167,822	167,349	166,876	166,404	165,930	165,457	164,985	2,011,027
	a Recoverable Costs Allocated to Energy		170,187	169,714	169,240	168,768	168,295	167,822	167,349	166,876	166,404	165,930	165,457	164,985	2,011,027
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		164,262	163,640	163,524	163,145	162,857	162,353	161,882	161,571	160,836	160,684	159,784	159,117	1,943,655
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)		164,262	163,640	163,524	163,145	162,857	162,353	161,882	161,571	160,836	160,684	159,784	159,117	1,943,655

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 2007 - December 2007

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)	1,472,159	1,471,955	1,471,751	1,471,547	1,471,343	1,471,139	1,470,935	1,470,731	1,470,527	1,470,323	1,470,119	1,469,915	1,469,711	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,472,159	1,471,955	1,471,751	1,471,547	1,471,343	1,471,139	1,470,935	1,470,731	1,470,527	1,470,323	1,470,119	1,469,915	1,469,711	
6	Average Net Investment		1,472,057	1,471,853	1,471,649	1,471,445	1,471,241	1,471,037	1,470,833	1,470,629	1,470,425	1,470,221	1,470,017	1,469,813	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,815	10,814	10,812	10,811	10,809	10,808	10,806	10,805	10,803	10,802	10,800	10,799	129,684
	b Debt Component (Line 6 x Debt Component x 1/12)		3,072	3,072	3,071	3,071	3,070	3,070	3,070	3,069	3,069	3,068	3,068	3,067	36,837
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)		14,091	14,090	14,087	14,086	14,083	14,082	14,080	14,078	14,076	14,074	14,072	14,070	168,969
	a Recoverable Costs Allocated to Energy		14,091	14,090	14,087	14,086	14,083	14,082	14,080	14,078	14,076	14,074	14,072	14,070	168,969
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		13,600	13,586	13,611	13,617	13,628	13,623	13,620	13,630	13,605	13,629	13,590	13,570	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)		13,600	13,586	13,611	13,617	13,628	13,623	13,620	13,630	13,605	13,629	13,590	13,570	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 2007 - December 2007

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		589	208	(2)	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		589	208	(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 Cost of Removal		(14,559)	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)	9,097,128	9,097,717	9,097,925	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)	6,909,843	6,871,022	6,846,759	6,822,495	6,798,231	6,773,967	6,749,703	6,725,439	6,701,175	6,676,911	6,652,647	6,628,383	6,604,119	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	16,006,971	15,968,739	15,944,684	15,920,418	15,896,154	15,871,890	15,847,626	15,823,362	15,799,098	15,774,834	15,750,570	15,726,306	15,702,042	
6	Average Net Investment		15,987,855	15,956,712	15,932,551	15,908,286	15,884,022	15,859,758	15,835,494	15,811,230	15,786,966	15,762,702	15,738,438	15,714,174	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		117,463	117,234	117,056	116,878	116,700	116,522	116,343	116,165	115,987	115,809	115,630	115,452	1,397,239
	b Debt Component (Line 6 x Debt Component x 1/12)		33,367	33,302	33,251	33,201	33,150	33,099	33,049	32,998	32,947	32,897	32,846	32,795	396,902
8	Investment Expenses														
	a Depreciation (E)		24,262	24,263	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	291,165
	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)		175,092	174,799	174,571	174,343	174,114	173,885	173,656	173,427	173,198	172,970	172,740	172,511	2,085,306
	a Recoverable Costs Allocated to Energy		175,092	174,799	174,571	174,343	174,114	173,885	173,656	173,427	173,198	172,970	172,740	172,511	2,085,306
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		168,997	168,543	168,674	168,534	168,488	168,219	167,983	167,914	167,403	167,501	166,818	166,375	2,015,449
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)		168,997	168,543	168,674	168,534	168,488	168,219	167,983	167,914	167,403	167,501	166,818	166,375	2,015,449

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 Final True-Up Amount
January 2007 - December 2007

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, 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	0	1,848	66	935	74,591	110,273	312	(753)	(72)	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	47,553	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)	4,346,031	4,346,031	4,346,031	4,346,031	4,346,031	4,346,031	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	
3	Less: Accumulated Depreciation (C)	1,044,072	1,032,178	1,020,284	1,008,390	996,496	984,602	1,020,322	1,008,551	996,780	985,009	973,238	961,467	949,696	
4	CWIP - Non Interest Bearing	0	0	0	0	0	1,848	1,914	2,849	77,440	187,713	188,025	187,272	187,201	
5	Net Investment (Lines 2 + 3 + 4)	5,390,103	5,378,209	5,366,315	5,354,421	5,342,527	5,332,481	5,320,714	5,309,878	5,372,698	5,471,200	5,459,741	5,447,217	5,435,375	
6	Average Net Investment		5,384,156	5,372,262	5,360,368	5,348,474	5,337,504	5,326,598	5,315,296	5,341,288	5,421,949	5,465,471	5,453,479	5,441,296	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		39,557	39,470	39,383	39,295	39,215	39,135	39,051	39,242	39,835	40,155	40,067	39,977	474,382
	b Debt Component (Line 6 x Debt Component x 1/12)		11,237	11,212	11,187	11,162	11,139	11,117	11,093	11,147	11,316	11,406	11,381	11,356	134,753
8	Investment Expenses														
	a Depreciation (E)		11,762	11,762	11,762	11,762	11,762	11,701	11,639	11,639	11,639	11,639	11,639	11,639	140,345
	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		1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	16,008
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		64,022	63,910	63,798	63,685	63,582	63,419	63,249	63,494	64,256	64,666	64,553	64,438	767,072
	a Recoverable Costs Allocated to Energy		64,022	63,910	63,798	63,685	63,582	63,419	63,249	63,494	64,256	64,666	64,553	64,438	767,072
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		61,793	61,623	61,643	61,563	61,528	61,352	61,183	61,476	62,106	62,621	62,340	62,146	741,374
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)		61,793	61,623	61,643	61,563	61,528	61,352	61,183	61,476	62,106	62,621	62,340	62,146	741,374

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 $634,465. Ending Balances: Crist, $2,232,602; Scholz $790,065; Smith $688,899; Daniel $586,912.
(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 2007 - December 2007

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)	(157,270)	(159,106)	(160,941)	(162,777)	(164,614)	(166,449)	(168,285)	(170,121)	(171,957)	(173,793)	(175,629)	(177,465)	(179,301)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	760,754	758,918	757,083	755,247	753,410	751,575	749,739	747,903	746,067	744,231	742,395	740,559	738,723	
6	Average Net Investment		759,837	758,001	756,166	754,329	752,493	750,658	748,822	746,986	745,150	743,314	741,478	739,642	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,583	5,569	5,556	5,542	5,529	5,515	5,502	5,488	5,475	5,461	5,448	5,434	66,102
	b Debt Component (Line 6 x Debt Component x 1/12)		1,586	1,582	1,578	1,574	1,570	1,567	1,563	1,559	1,555	1,551	1,547	1,544	18,776
8	Investment Expenses														
	a Depreciation (E)		1,836	1,835	1,836	1,837	1,835	1,836	1,836	1,836	1,836	1,836	1,836	1,836	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)		9,004	8,988	8,970	8,954	8,935	8,918	8,901	8,883	8,866	8,848	8,831	8,810	106,909
	a Recoverable Costs Allocated to Energy		692	691	690	689	688	686	684	683	683	681	679	678	8,224
	b Recoverable Costs Allocated to Demand		8,312	8,297	8,280	8,265	8,247	8,232	8,217	8,200	8,183	8,167	8,152	8,132	98,684
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		668	666	667	666	666	664	662	661	660	659	656	654	7,949
13	Retail Demand-Related Recoverable Costs (I)		8,033	8,019	8,003	7,988	7,971	7,956	7,942	7,925	7,909	7,893	7,879	7,859	95,377
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,701	8,685	8,670	8,654	8,637	8,620	8,604	8,586	8,569	8,552	8,535	8,513	103,326

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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E. 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	
3	Less: Accumulated Depreciation (C)	(49,444)	(50,038)	(50,632)	(51,226)	(51,820)	(52,414)	(53,008)	(53,602)	(54,196)	(54,790)	(55,384)	(55,978)	(56,572)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	193,499	192,905	192,311	191,717	191,123	190,529	189,935	189,341	188,747	188,153	187,559	186,965	186,371	
6	Average Net Investment		193,202	192,608	192,014	191,420	190,826	190,232	189,638	189,044	188,450	187,856	187,262	186,668	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,419	1,415	1,411	1,406	1,402	1,398	1,393	1,389	1,385	1,380	1,376	1,371	16,745
	b Debt Component (Line 6 x Debt Component x 1/12)		403	402	401	399	398	397	396	395	393	392	391	390	4,757
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	594	594	594	594	594	594	594	594	7,129
	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)		2,417	2,411	2,405	2,400	2,395	2,389	2,383	2,377	2,371	2,367	2,361	2,355	28,631
	a Recoverable Costs Allocated to Energy		186	185	185	185	184	184	184	183	182	182	181	181	2,202
	b Recoverable Costs Allocated to Demand		2,231	2,226	2,220	2,215	2,211	2,205	2,199	2,194	2,189	2,185	2,180	2,174	26,429
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		180	178	179	179	178	178	178	177	176	176	175	175	2,129
13	Retail Demand-Related Recoverable Costs (I)		2,156	2,151	2,146	2,141	2,137	2,131	2,125	2,120	2,116	2,112	2,107	2,101	25,543
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,336	2,329	2,325	2,320	2,315	2,309	2,303	2,297	2,292	2,288	2,282	2,276	27,672

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,920 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 Final True-Up Amount
January 2007 - December 2007

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	906,659	0	0	0	0	0	
	d Cost of Removal		0	0	0	103	40,517	39,496	(16,136)	0	(14,288)	0	17,042	4,552	
	e Salvage		0	0	0	0	11,552	631	4,859	76	0	(76)	(16,915)	(127)	
2	Plant-in-Service/Depreciation Base (B)	906,659	906,659	906,659	906,659	906,659	906,659	906,659	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	(448,111)	(450,691)	(453,271)	(455,851)	(458,328)	(431,943)	(395,658)	488,635	488,397	473,946	473,860	507,655	512,173	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	458,548	455,968	453,388	450,808	448,331	474,716	511,001	488,635	488,397	473,946	473,860	507,655	512,173	
6	Average Net Investment		457,258	454,678	452,098	449,570	461,524	492,859	499,818	488,516	481,171	473,903	490,758	509,914	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,359	3,341	3,322	3,303	3,391	3,621	3,672	3,589	3,535	3,482	3,606	3,746	41,967
	b Debt Component (Line 6 x Debt Component x 1/12)		954	949	944	938	963	1,029	1,043	1,020	1,004	989	1,024	1,064	11,921
8	Investment Expenses														
	a Depreciation (E)		2,418	2,418	2,418	2,418	2,418	2,418	1,209	0	0	0	0	0	15,717
	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)		6,893	6,870	6,846	6,821	6,934	7,230	6,086	4,771	4,701	4,633	4,792	4,972	71,549
	a Recoverable Costs Allocated to Energy		530	528	527	525	533	556	468	367	362	356	369	382	5,503
	b Recoverable Costs Allocated to Demand		6,363	6,342	6,319	6,296	6,401	6,674	5,618	4,404	4,339	4,277	4,423	4,590	66,046
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		512	509	509	508	516	538	453	355	350	345	356	368	5,319
13	Retail Demand-Related Recoverable Costs (I)		6,150	6,129	6,107	6,085	6,186	6,450	5,430	4,256	4,194	4,134	4,275	4,436	63,832
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,662	6,638	6,616	6,593	6,702	6,988	5,883	4,611	4,544	4,479	4,631	4,804	69,151

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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(in Dollars)

Line	Description	Beginning of Period Amoun	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)	(126,316)	(127,130)	(127,944)	(128,759)	(129,573)	(130,387)	(131,201)	(132,015)	(132,829)	(133,643)	(134,457)	(135,271)	(136,085)	
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)	179,007	178,193	177,379	176,564	175,750	174,936	174,122	173,308	172,494	171,680	170,866	170,052	169,238	
6	Average Net Investment		178,600	177,786	176,972	176,157	175,343	174,529	173,715	172,901	172,087	171,273	170,459	169,645	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,312	1,306	1,300	1,294	1,288	1,282	1,276	1,270	1,264	1,258	1,252	1,246	15,348
	b Debt Component (Line 6 x Debt Component x 1/12)		373	371	369	368	366	364	363	361	359	357	356	354	4,361
8	Investment Expenses														
	a Depreciation (E)		814	814	815	814	814	814	814	814	814	814	814	814	9,769
	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)		2,499	2,491	2,484	2,476	2,468	2,460	2,453	2,445	2,437	2,429	2,422	2,414	29,478
	a Recoverable Costs Allocated to Energy		192	192	191	190	190	189	189	188	187	187	186	186	2,267
	b Recoverable Costs Allocated to Demand		2,307	2,299	2,293	2,286	2,278	2,271	2,264	2,257	2,250	2,242	2,236	2,228	27,211
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		185	185	185	184	184	183	183	182	181	181	180	179	2,192
13	Retail Demand-Related Recoverable Costs (I)		2,230	2,222	2,216	2,209	2,202	2,195	2,188	2,181	2,175	2,167	2,161	2,153	26,299
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,415	2,407	2,401	2,393	2,386	2,378	2,371	2,363	2,356	2,348	2,341	2,332	28,491

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 2007 - December 2007

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)	(22,213)	(22,397)	(22,581)	(22,765)	(22,949)	(23,133)	(23,317)	(23,501)	(23,685)	(23,869)	(24,053)	(24,237)	(24,421)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	46,710	46,526	46,342	46,158	45,974	45,790	45,606	45,422	45,238	45,054	44,870	44,686	44,502	
6	Average Net Investment		46,618	46,434	46,250	46,066	45,882	45,698	45,514	45,330	45,146	44,962	44,778	44,594	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		343	341	340	338	337	336	334	333	332	330	329	328	4,021
	b Debt Component (Line 6 x Debt Component x 1/12)		97	97	97	96	96	95	95	95	94	94	93	93	1,142
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)		624	622	621	618	617	615	613	612	610	608	606	605	7,371
	a Recoverable Costs Allocated to Energy		48	48	48	48	47	47	47	47	47	47	47	47	568
	b Recoverable Costs Allocated to Demand		576	574	573	570	570	568	566	565	563	561	559	558	6,803
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		46	46	46	46	45	45	45	46	45	46	45	45	546
13	Retail Demand-Related Recoverable Costs (I)		557	555	554	551	551	549	547	546	544	542	540	539	6,575
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		603	601	600	597	596	594	592	592	589	588	585	584	7,121

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 2007 - December 2007

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)	(41,922)	(42,193)	(42,464)	(42,735)	(43,006)	(43,277)	(43,548)	(43,819)	(44,090)	(44,361)	(44,632)	(44,903)	(45,174)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	59,573	59,302	59,031	58,760	58,489	58,218	57,947	57,676	57,405	57,134	56,863	56,592	56,321	
6	Average Net Investment		59,438	59,167	58,896	58,625	58,354	58,083	57,812	57,541	57,270	56,999	56,728	56,457	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		437	435	433	431	429	427	425	423	421	419	417	415	5,112
	b Debt Component (Line 6 x Debt Component x 1/12)		124	123	123	122	122	121	121	120	120	119	118	118	1,451
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)		832	829	827	824	822	819	817	814	812	809	806	804	9,815
	a Recoverable Costs Allocated to Energy		64	64	64	63	63	63	63	63	62	62	62	62	755
	b Recoverable Costs Allocated to Demand		768	765	763	761	759	756	754	751	750	747	744	742	9,060
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		62	62	62	61	61	61	61	61	60	60	60	60	731
13	Retail Demand-Related Recoverable Costs (I)		742	739	737	735	734	731	729	726	725	722	719	717	8,756
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		804	801	799	796	795	792	790	787	785	782	779	777	9,487

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 2007 - December 2007

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)	(24,922)	(25,081)	(25,240)	(25,399)	(25,558)	(25,717)	(25,876)	(26,035)	(26,194)	(26,353)	(26,512)	(26,671)	(26,830)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	34,621	34,462	34,303	34,144	33,985	33,826	33,667	33,508	33,349	33,190	33,031	32,872	32,713	
6	Average Net Investment		34,542	34,383	34,224	34,065	33,906	33,747	33,588	33,429	33,270	33,111	32,952	32,793	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		254	253	251	250	249	248	247	246	244	243	242	241	2,968
	b Debt Component (Line 6 x Debt Component x 1/12)		72	72	71	71	71	70	70	70	69	69	69	68	842
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)		485	484	481	480	479	477	476	475	472	471	470	468	5,718
	a Recoverable Costs Allocated to Energy		37	37	37	37	37	37	37	37	36	36	36	36	440
	b Recoverable Costs Allocated to Demand		448	447	444	443	442	440	439	438	436	435	434	432	5,278
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		36	36	36	36	36	36	36	36	35	35	35	35	428
13	Retail Demand-Related Recoverable Costs (I)		433	432	429	428	427	425	424	423	421	420	419	418	5,099
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		469	468	465	464	463	461	460	459	456	455	454	453	5,527

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) 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 & 1413
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(36,445)	(37,426)	(38,407)	(39,388)	(40,369)	(41,350)	(42,331)	(43,312)	(44,293)	(45,274)	(46,255)	(47,236)	(48,217)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	354,674	353,693	352,712	351,731	350,750	349,769	348,788	347,807	346,826	345,845	344,864	343,883	342,902	
6	Average Net Investment		354,184	353,203	352,222	351,241	350,260	349,279	348,298	347,317	346,336	345,355	344,374	343,393	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,602	2,595	2,588	2,581	2,573	2,566	2,559	2,552	2,545	2,537	2,530	2,523	30,751
	b Debt Component (Line 6 x Debt Component x 1/12)		739	737	735	733	731	729	727	725	723	721	719	717	8,736
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)		4,322	4,313	4,304	4,295	4,285	4,276	4,267	4,258	4,249	4,239	4,230	4,221	51,259
	a Recoverable Costs Allocated to Energy		4,322	4,313	4,304	4,295	4,285	4,276	4,267	4,258	4,249	4,239	4,230	4,221	51,259
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		4,172	4,159	4,159	4,152	4,147	4,137	4,128	4,123	4,107	4,105	4,085	4,071	49,545
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)		4,172	4,159	4,159	4,152	4,147	4,137	4,128	4,123	4,107	4,105	4,085	4,071	49,545

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 2007 - December 2007

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)	(1,003,963)	(1,009,759)	(1,015,555)	(1,021,351)	(1,027,148)	(1,032,944)	(1,038,740)	(1,044,536)	(1,050,332)	(1,056,128)	(1,061,924)	(1,067,720)	(1,073,516)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,778,637	1,772,841	1,767,045	1,761,249	1,755,452	1,749,656	1,743,860	1,738,064	1,732,268	1,726,472	1,720,676	1,714,880	1,709,084	
6	Average Net Investment		1,775,739	1,769,943	1,764,147	1,758,351	1,752,554	1,746,758	1,740,962	1,735,166	1,729,370	1,723,574	1,717,778	1,711,982	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		13,046	13,004	12,961	12,919	12,876	12,833	12,791	12,748	12,706	12,663	12,621	12,578	153,746
	b Debt Component (Line 6 x Debt Component x 1/12)		3,706	3,694	3,682	3,670	3,658	3,645	3,633	3,621	3,609	3,597	3,585	3,573	43,673
8	Investment Expenses														
	a Depreciation (E)		5,796	5,796	5,796	5,797	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	69,553
	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)		22,548	22,494	22,439	22,386	22,330	22,274	22,220	22,165	22,111	22,056	22,002	21,947	266,972
	a Recoverable Costs Allocated to Energy		1,734	1,730	1,726	1,722	1,718	1,713	1,709	1,705	1,701	1,697	1,692	1,688	20,535
	b Recoverable Costs Allocated to Demand		20,814	20,764	20,713	20,664	20,612	20,561	20,511	20,460	20,410	20,359	20,310	20,259	246,437
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		1,674	1,668	1,668	1,665	1,662	1,657	1,653	1,651	1,644	1,643	1,634	1,628	19,847
13	Retail Demand-Related Recoverable Costs (I)		20,116	20,068	20,019	19,971	19,921	19,872	19,824	19,774	19,726	19,677	19,629	19,580	238,177
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		21,790	21,736	21,687	21,636	21,583	21,529	21,477	21,425	21,370	21,320	21,263	21,208	258,024

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

021

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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)	108,949	108,576	108,204	107,831	107,458	107,085	106,712	106,339	105,966	105,593	105,220	104,847	104,474	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	287,911	287,538	287,166	286,793	286,420	286,047	285,674	285,301	284,928	284,555	284,182	283,809	283,436	
6	Average Net Investment		287,725	287,352	286,980	286,607	286,234	285,861	285,488	285,115	284,742	284,369	283,996	283,623	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,114	2,111	2,108	2,106	2,103	2,100	2,097	2,095	2,092	2,089	2,087	2,084	25,186
	b Debt Component (Line 6 x Debt Component x 1/12)		600	600	599	598	597	597	596	595	594	593	593	592	7,154
8	Investment Expenses														
	a Depreciation (E)		373	372	373	373	373	373	373	373	373	373	373	373	4,474
	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)		3,087	3,083	3,081	3,076	3,074	3,070	3,065	3,063	3,059	3,055	3,053	3,048	36,814
	a Recoverable Costs Allocated to Energy		237	237	237	237	237	236	236	236	236	235	235	235	2,834
	b Recoverable Costs Allocated to Demand		2,850	2,846	2,844	2,839	2,837	2,834	2,829	2,827	2,823	2,820	2,818	2,813	33,980
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		229	229	229	229	229	228	228	228	228	228	227	227	2,739
13	Retail Demand-Related Recoverable Costs (I)		2,754	2,751	2,749	2,744	2,742	2,739	2,734	2,732	2,728	2,725	2,724	2,719	32,841
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,983	2,980	2,978	2,973	2,971	2,967	2,962	2,960	2,956	2,953	2,951	2,946	35,580

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 2007 - December 2007

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		13,258	(3,123)	18,743	(434)	(12,536)	9,089	(9,280)	693	(955)	14	0	0	
	b Clearings to Plant		13,258	(3,123)	18,743	(434)	(12,536)	9,089	(9,280)	693	(955)	14	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		921	2,952	44	261	714	473	140	2,647	0	0	364	1,409	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	16,178,324	16,191,582	16,188,459	16,207,202	16,206,768	16,194,232	16,203,321	16,194,041	16,194,734	16,193,779	16,193,793	16,193,793	16,193,793	
3	Less: Accumulated Depreciation (C)	(5,280,222)	(5,331,418)	(5,380,597)	(5,432,704)	(5,484,617)	(5,536,060)	(5,587,740)	(5,639,753)	(5,689,248)	(5,741,389)	(5,793,529)	(5,845,305)	(5,896,036)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,898,102	10,860,164	10,807,862	10,774,498	10,722,151	10,658,172	10,615,581	10,554,288	10,505,486	10,452,390	10,400,264	10,348,488	10,297,757	
6	Average Net Investment		10,879,133	10,834,013	10,791,180	10,748,325	10,690,162	10,636,877	10,584,935	10,529,887	10,478,938	10,426,327	10,374,376	10,323,123	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		79,929	79,597	79,283	78,968	78,541	78,149	77,768	77,363	76,989	76,602	76,221	75,844	935,254
	b Debt Component (Line 6 x Debt Component x 1/12)		22,705	22,611	22,521	22,432	22,310	22,199	22,091	21,976	21,870	21,760	21,651	21,544	265,670
8	Investment Expenses														
	a Depreciation (E)		41,805	41,819	41,839	41,862	41,845	41,841	41,841	41,830	41,829	41,828	41,828	41,828	501,995
	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		31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	382,860
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		186,656	186,244	185,860	185,479	184,913	184,406	183,917	183,386	182,905	182,407	181,917	181,433	2,209,523
	a Recoverable Costs Allocated to Energy		14,358	14,326	14,297	14,268	14,224	14,185	14,147	14,107	14,070	14,031	13,994	13,956	169,963
	b Recoverable Costs Allocated to Demand		172,298	171,918	171,563	171,211	170,689	170,221	169,770	169,279	168,835	168,376	167,923	167,477	2,039,560
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		13,858	13,813	13,814	13,793	13,764	13,723	13,685	13,659	13,599	13,587	13,514	13,460	164,269
13	Retail Demand-Related Recoverable Costs (I)		166,524	166,157	165,813	165,473	164,969	164,516	164,081	163,606	163,177	162,733	162,295	161,864	1,971,208
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		180,382	179,970	179,627	179,266	178,733	178,239	177,766	177,265	176,776	176,320	175,809	175,324	2,135,477

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 2007 - December 2007

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)	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	
3	Less: Accumulated Depreciation (C)	(11,862)	(12,141)	(12,421)	(12,700)	(12,979)	(13,259)	(13,538)	(13,818)	(14,098)	(14,378)	(14,658)	(14,938)	(15,218)	
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)	122,273	121,994	121,714	121,435	121,156	120,876	120,597	120,317	120,037	119,757	119,477	119,197	118,917	
6	Average Net Investment		122,133	121,854	121,575	121,295	121,016	120,736	120,457	120,177	119,897	119,617	119,337	119,057	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		897	895	894	891	889	887	885	883	881	878	877	875	10,632
	b Debt Component (Line 6 x Debt Component x 1/12)		255	254	254	253	253	252	251	251	251	249	249	248	3,020
8	Investment Expenses														
	a Depreciation (E)		279	280	279	279	280	279	280	280	280	280	280	280	3,356
	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)		1,431	1,429	1,427	1,423	1,422	1,418	1,416	1,414	1,412	1,407	1,406	1,403	17,008
	a Recoverable Costs Allocated to Energy		110	110	110	109	109	109	109	109	109	109	109	108	1,310
	b Recoverable Costs Allocated to Demand		1,321	1,319	1,317	1,314	1,313	1,309	1,307	1,305	1,303	1,298	1,297	1,295	15,698
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		106	106	106	105	105	105	105	106	105	106	105	104	1,264
13	Retail Demand-Related Recoverable Costs (I)		1,277	1,275	1,273	1,270	1,269	1,265	1,263	1,261	1,259	1,255	1,254	1,252	15,173
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,383	1,381	1,379	1,375	1,374	1,370	1,368	1,367	1,364	1,361	1,359	1,356	16,437

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

024

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
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

025

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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		(13,909)	1,529	2,631	1,524,890	(112,577)	74,066	19,996	6,317	7,905	230,749	18,425	343,508	
	b Clearings to Plant		23,234	1,529	0	1,921,141	(124,234)	57,185	5,099	(6,750)	1,636	167,786	(319)	501,443	
	c Retirements		0	0	0	0	1,921,077	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	19,918	(19,918)	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)	133,801,191	133,824,425	133,825,954	133,825,954	135,747,095	133,701,784	133,758,969	133,764,068	133,757,318	133,758,954	133,926,739	133,926,421	134,427,864	
3	Less: Accumulated Depreciation (C)	(10,115,423)	(10,502,400)	(10,889,378)	(11,276,354)	(11,645,960)	(10,134,144)	(10,520,836)	(10,907,611)	(11,294,384)	(11,681,150)	(12,068,142)	(12,455,358)	(12,843,242)	
4	CWIP - Non Interest Bearing	444,220	407,077	407,077	409,708	13,457	25,114	41,995	56,892	69,959	76,228	139,191	157,935	(0)	
5	Net Investment (Lines 2 + 3 + 4)	124,129,988	123,729,102	123,343,653	122,959,308	124,114,592	123,592,754	123,280,128	122,913,349	122,532,893	122,154,032	121,997,788	121,628,998	121,584,622	
6	Average Net Investment		123,929,545	123,536,378	123,151,481	123,536,950	123,853,673	123,436,441	123,096,739	122,723,121	122,343,462	122,075,910	121,813,393	121,606,810	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		910,510	907,622	904,794	907,626	909,953	906,888	904,392	901,647	898,857	896,892	894,963	893,445	10,837,589
	b Debt Component (Line 6 x Debt Component x 1/12)		258,641	257,820	257,017	257,822	258,483	257,612	256,903	256,123	255,331	254,772	254,225	253,793	3,078,542
8	Investment Expenses														
	a Depreciation (E)		356,430	356,431	356,429	358,977	358,796	356,145	356,228	356,226	356,219	356,445	356,669	357,337	4,282,332
	b Amortization (F)		1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	22,404
	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)		1,556,128	1,552,420	1,548,787	1,554,972	1,557,779	1,551,192	1,548,070	1,544,543	1,540,954	1,538,656	1,536,404	1,535,122	18,565,027
	a Recoverable Costs Allocated to Energy		1,556,128	1,552,420	1,548,787	1,554,972	1,557,779	1,551,192	1,548,070	1,544,543	1,540,954	1,538,656	1,536,404	1,535,122	18,565,027
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		1,501,956	1,496,862	1,496,473	1,503,158	1,507,444	1,500,644	1,497,499	1,495,444	1,489,394	1,490,008	1,483,730	1,480,520	17,943,132
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)		1,501,956	1,496,862	1,496,473	1,503,158	1,507,444	1,500,644	1,497,499	1,495,444	1,489,394	1,490,008	1,483,730	1,480,520	17,943,132

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) 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 2007 - December 2007

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		57,505	35,087	6,914	(14,196)	0	0	0	0	0	0	0	0	
	b Clearings to Plant		57,505	35,087	6,914	(14,196)	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)	834,527	892,032	927,119	934,033	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	
3	Less: Accumulated Depreciation (C)	(1,321)	(3,624)	(6,050)	(8,532)	(11,004)	(13,457)	(15,910)	(18,363)	(20,816)	(23,269)	(25,722)	(28,175)	(30,628)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	833,206	888,408	921,069	925,501	908,833	906,380	903,927	901,474	899,021	896,568	894,115	891,662	889,209	
6	Average Net Investment		860,807	904,739	923,285	917,167	907,607	905,154	902,701	900,248	897,795	895,342	892,889	890,436	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,324	6,647	6,783	6,738	6,668	6,650	6,632	6,614	6,596	6,578	6,560	6,542	79,332
	b Debt Component (Line 6 x Debt Component x 1/12)		1,797	1,888	1,927	1,914	1,894	1,889	1,884	1,879	1,874	1,869	1,863	1,858	22,536
8	Investment Expenses														
	a Depreciation (E)		2,303	2,426	2,482	2,472	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	29,307
	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)		10,424	10,961	11,192	11,124	11,015	10,992	10,969	10,946	10,923	10,900	10,876	10,853	131,175
	a Recoverable Costs Allocated to Energy		802	843	861	856	847	846	844	842	840	838	837	835	10,091
	b Recoverable Costs Allocated to Demand		9,622	10,118	10,331	10,268	10,168	10,146	10,125	10,104	10,083	10,062	10,039	10,018	121,084
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		774	813	832	827	820	818	816	815	812	812	808	805	9,752
13	Retail Demand-Related Recoverable Costs (I)		9,300	9,779	9,985	9,924	9,827	9,806	9,786	9,765	9,745	9,725	9,703	9,682	117,027
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,074	10,592	10,817	10,751	10,647	10,624	10,602	10,580	10,557	10,537	10,511	10,487	126,779

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

027

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

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)	(5,883)	(6,051)	(6,218)	(6,386)	(6,554)	(6,721)	(6,889)	(7,057)	(7,225)	(7,393)	(7,561)	(7,729)	(7,897)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	56,987	56,819	56,652	56,484	56,316	56,149	55,981	55,813	55,645	55,477	55,309	55,141	54,973	
6	Average Net Investment		56,903	56,736	56,568	56,400	56,233	56,065	55,897	55,729	55,561	55,393	55,225	55,057	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		418	417	416	414	413	412	411	409	408	407	406	405	4,936
	b Debt Component (Line 6 x Debt Component x 1/12)		119	118	118	118	117	117	117	116	116	116	115	115	1,402
8	Investment Expenses														
	a Depreciation (E)		168	167	168	168	167	168	168	168	168	168	168	168	2,014
	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)		705	702	702	700	697	697	696	693	692	691	689	688	8,352
	a Recoverable Costs Allocated to Energy		705	702	702	700	697	697	696	693	692	691	689	688	8,352
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		680	677	678	677	674	674	673	671	669	669	665	664	8,071
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)		680	677	678	677	674	674	673	671	669	669	665	664	8,071

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 2007 - December 2007

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		533,151	375,092	1,128,557	2,065,915	728,411	176,006	409,963	1,164,329	798,918	(601,598)	211,632	2,868,942	
	b Clearings to Plant		0	0	0	0	8,715,023	164,586	3,674	14,143	680	8,976	0	117,490	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	6,808,119	6,808,119	6,808,119	6,808,119	6,808,119	15,523,142	15,687,728	15,691,402	15,705,545	15,706,225	15,715,201	15,715,201	15,832,691	
3	Less: Accumulated Depreciation (C)	(392,470)	(406,651)	(420,833)	(435,014)	(449,195)	(472,454)	(504,960)	(537,641)	(570,341)	(603,056)	(635,781)	(668,515)	(701,455)	
4	CWIP - Non Interest Bearing	3,906,778	4,439,929	4,815,021	5,943,578	8,009,493	22,881	34,301	440,590	1,590,776	2,389,014	1,778,441	1,990,073	4,741,525	
5	Net Investment (Lines 2 + 3 + 4)	10,322,427	10,841,397	11,202,307	12,316,683	14,368,417	15,073,569	15,217,069	15,594,351	16,725,981	17,492,183	16,857,860	17,036,759	19,872,761	
6	Average Net Investment		10,581,912	11,021,852	11,759,495	13,342,550	14,720,993	15,145,319	15,405,710	16,160,166	17,109,082	17,175,022	16,947,310	18,454,760	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		77,745	80,978	86,397	98,028	108,155	111,273	113,186	118,729	125,700	126,185	124,512	135,587	1,306,475
	b Debt Component (Line 6 x Debt Component x 1/12)		22,084	23,003	24,542	27,846	30,723	31,608	32,152	33,726	35,707	35,844	35,369	38,515	371,119
8	Investment Expenses														
	a Depreciation (E)		14,181	14,182	14,181	14,181	23,259	32,506	32,681	32,700	32,715	32,725	32,734	32,940	308,985
	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)		114,010	118,163	125,120	140,055	162,137	175,387	178,019	185,155	194,122	194,754	192,615	207,042	1,986,579
	a Recoverable Costs Allocated to Energy		114,010	118,163	125,120	140,055	162,137	175,387	178,019	185,155	194,122	194,754	192,615	207,042	1,986,579
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		110,041	113,934	120,894	135,388	156,898	169,672	172,204	179,269	187,627	188,596	186,011	199,678	1,920,212
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)		110,041	113,934	120,894	135,388	156,898	169,672	172,204	179,269	187,627	188,596	186,011	199,678	1,920,212

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Smith $6,808,119; Scholz $0. Ending Balances: Crist, $0; Smith $15,715,201; Scholz $117,490.
(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 2007 - December 2007

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		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
Crist Water Conservation Project
P.E. 1227
(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)	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)	(148)	(398)	(648)	(898)	(1,148)	(1,398)	(1,648)	(1,898)	(2,148)	(2,398)	(2,648)	(2,898)	(3,148)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	93,587	93,337	93,087	92,837	92,587	92,337	92,087	91,837	91,587	91,337	91,087	90,837	90,587	
6	Average Net Investment		93,462	93,212	92,962	92,712	92,462	92,212	91,962	91,712	91,462	91,212	90,962	90,712	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		687	685	683	681	679	677	676	674	672	670	668	666	8,118
	b Debt Component (Line 6 x Debt Component x 1/12)		195	195	194	193	193	192	192	191	191	190	190	189	2,305
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)		1,132	1,130	1,127	1,124	1,122	1,119	1,118	1,115	1,113	1,110	1,108	1,105	13,423
	a Recoverable Costs Allocated to Energy		87	87	87	86	86	86	86	86	86	85	85	85	1,032
	b Recoverable Costs Allocated to Demand		1,045	1,043	1,040	1,038	1,036	1,033	1,032	1,029	1,027	1,025	1,023	1,020	12,391
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		84	84	84	83	83	83	83	83	83	82	82	82	996
13	Retail Demand-Related Recoverable Costs (I)		1,010	1,008	1,005	1,003	1,001	998	997	995	993	991	989	986	11,976
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,094	1,092	1,089	1,086	1,084	1,081	1,080	1,078	1,076	1,073	1,071	1,068	12,972

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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Condenser Tubes
P.E. 1204
(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)	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	
3	Less: Accumulated Depreciation (C)	(123,837)	(139,379)	(154,921)	(170,463)	(186,005)	(201,547)	(217,089)	(232,631)	(248,173)	(263,715)	(279,257)	(294,799)	(310,341)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,703,870	5,688,328	5,672,786	5,657,244	5,641,702	5,626,160	5,610,618	5,595,076	5,579,534	5,563,992	5,548,450	5,532,908	5,517,366	
6	Average Net Investment		5,696,099	5,680,557	5,665,015	5,649,473	5,633,931	5,618,389	5,602,847	5,587,305	5,571,763	5,556,221	5,540,679	5,525,137	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		41,849	41,735	41,621	41,507	41,392	41,278	41,164	41,050	40,936	40,822	40,707	40,593	494,654
	b Debt Component (Line 6 x Debt Component x 1/12)		11,888	11,855	11,823	11,790	11,758	11,726	11,693	11,661	11,628	11,596	11,563	11,531	140,512
8	Investment Expenses														
	a Depreciation (E)		15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	186,504
	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)		69,279	69,132	68,986	68,839	68,692	68,546	68,399	68,253	68,106	67,960	67,812	67,666	821,670
	a Recoverable Costs Allocated to Energy		5,329	5,318	5,307	5,295	5,284	5,273	5,261	5,250	5,239	5,228	5,216	5,205	63,205
	b Recoverable Costs Allocated to Demand		63,950	63,814	63,679	63,544	63,408	63,273	63,138	63,003	62,867	62,732	62,596	62,461	758,465
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		5,143	5,128	5,128	5,119	5,113	5,101	5,089	5,083	5,064	5,063	5,037	5,020	61,088
13	Retail Demand-Related Recoverable Costs (I)		61,807	61,675	61,545	61,414	61,283	61,153	61,022	60,892	60,760	60,630	60,498	60,368	733,047
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		66,950	66,803	66,673	66,533	66,396	66,254	66,111	65,975	65,824	65,693	65,535	65,388	794,135

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 2007 - December 2007

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, 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		66,622	42,172	74,636	24,425	666,252	27,146,843	214,067	(10,283)	260,363	504,067	92,267	1,445,910	
	b Clearings to Plant		38,759	(286)	0	0	672,015	27,059,453	247,228	(74,782)	75,772	368,338	(32,369)	1,484,691	
	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	38,759	38,473	38,473	38,473	710,488	27,769,941	28,017,169	27,942,387	28,018,160	28,386,498	28,354,128	29,838,819	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	(758)	(38,355)	(112,352)	(186,566)	(260,754)	(335,428)	(410,478)	(487,157)	
4	CWIP - Non Interest Bearing	0	27,863	70,321	144,957	169,382	163,619	251,009	217,848	282,347	466,937	602,666	727,302	688,521	
5	Net Investment (Lines 2 + 3 + 4)	0	66,622	108,794	183,430	207,855	873,349	27,982,595	28,122,665	28,038,168	28,224,343	28,653,736	28,670,953	30,040,184	
6	Average Net Investment		33,311	87,708	146,112	195,643	540,602	14,427,972	28,052,630	28,080,417	28,131,255	28,439,039	28,662,344	29,355,568	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		245	644	1,073	1,437	3,972	106,002	206,103	206,307	206,680	208,942	210,582	215,675	1,367,662
	b Debt Component (Line 6 x Debt Component x 1/12)		70	183	305	408	1,128	30,111	58,546	58,604	58,710	59,352	59,818	61,265	388,500
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	758	37,597	73,997	74,214	74,188	74,674	75,050	76,679	487,157
	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)		315	827	1,378	1,845	5,858	173,710	338,646	339,125	339,578	342,968	345,450	353,619	2,243,319
	a Recoverable Costs Allocated to Energy		315	827	1,378	1,845	5,858	173,710	338,646	339,125	339,578	342,968	345,450	353,619	2,243,319
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		304	797	1,331	1,784	5,669	168,049	327,583	328,345	328,216	332,124	333,607	341,041	2,168,850
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)		304	797	1,331	1,784	5,669	168,049	327,583	328,345	328,216	332,124	333,607	341,041	2,168,850

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $0; Smith $0; Daniel $0, Scholz $0. Ending Balances: Crist $29,626,569; Smith $212,250, Daniel $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%, 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 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 2007 - December 2007

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	23,633	7	9	(22)	27	0	0	0	
	b Clearings to Plant		0	0	0	0	23,633	7	9	(22)	27	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	23,633	23,640	23,649	23,627	23,654	23,654	23,654	23,654	
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	23,633	23,640	23,649	23,627	23,654	23,654	23,654	23,654	
6	Average Net Investment		0	0	0	0	11,817	23,637	23,644	23,638	23,641	23,654	23,654	23,654	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	87	174	174	174	174	174	174	174	1,305
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	25	49	49	49	49	49	49	49	368
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	112	223	223	223	223	223	223	223	1,673
	a Recoverable Costs Allocated to Energy		0	0	0	0	112	223	223	223	223	223	223	223	1,673
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	108	216	216	216	216	216	215	215	1,618
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	108	216	216	216	216	216	215	215	1,618

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 2007 - December 2007

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		14,250,000	0	0	29,755	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	518,044	0	49,167	(39,566)	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	10,583,118	24,381,657	23,458,100	22,443,092	21,754,017	20,818,122	19,805,303	18,801,110	17,722,583	16,840,596	15,960,746	15,232,186	14,376,400	
	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	(931,498)	(926,430)	(921,363)	(916,296)	(911,229)	(1,379,054)	(1,328,835)	(1,322,070)	(1,234,485)	(1,186,466)	(1,138,447)	(1,090,428)	(1,042,409)	
3	Total Working Capital Balance	9,651,620	23,455,227	22,536,737	21,526,796	20,842,788	19,439,068	18,476,468	17,479,040	16,488,098	15,654,130	14,822,299	14,141,758	13,333,991	
4	Average Net Working Capital Balance		16,553,424	22,995,982	22,031,767	21,184,792	20,140,928	18,957,768	17,977,754	16,983,569	16,071,114	15,238,214	14,482,028	13,737,874	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		121,618	168,951	161,867	155,645	147,975	139,283	132,083	124,778	118,074	111,955	106,399	100,932	1,589,560
	b Debt Component (Line 4 x Debt Component x 1/12)		34,547	47,993	45,980	44,213	42,034	39,565	37,520	35,445	33,540	31,802	30,224	28,671	451,534
6	Total Return Component (D)		156,165	216,944	207,847	199,858	190,009	178,848	169,603	160,223	151,614	143,757	136,623	129,603	2,041,094
7	Expenses														
	a Gains		(5,068)	(5,067)	(5,067)	(5,067)	(50,219)	(50,219)	(55,932)	(48,019)	(48,019)	(48,019)	(48,019)	(48,019)	(416,734)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		451,461	923,557	1,015,008	718,830	935,895	1,012,819	1,004,193	1,078,527	881,987	879,850	728,560	855,786	10,486,473
8	Net Expenses (E)		446,393	918,490	1,009,941	713,763	885,676	962,600	948,261	1,030,508	833,968	831,831	680,541	807,767	10,069,739
9	Total System Recoverable Expenses (Lines 6 + 8)		602,558	1,135,434	1,217,788	913,621	1,075,685	1,141,448	1,117,864	1,190,731	985,582	975,588	817,164	937,370	12,110,833
	a Recoverable Costs Allocated to Energy		602,558	1,135,434	1,217,788	913,621	1,075,685	1,141,448	1,117,864	1,190,731	985,582	975,588	817,164	937,370	12,110,833
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9666564	0.9675339	0.9658638	0.9677051	0.9650406	0.9637568	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (B)		581,582	1,094,799	1,176,655	883,178	1,040,928	1,104,252	1,081,347	1,152,879	952,604	944,742	789,148	904,029	11,706,143
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)		581,582	1,094,799	1,176,655	883,178	1,040,928	1,104,252	1,081,347	1,152,879	952,604	944,742	789,148	904,029	11,706,143

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

035

Schedule 1E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2008 - December 2008

Line		Period Amount ($)
1	Over/(Under) Recovery for the current period (Schedule 2E, Line 5)	(2,812,206)
2	Interest Provision (Schedule 2E, Line 6)	1,916
3	Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2009 - December 2009 (Lines 1 + 2)	(2,810,290)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 26
COMPANY Gulf Power Co. (Direct)
WITNESS Susan Ritenour (SDR-2)
DATE 11-04-08

Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated 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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	4,058,103	3,422,308	3,346,536	3,480,636	4,329,372	4,831,384	5,154,225	5,263,968	4,418,933	3,928,832	3,325,501	3,865,659	49,425,457
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	3,492,341	4,341,077	4,843,089	5,165,930	5,275,673	4,430,638	3,940,537	3,337,206	3,877,363	49,565,916
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	1,193,539	1,711,849	905,879	1,280,921	930,661	1,519,145	1,329,710	1,322,023	1,370,117	1,162,276	1,013,255	962,395	14,701,770
	b Capital Investment Projects (Schedule 7E, Line 9)	2,878,252	2,907,558	2,946,622	3,072,901	3,180,622	3,206,609	3,225,071	3,235,439	3,241,279	3,254,184	3,251,782	3,276,033	37,676,352
	c **Total Jurisdictional ECRC Costs**	4,071,791	4,619,407	3,852,501	4,353,822	4,111,283	4,725,754	4,554,781	4,557,462	4,611,396	4,416,460	4,265,037	4,238,428	52,378,122
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	(1,983)	(1,185,394)	(494,260)	(861,481)	229,794	117,335	611,149	718,211	(180,758)	(475,923)	(927,831)	(361,065)	(2,812,206)
6	Interest Provision (Schedule 3E, Line 10)	5,387	2,577	369	(1,217)	(1,895)	(1,429)	(718)	614	1,140	448	(1,009)	(2,351)	1,916
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2007	(647,455)	(655,756)	(1,850,278)	(2,355,874)	(3,230,277)	(3,014,083)	(2,909,882)	(2,311,156)	(1,604,036)	(1,795,359)	(2,282,539)	(3,223,084)	(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)	1,602,629	408,107	(97,489)	(971,892)	(755,698)	(651,497)	(52,771)	654,349	463,026	(24,154)	(964,699)	(1,339,819)	(1,339,819)

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2008 - December 2008

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)	1,610,930	1,602,629	408,107	(97,489)	(971,892)	(755,698)	(651,497)	(52,771)	654,349	463,026	(24,154)	(964,699)	
2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	1,597,242	405,530	(97,858)	(970,675)	(753,803)	(650,068)	(52,053)	653,735	461,886	(24,602)	(963,690)	(1,337,468)	
3 Total of Beginning & Ending True-up (Lines 1 + 2)	3,208,173	2,008,160	310,250	(1,068,163)	(1,725,694)	(1,405,765)	(703,549)	600,965	1,116,236	438,425	(987,843)	(2,302,166)	
4 Average True-Up Amount (Line 3 x 1/2)	1,604,086	1,004,080	155,125	(534,082)	(862,847)	(702,883)	(351,775)	300,482	558,118	219,212	(493,922)	(1,151,083)	
5 Interest Rate (First Day of Reporting Business Month)	0.049800	0.030800	0.030800	0.026300	0.028400	0.024300	0.024500	0.024500	0.024500	0.024500	0.024500	0.024500	
6 Interest Rate (First Day of Subsequent Business Month)	0.030800	0.030800	0.026300	0.028400	0.024300	0.024500	0.024500	0.024500	0.024500	0.024500	0.024500	0.024500	
7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.080600	0.061600	0.057100	0.054700	0.052700	0.048800	0.049000	0.049000	0.049000	0.049000	0.049000	0.049000	
8 Average Interest Rate (Line 7 x 1/2)	0.040300	0.030800	0.028550	0.027350	0.026350	0.024400	0.024500	0.024500	0.024500	0.024500	0.024500	0.024500	
9 Monthly Average Interest Rate (Line 8 x 1/12)	0.003358	0.002567	0.002379	0.002279	0.002196	0.002033	0.002042	0.002042	0.002042	0.002042	0.002042	0.002042	
10 Interest Provision for the Month (Line 4 x Line 9)	5,387	2,577	369	(1,217)	(1,895)	(1,429)	(718)	614	1,140	448	(1,009)	(2,351)	1,916

Schedule 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2008 - December 2008

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	824,622	779,874	44,748	5.7	%
.3	Title V	98,173	91,571	6,602	7.2	%
.4	Asbestos Fees	2,184	2,250	(66)	(2.9)	%
.5	Emission Monitoring	530,117	663,054	(132,937)	(20.0)	%
.6	General Water Quality	366,108	338,913	27,195	8.0	%
.7	Groundwater Contamination Investigation	1,504,437	1,396,476	107,961	7.7	%
.8	State NPDES Administration	42,000	42,000	0	0.0	%
.9	Lead and Copper Rule	21,348	21,500	(152)	(0.7)	%
.10	Env Auditing/Assessment	6,700	1,300	5,400	415.4	%
.11	General Solid & Hazardous Waste	373,491	331,185	42,306	12.8	%
.12	Above Ground Storage Tanks	177,549	180,500	(2,951)	(1.6)	%
.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	247,939	238,000	9,939	4.2	%
.17	Gulf Coast Ozone Study	0	0	0	0.0	%
.18	SPCC Substation Project	0	0	0	0.0	%
.19	FDEP NOX Reduction Agreement	3,713,809	3,061,705	652,104	21.3	%
.20	CAIR/CAMR/CAVR Compliance Program	473,267	275,401	197,866	71.8	%
.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	6,835,142	6,725,150	109,992	1.6	%
2	Total O & M Activities	15,216,886	14,148,879	1,068,007	7.5	%
3	Recoverable Costs Allocated to Energy	12,723,069	11,834,755	888,314	7.5	%
4	Recoverable Costs Allocated to Demand	2,493,817	2,314,124	179,693	7.8	%

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-06-0972-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated 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	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	-	700,225	23	-	-	-	-	-	124,374	-	-	-	824,622	0	824,622
	.3 Title V	8,180	9,382	8,735	7,963	6,200	8,317	9,441	10,811	7,275	7,400	7,275	7,194	98,173	0	98,173
	.4 Asbestos Fees	1,500	-	300	(1,537)	(79)	-	-	-	-	500	-	1,500	2,184	2,184	0
	.5 Emission Monitoring	30,700	31,550	59,328	39,967	43,127	40,897	40,391	61,586	62,891	40,391	40,391	38,898	530,117	0	530,117
	.6 General Water Quality	9,714	25,580	12,045	15,198	28,455	47,583	32,427	27,252	49,065	64,265	33,202	21,322	366,108	366,108	0
	.7 Groundwater Contamination Investigation	(6,161)	64,126	84,006	62,604	122,829	561,836	107,795	116,696	97,294	98,012	98,212	97,188	1,504,437	1,504,437	0
	.8 State NPDES Administration	-	-	-	-	-	-	-	-	-	-	-	42,000	42,000	42,000	0
	.9 Lead and Copper Rule	3,583	-	3,036	-	547	3,382	3,600	-	-	3,600	-	3,600	21,348	21,348	0
	.10 Env Auditing/Assessment	-	-	3,909	377	414	-	-	-	1,000	-	-	1,000	6,700	6,700	0
	.11 General Solid & Hazardous Waste	19,751	15,681	55,590	30,230	36,632	35,756	29,344	36,208	28,732	28,782	27,757	29,028	373,491	373,491	0
	.12 Above Ground Storage Tanks	(7,688)	7,188	35,684	24,143	(7,078)	5,491	37,800	-	30,730	20,000	27,279	4,000	177,549	177,549	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	22,800	22,100	22,100	22,100	22,100	23,500	247,939	0	247,939
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.19 FDEP NOX Reduction Agreement	596,519	389,227	169,915	438,599	207,430	258,005	297,248	299,484	324,337	246,599	231,718	254,728	3,713,809	0	3,713,809
	.20 CAIR/CAMR/CAVR Compliance Program	-	-	-	169,999	55,534	(10,665)	96,974	96,973	11,391	17,687	17,687	17,687	473,267	0	473,267
	.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	697,864	696,618	659,060	654,252	547,051	457,229	6,835,142	0	6,835,142
2	Total of O & M Activities	1,237,903	1,771,481	937,126	1,321,978	960,957	1,570,646	1,375,684	1,367,728	1,418,249	1,203,588	1,052,672	998,874	15,216,886	2,493,817	12,723,069
3	Recoverable Costs Allocated to Energy	1,217,204	1,658,906	742,556	1,190,963	779,237	916,598	1,164,718	1,187,572	1,211,428	988,429	866,222	799,236	12,723,069		
4	Recoverable Costs Allocated to Demand	20,699	112,575	194,570	131,015	181,720	654,048	210,966	180,156	206,821	215,159	186,450	199,638	2,493,817		
5	Retail Energy Jurisdictional Factor	0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224			
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	1,603,302	718,271	1,154,594	755,444	888,501	1,126,293	1,148,314	1,170,697	954,816	833,477	769,901	12,297,191		
8	Jurisdictional Demand Recoverable Costs (B)	19,958	108,547	187,608	126,327	175,217	630,644	203,417	173,709	199,420	207,460	179,778	192,494	2,404,579		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,193,539	1,711,849	905,879	1,280,921	930,661	1,519,145	1,329,710	1,322,023	1,370,117	1,162,276	1,013,255	962,395	14,701,770		

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 2008 - December 2008

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	46,344	46,344	0	0.0	%
.2	Crist 5, 6 & 7 Precipitator Projects	1,951,133	1,954,342	(3,209)	(0.2)	%
.3	Crist 7 Flue Gas Conditioning	168,693	168,693	0	0.0	%
.4	Low NOx Burners, Crist 6 & 7	2,052,284	2,052,284	0	0.0	%
.5	CEMS - Plants Crist, Scholz, Smith, & Daniel	832,135	878,007	(45,872)	(5.2)	%
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	104,412	104,414	(2)	(0.0)	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	27,825	27,823	2	0.0	%
.8	Crist Cooling Tower Cell	59,391	62,370	(2,979)	(4.8)	%
.9	Crist 1-5 Dechlorination	28,374	28,374	0	0.0	%
.10	Crist Diesel Fuel Oil Remediation	7,121	7,121	0	0.0	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	9,446	9,446	0	0.0	%
.12	Crist IWW Sampling System	5,502	5,502	0	0.0	%
.13	Sodium Injection System	49,923	49,923	0	0.0	%
.14	Smith Stormwater Collection System	259,098	259,098	0	0.0	%
.15	Smith Waste Water Treatment Facility	36,309	36,310	(1)	(0.0)	%
.16	Daniel Ash Management Project	2,113,083	2,105,935	7,148	0.3	%
.17	Smith Water Conservation	16,633	16,631	2	0.0	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	18,263,765	18,231,592	32,173	0.2	%
.20	Crist Stormwater Collection System	128,437	128,437	0	0.0	%
.21	Crist Common FTIR Monitor	8,126	8,126	0	0.0	%
.22	Precipitator Upgrades for CAM Compliance	3,835,676	3,785,371	50,305	1.3	%
.23	Plant Groundwater Investigation	0	0	0	0.0	%
.24	Crist Water Conservation	13,086	13,086	0	0.0	%
.25	Crist Condenser Tubes	808,517	816,187	(7,670)	(0.9)	%
.26	CAIR/CAMR/CAVR Compliance	7,056,845	5,680,729	1,376,116	24.2	%
.27	General Water Quality	7,137	7,136	1	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	1,101,320	1,013,939	87,381	36.0	%
2	Total Investment Projects - Recoverable Costs	38,990,615	37,497,220	1,493,395	4.0	%
3	Recoverable Costs Allocated to Energy	35,651,631	34,148,413	1,503,218	4.4	%
4	Recoverable Costs Allocated to Demand	3,338,984	3,348,804	(9,820)	(0.3)	%

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-06-0972-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 2008 - December 2008

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	3,998	3,974	3,948	3,924	3,899	3,875	3,849	3,825	3,800	3,776	3,750	3,726	46,344	0	46,344
.2	Crist 5, 6 & 7 Precipitator Projects	164,511	164,039	163,566	163,092	162,620	162,147	161,673	161,201	161,436	161,670	161,668	163,510	1,951,133	0	1,951,133
.3	Crist 7 Flue Gas Conditioning	14,068	14,067	14,064	14,063	14,060	14,059	14,057	14,055	14,053	14,051	14,049	14,047	168,693	0	168,693
.4	Low NOx Burners, Crist 6 & 7	172,283	172,054	171,825	171,596	171,367	171,138	170,909	170,680	170,452	170,222	169,993	169,765	2,052,284	0	2,052,284
.5	CEMS - Plants Crist, Scholz, Smith, & Daniel	64,251	64,141	64,029	65,226	66,424	71,495	74,151	71,991	72,237	72,831	72,969	72,390	832,135	0	832,135
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	8,797	8,779	8,762	8,742	8,727	8,710	8,693	8,675	8,658	8,640	8,623	8,606	104,412	96,380	8,032
.7	Raw Water Well Flowmeters - Plants Crist & Smith	2,349	2,343	2,339	2,333	2,328	2,322	2,316	2,310	2,304	2,300	2,293	2,288	27,825	25,684	2,141
.8	Crist Cooling Tower Cell	4,970	4,951	4,956	4,953	4,950	4,949	4,948	4,946	4,944	4,943	4,941	4,940	59,391	54,823	4,568
.9	Crist 1-5 Dechlorination	2,406	2,399	2,391	2,383	2,376	2,368	2,361	2,353	2,346	2,338	2,330	2,323	28,374	26,191	2,183
.10	Crist Diesel Fuel Oil Remediation	603	601	600	598	596	595	592	591	589	587	586	583	7,121	6,574	547
.11	Crist Bulk Tanker Unload Sec Contain Struc	801	799	796	794	791	788	786	783	781	778	776	773	9,446	8,720	726
.12	Crist IWW Sampling System	467	466	463	462	461	459	458	457	454	453	452	450	5,502	5,078	424
.13	Sodium Injection System	4,212	4,202	4,193	4,183	4,174	4,165	4,155	4,146	4,137	4,128	4,119	4,109	49,923	0	49,923
.14	Smith Stormwater Collection System	21,892	21,838	21,783	21,729	21,673	21,618	21,564	21,509	21,455	21,400	21,346	21,291	259,098	239,167	19,931
.15	Smith Waste Water Treatment Facility	3,045	3,043	3,037	3,034	3,031	3,027	3,024	3,021	3,017	3,013	3,011	3,006	36,309	33,519	2,790
.16	Daniel Ash Management Project	178,746	178,269	177,792	177,303	176,813	176,327	175,836	175,344	174,867	174,408	173,935	173,443	2,113,083	1,950,537	162,546
.17	Smith Water Conservation	1,400	1,398	1,395	1,393	1,390	1,387	1,386	1,381	1,379	1,378	1,374	1,372	16,633	15,354	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	1,534,267	1,533,931	1,533,513	1,529,853	1,526,184	1,522,535	1,518,884	1,515,214	1,513,410	1,514,040	1,512,803	1,509,131	18,263,765	0	18,263,765
.20	Crist Stormwater Collection System	10,830	10,807	10,784	10,761	10,738	10,715	10,692	10,668	10,645	10,622	10,599	10,576	128,437	118,557	9,880
.21	Crist Common FTIR Monitor	686	684	683	682	679	678	676	675	673	671	670	669	8,126	0	8,126
.22	Precipitator Upgrades for CAM Compliance	232,459	258,160	298,219	330,806	338,909	340,674	340,763	340,464	339,801	339,137	338,474	337,810	3,835,676	0	3,835,676
.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	1,077	13,086	12,079	1,007
.25	Crist Condenser Tubes	67,520	67,373	67,227	67,079	66,933	66,853	67,178	67,554	67,526	67,696	67,864	67,714	808,517	746,323	62,194
.26	CAIR/CAMR/CAVR Compliance	365,810	370,957	375,764	475,971	589,484	621,643	656,088	680,903	698,020	718,684	736,517	767,004	7,056,845	0	7,056,845
.27	General Water Quality	615	611	608	604	601	597	593	589	585	582	578	574	7,137	0	7,137
.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	89,179	82,411	76,015	69,821	64,154	59,417	1,101,320	0	1,101,320
2	Total Investment Projects - Recoverable Costs	2,985,224	3,009,054	3,047,140	3,171,206	3,282,308	3,309,481	3,335,901	3,346,833	3,354,669	3,369,251	3,378,954	3,400,594	38,990,615	3,338,986	35,651,629
3	Recoverable Costs Allocated to Energy	2,703,750	2,728,286	2,767,059	2,891,826	3,003,630	3,031,442	3,058,126	3,069,283	3,077,697	3,092,661	3,102,759	3,125,112	35,651,631		
4	Recoverable Costs Allocated to Demand	281,474	280,768	280,081	279,380	278,678	278,039	277,775	277,550	276,972	276,590	276,195	275,482	3,338,984		
5	Retail Energy Jurisdictional Factor	0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224			
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)	2,606,850	2,636,837	2,676,563	2,803,518	2,911,916	2,938,519	2,957,236	2,967,821	2,974,218	2,987,491	2,985,470	3,010,409	34,456,848		
8	Jurisdictional Demand Recoverable Costs (C)	271,402	270,721	270,059	269,383	268,706	268,090	267,835	267,618	267,061	266,693	266,312	265,624	3,219,504		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	2,878,252	2,907,558	2,946,622	3,072,901	3,180,622	3,206,609	3,225,071	3,235,439	3,241,279	3,254,184	3,251,782	3,276,033	37,676,352		

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9, Page 28 of Schedule 8E, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Docket No. 080007-EI
ECRC 2008 Est/Act True-up
Exhibit SDR-2, Page 7 of 38

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated 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	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)	(73,214)	(75,837)	(78,460)	(81,083)	(83,706)	(86,329)	(88,952)	(91,575)	(94,198)	(96,821)	(99,444)	(102,067)	(104,690)	
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)	147,080	144,457	141,834	139,211	136,588	133,965	131,342	128,719	126,096	123,473	120,850	118,227	115,604	
6	Average Net Investment		145,769	143,146	140,523	137,900	135,277	132,654	130,031	127,408	124,785	122,162	119,539	116,916	
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	2,623	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)		3,998	3,974	3,948	3,924	3,899	3,875	3,849	3,825	3,800	3,776	3,750	3,726	46,344
	a Recoverable Costs Allocated to Energy		3,998	3,974	3,948	3,924	3,899	3,875	3,849	3,825	3,800	3,776	3,750	3,726	46,344
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	3,841	3,819	3,804	3,780	3,756	3,722	3,699	3,672	3,648	3,608	3,589	44,793
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	3,841	3,819	3,804	3,780	3,756	3,722	3,699	3,672	3,648	3,608	3,589	44,793

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 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	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	150,000	0	100,000	250,000	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	500,000	
	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)	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	15,031,878	
3	Less: Accumulated Depreciation (C)	(2,382,646)	(2,432,778)	(2,482,910)	(2,533,042)	(2,583,174)	(2,633,306)	(2,683,438)	(2,733,570)	(2,783,702)	(2,833,834)	(2,883,966)	(2,934,098)	(2,984,897)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	150,000	150,000	250,000	0	
5	Net Investment (Lines 2 + 3 + 4)	12,149,232	12,099,100	12,048,968	11,998,836	11,948,704	11,898,572	11,848,440	11,798,308	11,748,176	11,848,044	11,797,912	11,847,780	12,046,981	
6	Average Net Investment		12,124,166	12,074,034	12,023,902	11,973,770	11,923,638	11,873,506	11,823,374	11,773,242	11,798,110	11,822,978	11,822,846	11,947,381	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		89,076	88,708	88,340	87,971	87,603	87,235	86,866	86,498	86,681	86,863	86,862	87,777	1,050,480
	b Debt Component (Line 6 x Debt Component x 1/12)		25,303	25,199	25,094	24,989	24,885	24,780	24,675	24,571	24,623	24,675	24,674	24,934	298,402
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	39,424	465,751
	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)		164,511	164,039	163,566	163,092	162,620	162,147	161,673	161,201	161,436	161,670	161,668	163,510	1,951,133
	a Recoverable Costs Allocated to Energy		164,511	164,039	163,566	163,092	162,620	162,147	161,673	161,201	161,436	161,670	161,668	163,510	1,951,133
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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)		158,615	158,541	158,217	158,113	157,655	157,177	156,339	155,872	156,008	156,172	155,557	157,509	1,885,775
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)		158,615	158,541	158,217	158,113	157,655	157,177	156,339	155,872	156,008	156,172	155,557	157,509	1,885,775

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 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	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)	1,469,711	1,469,507	1,469,303	1,469,099	1,468,895	1,468,691	1,468,487	1,468,283	1,468,079	1,467,875	1,467,671	1,467,467	1,467,263	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,469,711	1,469,507	1,469,303	1,469,099	1,468,895	1,468,691	1,468,487	1,468,283	1,468,079	1,467,875	1,467,671	1,467,467	1,467,263	
6	Average Net Investment		1,469,609	1,469,405	1,469,201	1,468,997	1,468,793	1,468,589	1,468,385	1,468,181	1,467,977	1,467,773	1,467,569	1,467,365	
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	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)		14,068	14,067	14,064	14,063	14,060	14,059	14,057	14,055	14,053	14,051	14,049	14,047	168,693
	a Recoverable Costs Allocated to Energy		14,068	14,067	14,064	14,063	14,060	14,059	14,057	14,055	14,053	14,051	14,049	14,047	168,693
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	13,634	13,631	13,628	13,593	13,590	13,581	13,573	13,518	13,531	163,042
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	13,634	13,631	13,628	13,593	13,590	13,581	13,573	13,518	13,531	163,042

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 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 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	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)	6,604,119	6,579,855	6,555,591	6,531,327	6,507,063	6,482,799	6,458,535	6,434,271	6,410,007	6,385,743	6,361,479	6,337,215	6,312,951	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	15,702,042	15,677,778	15,653,514	15,629,250	15,604,986	15,580,722	15,556,458	15,532,194	15,507,930	15,483,666	15,459,402	15,435,138	15,410,874	
6	Average Net Investment		15,689,910	15,665,646	15,641,382	15,617,118	15,592,854	15,568,590	15,544,326	15,520,062	15,495,798	15,471,534	15,447,270	15,423,006	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		115,274	115,096	114,917	114,739	114,561	114,382	114,204	114,026	113,848	113,669	113,491	113,313	1,371,520
	b Debt Component (Line 6 x Debt Component x 1/12)		32,745	32,694	32,644	32,593	32,542	32,492	32,441	32,390	32,340	32,289	32,238	32,188	389,596
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)		172,283	172,054	171,825	171,596	171,367	171,138	170,909	170,680	170,452	170,222	169,993	169,765	2,052,284
	a Recoverable Costs Allocated to Energy		172,283	172,054	171,825	171,596	171,367	171,138	170,909	170,680	170,452	170,222	169,993	169,765	2,052,284
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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)		166,109	166,287	166,206	166,356	166,134	165,892	165,271	165,038	164,721	164,433	163,567	163,534	1,983,548
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)		166,109	166,287	166,206	166,356	166,134	165,892	165,271	165,038	164,721	164,433	163,567	163,534	1,983,548

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 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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	277,167	443	1,097,889	(634,193)	108,698	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	349,275	0	0	687,930	0	0	
	c Retirements		0	0	0	0	0	0	0	85,586	0	0	433,427	0	
	d Cost of Removal		0	0	0	0	0	0	300	1,000	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)	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,647,753	4,562,167	4,562,167	5,250,097	4,816,670	4,816,670	
3	Less: Accumulated Depreciation (C)	949,696	937,925	926,154	914,383	902,612	890,841	879,070	867,018	940,820	928,187	914,838	1,334,651	1,321,489	
4	CWIP - Non Interest Bearing	187,201	187,201	187,201	187,201	464,367	464,810	1,562,700	579,232	687,930	687,930	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	5,435,375	5,423,604	5,411,833	5,400,062	5,665,457	5,654,129	6,740,248	6,094,003	6,190,917	6,178,284	6,164,935	6,151,321	6,138,159	
6	Average Net Investment		5,429,489	5,417,718	5,405,947	5,532,760	5,659,793	6,197,188	6,417,125	6,142,460	6,184,600	6,171,609	6,158,128	6,144,740	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		39,890	39,804	39,717	40,649	41,582	45,531	47,147	45,129	45,438	45,343	45,244	45,145	520,619
	b Debt Component (Line 6 x Debt Component x 1/12)		11,331	11,307	11,282	11,547	11,812	12,934	13,393	12,819	12,907	12,880	12,852	12,824	147,888
8	Investment Expenses														
	a Depreciation (E)		11,639	11,639	11,639	11,639	11,639	11,639	12,220	12,652	12,501	13,217	13,482	13,030	146,936
	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)		64,251	64,141	64,029	65,226	66,424	71,495	74,151	71,991	72,237	72,831	72,969	72,390	832,135
	a Recoverable Costs Allocated to Energy		64,251	64,141	64,029	65,226	66,424	71,495	74,151	71,991	72,237	72,831	72,969	72,390	832,135
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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)		61,948	61,991	61,935	63,234	64,396	69,303	71,705	69,611	69,808	70,354	70,211	69,733	804,229
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)		61,948	61,991	61,935	63,234	64,396	69,303	71,705	69,611	69,808	70,354	70,211	69,733	804,229

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 $987,947; Smith $943,402; Daniel $652,719.
(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 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	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)	(179,301)	(181,137)	(182,973)	(184,809)	(186,645)	(188,481)	(190,317)	(192,153)	(193,989)	(195,825)	(197,661)	(199,497)	(201,333)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	738,723	736,887	735,051	733,215	731,379	729,543	727,707	725,871	724,035	722,199	720,363	718,527	716,691	
6	Average Net Investment		737,806	735,970	734,134	732,298	730,462	728,626	726,790	724,954	723,118	721,282	719,446	717,610	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,421	5,407	5,394	5,380	5,367	5,353	5,340	5,326	5,313	5,299	5,286	5,272	64,158
	b Debt Component (Line 6 x Debt Component x 1/12)		1,540	1,536	1,532	1,528	1,524	1,521	1,517	1,513	1,509	1,505	1,501	1,498	18,224
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	1,834	22,030
	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)		8,797	8,779	8,762	8,742	8,727	8,710	8,693	8,675	8,658	8,640	8,623	8,606	104,412
	a Recoverable Costs Allocated to Energy		676	676	675	672	671	670	669	668	665	664	663	663	8,032
	b Recoverable Costs Allocated to Demand		8,121	8,103	8,085	8,070	8,056	8,040	8,024	8,007	7,993	7,976	7,960	7,943	96,378
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	647	646	643	641	638	639	7,763
13	Retail Demand-Related Recoverable Costs (I)		7,830	7,813	7,796	7,781	7,768	7,752	7,737	7,720	7,707	7,691	7,675	7,659	92,929
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,482	8,466	8,449	8,432	8,419	8,401	8,384	8,366	8,350	8,332	8,313	8,298	100,692

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 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	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)	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	
3	Less: Accumulated Depreciation (C)	(56,572)	(57,166)	(57,760)	(58,354)	(58,948)	(59,542)	(60,136)	(60,730)	(61,324)	(61,918)	(62,512)	(63,106)	(63,700)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	186,371	185,777	185,183	184,589	183,995	183,401	182,807	182,213	181,619	181,025	180,431	179,837	179,243	
6	Average Net Investment		186,074	185,480	184,886	184,292	183,698	183,104	182,510	181,916	181,322	180,728	180,134	179,540	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,367	1,363	1,358	1,354	1,350	1,345	1,341	1,337	1,332	1,328	1,323	1,319	16,117
	b Debt Component (Line 6 x Debt Component x 1/12)		388	387	386	385	383	382	381	380	378	377	376	375	4,578
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)		2,349	2,343	2,339	2,333	2,328	2,322	2,316	2,310	2,304	2,300	2,293	2,288	27,823
	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	2,149	2,144	2,138	2,132	2,126	2,123	2,117	2,112	25,684
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	172	172	172	171	169	170	2,071
13	Retail Demand-Related Recoverable Costs (I)		2,090	2,085	2,082	2,077	2,072	2,067	2,061	2,056	2,050	2,047	2,041	2,036	24,764
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,265	2,260	2,256	2,251	2,246	2,240	2,233	2,228	2,222	2,218	2,210	2,206	26,835

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,920; 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 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	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		(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)	512,173	507,007	508,243	508,081	507,668	507,506	507,344	507,182	507,020	506,858	506,696	506,534	506,372	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	512,173	507,007	508,243	508,081	507,669	507,507	507,345	507,183	507,021	506,859	506,697	506,535	506,373	
6	Average Net Investment		509,590	507,625	508,162	507,875	507,588	507,426	507,264	507,102	506,940	506,778	506,616	506,454	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,744	3,730	3,733	3,731	3,729	3,728	3,727	3,726	3,724	3,723	3,722	3,721	44,738
	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	4,951	4,956	4,953	4,950	4,949	4,948	4,946	4,944	4,943	4,941	4,940	59,391
	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	4,570	4,575	4,572	4,569	4,568	4,567	4,566	4,564	4,563	4,561	4,560	54,823
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	368	367	367	367	366	366	4,413
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	4,772	4,770	4,768	4,767	4,764	4,763	57,276

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 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	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)	(136,085)	(136,899)	(137,713)	(138,527)	(139,341)	(140,155)	(140,969)	(141,783)	(142,597)	(143,411)	(144,225)	(145,039)	(145,853)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	169,238	168,424	167,610	166,796	165,982	165,168	164,354	163,540	162,726	161,912	161,098	160,284	159,470	
6	Average Net Investment		168,831	168,017	167,203	166,389	165,575	164,761	163,947	163,133	162,319	161,505	160,691	159,877	
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	1,205	1,199	1,193	1,187	1,181	1,175	14,490
	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	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)		2,406	2,399	2,391	2,383	2,376	2,368	2,361	2,353	2,346	2,338	2,330	2,323	28,374
	a Recoverable Costs Allocated to Energy		185	185	184	183	183	182	182	181	180	180	179	179	2,183
	b Recoverable Costs Allocated to Demand		2,221	2,214	2,207	2,200	2,193	2,186	2,179	2,172	2,166	2,158	2,151	2,144	26,191
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	176	175	174	174	172	172	2,108
13	Retail Demand-Related Recoverable Costs (I)		2,142	2,135	2,128	2,121	2,115	2,108	2,101	2,094	2,088	2,081	2,074	2,067	25,254
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,320	2,314	2,306	2,298	2,292	2,284	2,277	2,269	2,262	2,255	2,246	2,239	27,362

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 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	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)	(24,421)	(24,605)	(24,789)	(24,973)	(25,157)	(25,341)	(25,525)	(25,709)	(25,893)	(26,077)	(26,261)	(26,445)	(26,629)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	44,502	44,318	44,134	43,950	43,766	43,582	43,398	43,214	43,030	42,846	42,662	42,478	42,294	
6	Average Net Investment		44,410	44,226	44,042	43,858	43,674	43,490	43,306	43,122	42,938	42,754	42,570	42,386	
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	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)		603	601	600	598	596	595	592	591	589	587	586	583	7,121
	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	542	541	538	6,574
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	44	44	43	43	43	43	527
13	Retail Demand-Related Recoverable Costs (I)		537	535	534	532	530	529	526	526	525	523	522	519	6,338
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		581	579	578	577	575	574	570	570	568	566	565	562	6,865

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 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	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)	(45,174)	(45,445)	(45,716)	(45,987)	(46,258)	(46,529)	(46,800)	(47,071)	(47,342)	(47,613)	(47,884)	(48,155)	(48,426)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	56,321	56,050	55,779	55,508	55,237	54,966	54,695	54,424	54,153	53,882	53,611	53,340	53,069	
6	Average Net Investment		56,186	55,915	55,644	55,373	55,102	54,831	54,560	54,289	54,018	53,747	53,476	53,205	
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	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)		801	799	796	794	791	788	786	783	781	778	776	773	9,446
	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	735	733	730	727	726	723	721	718	716	714	8,720
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	709	707	704	701	700	697	695	692	690	688	8,408
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		773	771	768	766	763	760	758	755	753	750	748	745	9,110

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 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	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)	(26,830)	(26,989)	(27,148)	(27,307)	(27,466)	(27,625)	(27,784)	(27,943)	(28,102)	(28,261)	(28,420)	(28,579)	(28,738)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	32,713	32,554	32,395	32,236	32,077	31,918	31,759	31,600	31,441	31,282	31,123	30,964	30,805	
6	Average Net Investment		32,634	32,475	32,316	32,157	31,998	31,839	31,680	31,521	31,362	31,203	31,044	30,885	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		240	239	237	236	235	234	233	232	230	229	228	227	2,800
	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	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)		467	466	463	462	461	459	458	457	454	453	452	450	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	427	426	426	424	423	422	419	418	417	415	5,078
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	412	411	411	409	408	407	404	403	402	400	4,898
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		451	450	447	446	445	443	442	441	438	437	436	434	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 Current Period Estimated True-Up Amount
January 2008 - December 2008

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)	(48,217)	(49,198)	(50,179)	(51,160)	(52,141)	(53,122)	(54,103)	(55,084)	(56,065)	(57,046)	(58,027)	(59,008)	(59,989)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	342,902	341,921	340,940	339,959	338,978	337,997	337,016	336,035	335,054	334,073	333,092	332,111	331,130	
6	Average Net Investment		342,412	341,431	340,450	339,469	338,488	337,507	336,526	335,545	334,564	333,583	332,602	331,621	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,516	2,508	2,501	2,494	2,487	2,480	2,472	2,465	2,458	2,451	2,444	2,436	29,712
	b Debt Component (Line 6 x Debt Component x 1/12)		715	713	711	708	706	704	702	700	698	696	694	692	8,439
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)		4,212	4,202	4,193	4,183	4,174	4,165	4,155	4,146	4,137	4,128	4,119	4,109	49,923
	a Recoverable Costs Allocated to Energy		4,212	4,202	4,193	4,183	4,174	4,165	4,155	4,146	4,137	4,128	4,119	4,109	49,923
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	4,056	4,055	4,047	4,037	4,018	4,009	3,998	3,988	3,963	3,958	48,251
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	4,056	4,055	4,047	4,037	4,018	4,009	3,998	3,988	3,963	3,958	48,251

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 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	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)	(1,073,516)	(1,079,312)	(1,085,108)	(1,090,904)	(1,096,700)	(1,102,496)	(1,108,292)	(1,114,088)	(1,119,884)	(1,125,680)	(1,131,476)	(1,137,272)	(1,143,068)	
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)	1,709,084	1,703,288	1,697,492	1,691,696	1,685,900	1,680,104	1,674,308	1,668,512	1,662,716	1,656,920	1,651,124	1,645,328	1,639,532	
6	Average Net Investment		1,706,186	1,700,390	1,694,594	1,688,798	1,683,002	1,677,206	1,671,410	1,665,614	1,659,818	1,654,022	1,648,226	1,642,430	
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	5,796	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)		21,892	21,838	21,783	21,729	21,673	21,618	21,564	21,509	21,455	21,400	21,346	21,291	259,098
	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	19,754	19,704	19,653	239,167
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	1,604	1,600	1,595	1,590	1,580	1,578	19,264
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	19,047	18,999	18,950	230,609
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		21,109	21,061	21,008	20,960	20,906	20,853	20,797	20,744	20,691	20,637	20,579	20,528	249,873

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) 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 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	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)	104,474	104,101	103,728	103,355	102,982	102,609	102,236	101,863	101,490	101,117	100,744	100,371	99,998	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	283,436	283,063	282,690	282,317	281,944	281,571	281,198	280,825	280,452	280,079	279,706	279,333	278,960	
6	Average Net Investment		283,250	282,877	282,504	282,131	281,758	281,385	281,012	280,639	280,266	279,893	279,520	279,147	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,081	2,078	2,076	2,073	2,070	2,067	2,065	2,062	2,059	2,056	2,054	2,051	24,792
	b Debt Component (Line 6 x Debt Component x 1/12)		591	590	590	589	588	587	586	586	585	584	583	583	7,042
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)		3,045	3,043	3,037	3,034	3,031	3,027	3,024	3,021	3,017	3,013	3,011	3,006	36,310
	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	2,809	2,804	2,801	2,798	2,795	2,792	2,789	2,785	2,781	2,780	2,775	33,519
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	224	224	224	224	222	223	2,696
13	Retail Demand-Related Recoverable Costs (I)		2,709	2,708	2,704	2,701	2,698	2,695	2,692	2,689	2,685	2,681	2,681	2,676	32,319
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,936	2,934	2,929	2,927	2,924	2,920	2,916	2,913	2,909	2,905	2,903	2,899	35,015

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 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	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	394	0	0	3,000	4,000	0	0	
	b Clearings to Plant		0	0	0	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		835	2,423	554	0	639	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)	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	
3	Less: Accumulated Depreciation (C)	(5,896,036)	(5,947,341)	(5,997,059)	(6,048,644)	(6,100,784)	(6,152,286)	(6,204,426)	(6,256,566)	(6,308,706)	(6,360,846)	(6,412,986)	(6,465,126)	(6,517,266)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	394	394	394	3,394	7,394	7,394	7,394	
5	Net Investment (Lines 2 + 3 + 4)	10,297,757	10,246,452	10,196,734	10,145,149	10,093,009	10,041,507	9,989,761	9,937,621	9,885,481	9,836,341	9,788,201	9,736,061	9,683,921	
6	Average Net Investment		10,272,104	10,221,593	10,170,941	10,119,079	10,067,258	10,015,634	9,963,691	9,911,551	9,860,911	9,812,271	9,762,131	9,709,991	
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	73,585	73,203	72,820	72,448	72,091	71,722	71,339	880,810
	b Debt Component (Line 6 x Debt Component x 1/12)		21,438	21,332	21,227	21,119	21,010	20,903	20,794	20,685	20,580	20,478	20,374	20,265	250,205
8	Investment Expenses														
	a Depreciation (E)		41,828	41,828	41,828	41,828	41,828	41,828	41,828	41,828	41,828	41,828	41,828	41,828	501,936
	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)		178,746	178,269	177,792	177,303	176,813	176,327	175,836	175,344	174,867	174,408	173,935	173,443	2,113,083
	a Recoverable Costs Allocated to Energy		13,750	13,713	13,676	13,639	13,601	13,564	13,526	13,488	13,451	13,416	13,380	13,342	162,546
	b Recoverable Costs Allocated to Demand		164,996	164,556	164,116	163,664	163,212	162,763	162,310	161,856	161,416	160,992	160,555	160,101	1,950,537
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	13,229	13,223	13,186	13,148	13,080	13,042	12,999	12,960	12,874	12,852	157,103
13	Retail Demand-Related Recoverable Costs (I)		159,092	158,668	158,243	157,807	157,372	156,939	156,502	156,064	155,640	155,231	154,810	154,372	1,880,740
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		172,349	171,921	171,472	171,030	170,558	170,087	169,582	169,106	168,639	168,191	167,684	167,224	2,037,843

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 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	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)	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	
3	Less: Accumulated Depreciation (C)	(15,218)	(15,498)	(15,778)	(16,058)	(16,338)	(16,618)	(16,898)	(17,178)	(17,458)	(17,738)	(18,018)	(18,298)	(18,578)	
4	CWIP - Non Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	118,917	118,637	118,357	118,077	117,797	117,517	117,237	116,957	116,677	116,397	116,117	115,837	115,557	
6	Average Net Investment		118,777	118,497	118,217	117,937	117,657	117,377	117,097	116,817	116,537	116,257	115,977	115,697	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		872	870	869	867	864	862	861	858	856	855	852	850	10,336
	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	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)		1,400	1,398	1,395	1,393	1,390	1,387	1,386	1,381	1,379	1,378	1,374	1,372	16,633
	a Recoverable Costs Allocated to Energy		107	107	107	107	107	107	107	106	106	106	106	106	1,279
	b Recoverable Costs Allocated to Demand		1,293	1,291	1,288	1,286	1,283	1,280	1,279	1,275	1,273	1,272	1,268	1,266	15,354
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	103	102	102	102	102	102	1,235
13	Retail Demand-Related Recoverable Costs (I)		1,247	1,245	1,242	1,240	1,237	1,234	1,233	1,229	1,227	1,226	1,223	1,221	14,804
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,350	1,348	1,346	1,344	1,341	1,338	1,336	1,331	1,329	1,328	1,325	1,323	16,039

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 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	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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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 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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		15,772	686,333	2,518	(426)	581	4,004	0	0	395,778	492,495	0	0	
	b Clearings to Plant		15,772	1,150	61	0	0	0	0	0	0	83,017	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	134,527,864	134,527,864	134,527,864	
3	Less: Accumulated Depreciation (C)	(12,843,242)	(13,232,240)	(13,621,261)	(14,010,284)	(14,399,307)	(14,788,330)	(15,177,353)	(15,566,376)	(15,955,399)	(16,344,422)	(16,733,555)	(17,122,799)	(17,512,043)	
4	CWIP - Non Interest Bearing	(0)	(0)	685,182	687,639	687,213	687,794	691,799	691,799	691,799	1,087,577	1,497,055	1,497,055	1,497,055	
5	Net Investment (Lines 2 + 3 + 4)	121,584,622	121,211,395	121,508,707	121,122,201	120,732,752	120,344,311	119,959,292	119,570,269	119,181,246	119,188,001	119,291,363	118,902,119	118,512,875	
6	Average Net Investment		121,398,008	121,360,051	121,315,454	120,927,477	120,538,531	120,151,801	119,764,781	119,375,758	119,184,624	119,239,682	119,096,741	118,707,497	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		891,911	891,632	891,305	888,454	885,597	882,755	879,912	877,054	875,649	876,054	875,004	872,144	10,587,471
	b Debt Component (Line 6 x Debt Component x 1/12)		253,358	253,278	253,185	252,376	251,564	250,757	249,949	249,137	248,738	248,853	248,555	247,743	3,007,493
8	Investment Expenses														
	a Depreciation (E)		358,026	358,049	358,051	358,051	358,051	358,051	358,051	358,051	358,051	358,161	358,272	358,272	4,297,137
	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)		1,534,267	1,533,931	1,533,513	1,529,853	1,526,184	1,522,535	1,518,884	1,515,214	1,513,410	1,514,040	1,512,803	1,509,131	18,263,765
	a Recoverable Costs Allocated to Energy		1,534,267	1,533,931	1,533,513	1,529,853	1,526,184	1,522,535	1,518,884	1,515,214	1,513,410	1,514,040	1,512,803	1,509,131	18,263,765
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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)		1,479,280	1,482,516	1,483,360	1,483,135	1,479,583	1,475,865	1,468,775	1,465,125	1,462,526	1,462,553	1,455,617	1,453,740	17,652,075
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)		1,479,280	1,482,516	1,483,360	1,483,135	1,479,583	1,475,865	1,468,775	1,465,125	1,462,526	1,462,553	1,455,617	1,453,740	17,652,075

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 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	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)	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	
3	Less: Accumulated Depreciation (C)	(30,628)	(33,081)	(35,534)	(37,987)	(40,440)	(42,893)	(45,346)	(47,799)	(50,252)	(52,705)	(55,158)	(57,611)	(60,064)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	889,209	886,756	884,303	881,850	879,397	876,944	874,491	872,038	869,585	867,132	864,679	862,226	859,773	
6	Average Net Investment		887,983	885,530	883,077	880,624	878,171	875,718	873,265	870,812	868,359	865,906	863,453	861,000	
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	1,823	1,817	1,812	1,807	1,802	1,797	21,901
8	Investment Expenses														
	a Depreciation (E)		2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	29,436
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,830	10,807	10,784	10,761	10,738	10,715	10,692	10,668	10,645	10,622	10,599	10,576	128,437
	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	9,933	9,912	9,891	9,870	9,847	9,826	9,805	9,784	9,762	118,557
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	795	794	791	789	784	784	9,549
13	Retail Demand-Related Recoverable Costs (I)		9,639	9,619	9,598	9,578	9,557	9,537	9,517	9,495	9,474	9,454	9,434	9,413	114,315
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,442	10,422	10,401	10,381	10,358	10,336	10,312	10,289	10,265	10,243	10,218	10,197	123,864

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 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	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)	(7,897)	(8,065)	(8,233)	(8,401)	(8,569)	(8,737)	(8,905)	(9,073)	(9,241)	(9,409)	(9,577)	(9,745)	(9,913)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	54,973	54,805	54,637	54,469	54,301	54,133	53,965	53,797	53,629	53,461	53,293	53,125	52,957	
6	Average Net Investment		54,889	54,721	54,553	54,385	54,217	54,049	53,881	53,713	53,545	53,377	53,209	53,041	
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	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)		686	684	683	682	679	678	676	675	673	671	670	669	8,126
	a Recoverable Costs Allocated to Energy		686	684	683	682	679	678	676	675	673	671	670	669	8,126
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	661	661	658	657	654	653	650	648	645	644	7,853
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	661	661	658	657	654	653	650	648	645	644	7,853

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 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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		2,535,141	2,977,154	2,109,373	1,109,428	336,771	63,962	60,000	0	0	0	0	0	
	b Clearings to Plant		18,648	(11,425)	12,355,971	1,109,428	336,771	63,962	60,000	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	15,832,691	15,851,339	15,839,914	28,195,884	29,305,312	29,642,083	29,706,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	
3	Less: Accumulated Depreciation (C)	(701,455)	(734,633)	(767,823)	(817,470)	(885,074)	(954,606)	(1,024,672)	(1,094,904)	(1,165,216)	(1,235,528)	(1,305,840)	(1,376,152)	(1,446,464)	
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)	19,872,761	22,374,724	25,318,688	27,378,414	28,420,238	28,687,476	28,681,373	28,671,141	28,600,829	28,530,517	28,460,205	28,389,893	28,319,581	
6	Average Net Investment		21,123,742	23,846,706	26,348,551	27,899,326	28,553,857	28,684,424	28,676,257	28,635,985	28,565,673	28,495,361	28,425,049	28,354,737	
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	209,785	210,744	210,684	210,389	209,872	209,355	208,839	208,322	2,406,947
	b Debt Component (Line 6 x Debt Component x 1/12)		44,085	49,768	54,989	58,226	59,592	59,864	59,847	59,763	59,617	59,470	59,323	59,176	683,720
8	Investment Expenses														
	a Depreciation (E)		33,178	33,190	49,647	67,604	69,532	70,066	70,232	70,312	70,312	70,312	70,312	70,312	745,009
	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)		232,459	258,160	298,219	330,806	338,909	340,674	340,763	340,464	339,801	339,137	338,474	337,810	3,835,676
	a Recoverable Costs Allocated to Energy		232,459	258,160	298,219	330,806	338,909	340,674	340,763	340,464	339,801	339,137	338,474	337,810	3,835,676
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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)		224,128	249,507	288,466	320,704	328,561	330,231	329,521	329,209	328,376	327,604	325,679	325,411	3,707,397
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)		224,128	249,507	288,466	320,704	328,561	330,231	329,521	329,209	328,376	327,604	325,679	325,411	3,707,397

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Smith $15,715,201; Scholz $117,490. Ending Balances: Crist, $13,925,707; Smith $15,715,201; Scholz $125,137.
(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 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	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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E. 1227
(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)	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	0	
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	87,587	
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	87,712	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		665	663	661	659	657	655	654	652	650	648	646	644	7,854
	b Debt Component (Line 6 x Debt Component x 1/12)		189	188	188	187	187	186	186	185	185	184	184	183	2,232
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	1,077	13,086
	a Recoverable Costs Allocated to Energy		85	85	85	84	84	84	84	84	83	83	83	83	1,007
	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	994	12,079
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	81	81	80	80	80	80	971
13	Retail Demand-Related Recoverable Costs (I)		983	980	978	976	974	971	970	967	966	963	961	958	11,647
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,065	1,062	1,060	1,057	1,055	1,052	1,051	1,048	1,046	1,043	1,041	1,038	12,618

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 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	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	14,165	85,835	25,000	0	25,000	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	150,000	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)	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,977,707	5,977,707	5,977,707	
3	Less: Accumulated Depreciation (C)	(310,341)	(325,883)	(341,425)	(356,967)	(372,509)	(388,051)	(403,593)	(419,135)	(434,677)	(450,219)	(465,961)	(481,903)	(497,845)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	14,165	100,000	125,000	125,000	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,517,366	5,501,824	5,486,282	5,470,740	5,455,198	5,439,656	5,438,279	5,508,572	5,518,030	5,502,488	5,511,746	5,495,804	5,479,862	
6	Average Net Investment		5,509,595	5,494,053	5,478,511	5,462,969	5,447,427	5,438,968	5,473,426	5,513,301	5,510,259	5,507,117	5,503,775	5,487,833	
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	40,213	40,506	40,484	40,461	40,436	40,319	483,632
	b Debt Component (Line 6 x Debt Component x 1/12)		11,499	11,466	11,434	11,401	11,369	11,351	11,423	11,506	11,500	11,493	11,486	11,453	137,381
8	Investment Expenses														
	a Depreciation (E)		15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,742	15,942	15,942	187,504
	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)		67,520	67,373	67,227	67,079	66,933	66,853	67,178	67,554	67,526	67,696	67,864	67,714	808,517
	a Recoverable Costs Allocated to Energy		5,194	5,183	5,171	5,160	5,149	5,143	5,168	5,196	5,194	5,207	5,220	5,209	62,194
	b Recoverable Costs Allocated to Demand		62,326	62,190	62,056	61,919	61,784	61,710	62,010	62,358	62,332	62,489	62,644	62,505	746,323
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	4,985	4,998	5,024	5,019	5,030	5,023	5,018	60,110
13	Retail Demand-Related Recoverable Costs (I)		60,096	59,965	59,835	59,703	59,573	59,502	59,791	60,127	60,102	60,253	60,402	60,268	719,617
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		65,104	64,974	64,837	64,705	64,565	64,487	64,789	65,151	65,121	65,283	65,425	65,286	779,727

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 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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		830,024	331,655	719,568	16,357,754	3,012,664	3,258,229	4,126,416	1,390,534	1,765,913	1,313,238	1,909,821	2,298,760	
	b Clearings to Plant		40,900	285,641	86,163	15,188,344	2,209,064	612,699	0	0	2,870,114	3,802,878	0	10,276,277	
	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)	29,838,819	29,879,720	30,165,360	30,251,523	45,439,866	47,648,931	48,261,630	48,261,630	48,261,630	51,131,744	54,934,622	54,934,622	65,210,899	
3	Less: Accumulated Depreciation (C)	(487,157)	(566,024)	(645,305)	(725,185)	(825,569)	(949,152)	(1,076,498)	(1,204,661)	(1,332,824)	(1,464,441)	(1,603,474)	(1,746,467)	(1,901,501)	
4	CWIP - Non Interest Bearing	688,521	1,477,645	1,523,659	2,157,065	3,326,475	4,130,075	6,775,604	10,902,020	12,292,554	11,188,353	8,698,713	10,608,533	2,631,016	
5	Net Investment (Lines 2 + 3 + 4)	30,040,184	30,791,340	31,043,714	31,683,402	47,940,773	50,829,854	53,960,737	57,958,989	59,221,360	60,855,656	62,029,861	63,796,689	65,940,414	
6	Average Net Investment		30,415,762	30,917,527	31,363,558	39,812,087	49,385,313	52,395,295	55,959,863	58,590,174	60,038,508	61,442,758	62,913,275	64,868,551	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		223,465	227,151	230,428	292,499	362,834	384,948	411,137	430,462	441,103	451,420	462,224	476,589	4,394,260
	b Debt Component (Line 6 x Debt Component x 1/12)		63,478	64,525	65,456	83,088	103,067	109,349	116,788	122,278	125,300	128,231	131,300	135,381	1,248,241
8	Investment Expenses														
	a Depreciation (E)		78,409	78,823	79,422	99,926	123,125	126,888	127,705	127,705	131,159	138,575	142,535	154,576	1,408,848
	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)		365,810	370,957	375,764	475,971	589,484	621,643	656,088	680,903	698,020	718,684	736,517	767,004	7,056,845
	a Recoverable Costs Allocated to Energy		365,810	370,957	375,764	475,971	589,484	621,643	656,088	680,903	698,020	718,684	736,517	767,004	7,056,845
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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)		352,700	358,523	363,475	461,436	571,485	602,588	634,443	658,394	674,551	694,244	708,675	738,852	6,819,366
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)		352,700	358,523	363,475	461,436	571,485	602,588	634,443	658,394	674,551	694,244	708,675	738,852	6,819,366

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 $49,165,896; Smith $11,368,753, Daniel $4,020,088, Scholz $656,162.
(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 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	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)	0	(394)	(788)	(1,182)	(1,576)	(1,970)	(2,364)	(2,758)	(3,152)	(3,546)	(3,940)	(4,334)	(4,728)	
4	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	22,078	21,684	21,290	20,896	20,502	20,108	19,714	19,320	18,926	
6	Average Net Investment		23,457	23,063	22,669	22,275	21,881	21,487	21,093	20,699	20,305	19,911	19,517	19,123	
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	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)		615	611	608	604	601	597	593	589	585	582	578	574	7,137
	a Recoverable Costs Allocated to Energy		615	611	608	604	601	597	593	589	585	582	578	574	7,137
	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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)		593	591	588	586	583	579	573	570	565	562	556	553	6,899
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)		593	591	588	586	583	579	573	570	565	562	556	553	6,899

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 2008 - December 2008

Return on Working Capital, SO2 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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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 2008 - December 2008

Return on Working Capital, SO2 Expenses
For Project: Annual Nox Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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 2008 - December 2008

Return on Working Capital, SO2 Expenses
For Project: Seasonal Nox Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	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	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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 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	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	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	10,383,355	9,637,660	8,929,523	8,226,194	7,630,066	7,123,759	
	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	9,083,790	8,387,171	7,728,111	7,073,859	6,526,808	6,069,579	
4	Average Net Working Capital Balance		13,052,097	12,514,974	12,010,157	11,505,774	10,812,522	10,098,138	9,453,001	8,735,481	8,057,641	7,400,985	6,800,334	6,298,193	
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	69,451	64,180	59,199	54,375	49,962	46,273	857,685
	b Debt Component (Line 4 x Debt Component x 1/12)		27,240	26,119	25,065	24,013	22,566	21,075	19,728	18,231	16,816	15,446	14,192	13,144	243,635
6	Total Return Component (D)		123,134	118,067	113,304	108,546	102,006	95,266	89,179	82,411	76,015	69,821	64,154	59,417	1,101,320
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	0
	c SO2 Allowance Expense		572,013	518,675	507,400	517,808	497,403	632,807	746,941	745,695	708,137	703,329	596,128	506,306	7,252,642
8	Net Expenses (E)		563,792	510,454	499,179	509,587	449,566	590,490	697,864	696,618	659,060	654,252	547,051	457,229	6,835,142
9	Total System Recoverable Expenses (Lines 6 + 8)		686,926	628,521	612,483	618,133	551,572	685,756	787,043	779,029	735,075	724,073	611,205	516,646	7,936,462
	a Recoverable Costs Allocated to Energy		686,926	628,521	612,483	618,133	551,572	685,756	787,043	779,029	735,075	724,073	611,205	516,646	7,936,462
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9663327	0.9662664	0.9657017	0.9653179	0.9615253	0.9626224	
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	761,077	753,277	710,360	699,450	588,101	497,683	7,670,883
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	761,077	753,277	710,360	699,450	588,101	497,683	7,670,883

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

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2009 - December 2009

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)	38,347,456	2,668,005	41,015,461
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	40,547,658	3,198,466	43,746,124
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	78,895,114	5,866,471	84,761,585
2	True-Up for Estimated Over/(Under) Recovery for the period January 2008 - December 2008 (Schedule 1E, Line 3)	(2,508,465)	(301,825)	(2,810,290)
3	Final True-Up for the period January 2007 - December 2007 (Schedule 1A, Line 3)	1,295,632	174,839	1,470,471
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2009 - December 2009 (Line 1c - Line 2 - Line 3)	80,107,947	5,993,457	86,101,404
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	80,165,625	5,997,772	86,163,397

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.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080007-EI EXHIBIT 27
COMPANY Gulf Power Co. (Direct)
WITNESS Susan Ritenour (SDR-3)
DATE 11-04-08

Docket No. 080007-EI
2009 Projection Filing
Exhibit SDR-3, Page 1 of 87

Gulf Power Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2009 - December 2009

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	840,000	0	0	0	0	0	0	124,374	0	0	0	964,374	0	964,374
	.3 Title V	12,934	8,968	10,615	9,817	9,817	12,027	13,893	9,810	11,250	9,815	9,205	11,202	129,352	0	129,352
	.4 Asbestos Fees	1,500	0	0	0	0	0	0	0	0	0	0	1,000	2,500	2,500	0
	.5 Emission Monitoring	56,960	50,400	57,806	48,102	58,291	59,181	60,734	48,117	60,570	49,248	46,469	60,330	656,209	0	656,209
	.6 General Water Quality	49,150	45,965	51,294	44,332	31,738	38,388	36,985	58,244	61,363	51,121	50,821	36,677	556,074	556,074	0
	.7 Groundwater Contamination Investigation	115,380	100,723	105,089	273,280	273,280	109,185	121,162	105,752	108,204	107,319	106,488	105,311	1,631,176	1,631,176	0
	.8 State NPDES Administration	23,000	0	0	0	0	0	0	0	0	0	7,500	11,500	42,000	42,000	0
	.9 Lead and Copper Rule	4,100	0	4,300	0	0	4,000	0	0	4,000	0	4,000	0	20,400	20,400	0
	.10 Env Auditing/Assessment	0	0	3,000	0	0	1,500	1,500	0	650	0	0	650	7,300	7,300	0
	.11 General Solid & Hazardous Waste	39,271	32,072	34,007	32,691	32,691	35,691	41,653	32,691	35,421	33,421	33,421	34,439	417,471	417,471	0
	.12 Above Ground Storage Tanks	2,053	1,976	20,486	2,936	5,446	1,979	26,944	1,923	1,970	1,933	20,414	2,040	90,100	90,100	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	230,000	340,000	230,000	0	0	0	0	0	0	0	800,000	0	800,000
	.15 Mercury Emissions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.16 Sodium Injection	25,800	26,650	25,800	24,950	25,800	26,650	27,500	24,950	27,500	25,800	24,100	27,500	313,000	0	313,000
	.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	258,754	315,475	227,872	345,454	814,829	350,486	376,619	323,058	325,935	261,959	242,443	325,779	4,168,665	0	4,168,665
	.20 CAIR/CAMR/CAVR Compliance Program	561,679	547,059	526,558	432,926	454,146	481,366	509,533	443,965	507,688	508,248	422,816	576,542	5,972,528	0	5,972,528
	.21 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.22 Annual NOx Allowances	0	0	0	0	0	645,556	2,394,454	3,249,899	3,255,805	2,651,941	2,659,092	3,779,038	18,635,785	0	18,635,785
	.23 Seasonal NOx Allowances	0	0	0	0	413,885	431,894	461,802	462,602	384,807	0	0	0	2,154,990	0	2,154,990
	.24 SO_2 Allowances	281,286	305,436	273,252	347,607	354,206	361,944	906,735	909,355	761,194	540,093	453,704	417,961	5,912,773	0	5,912,773
2	Total of O & M Activities	1,431,867	2,274,724	1,570,079	1,902,096	2,704,130	2,559,848	4,979,513	5,670,366	5,670,732	4,240,899	4,080,474	5,389,970	42,474,697	2,767,020	39,707,676
3	Recoverable Costs Allocated to Energy	1,197,413	2,093,988	1,351,904	1,548,857	2,360,975	2,369,105	4,751,269	5,471,756	5,459,123	4,047,105	3,857,830	5,198,352	39,707,676		
4	Recoverable Costs Allocated to Demand	234,454	180,736	218,175	353,239	343,155	190,743	228,244	198,610	211,608	193,794	222,644	191,617	2,767,020		
5	Retail Energy Jurisdictional Factor	0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706			
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)	1,153,309	2,020,984	1,304,179	1,497,161	2,283,393	2,291,082	4,595,420	5,292,102	5,275,720	3,907,520	3,716,701	5,009,885	38,347,456		
8	Jurisdictional Demand Recoverable Costs (B)	226,064	174,269	210,368	340,599	330,876	183,918	220,076	191,503	204,036	186,859	214,677	184,760	2,668,005		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,379,373	2,195,253	1,514,547	1,837,760	2,614,269	2,475,000	4,815,496	5,483,605	5,479,756	4,094,379	3,931,378	5,194,645	41,015,461		27,355,861

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 2009 - December 2009

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	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	164,874	164,389	163,904	163,418	162,933	162,447	161,961	161,475	160,990	160,505	160,019	159,534	1,946,449	0	1,946,449
	.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, and Daniel	72,640	72,516	72,391	72,268	72,143	72,019	71,895	71,771	71,646	72,509	74,887	76,386	873,071	0	873,071
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	8,589	8,571	8,554	8,536	8,519	8,502	8,485	8,467	8,450	8,432	8,416	8,398	101,919	94,079	7,840
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,282	2,276	2,271	2,266	2,260	2,254	2,249	2,243	2,238	2,231	2,226	2,221	27,017	24,938	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	445	444	443	441	440	439	436	435	434	432	5,286	4,880	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	20,690	20,635	251,224	231,899	19,325
	.15 Smith Waste Water Treatment Facility	3,003	2,999	2,996	2,992	2,989	2,985	2,982	2,978	2,975	2,971	2,968	2,964	35,802	33,048	2,754
	.16 Daniel Ash Management Project	171,160	172,089	174,454	175,412	174,949	174,485	174,022	173,558	173,096	172,632	172,169	171,705	2,079,731	1,919,755	159,976
	.17 Smith Water Conservation	1,369	1,366	1,364	1,361	1,359	1,356	1,353	1,351	1,348	1,345	1,342	1,339	16,253	15,003	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	1,505,458	1,501,786	1,504,541	1,507,280	1,503,577	1,499,875	1,496,172	1,492,469	1,488,766	1,485,063	1,481,361	1,477,658	17,944,006	0	17,944,006
	.20 SPCC Compliance	10,576	10,624	10,721	10,771	10,747	10,723	10,700	10,676	10,652	10,629	10,605	10,582	128,006	118,158	9,848
	.21 Crist Common FTIR Monitor	666	665	664	662	661	659	657	656	655	652	651	649	7,897	0	7,897
	.22 Precipitator Upgrades for CAM Compliance	337,148	336,484	335,821	335,157	334,494	333,831	333,167	332,504	331,841	331,177	330,514	329,850	4,001,988	0	4,001,988
	.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	3,325	5,585	5,572	5,561	11,019	38,538	35,571	2,967
	.25 Plant NPDES Permit Compliance Projects	67,564	67,414	67,263	67,113	66,962	66,811	66,661	66,511	66,361	66,210	66,060	65,910	800,840	739,236	61,604
	.26 CAIR/CAMR/CAVR Compliance Program	816,272	844,550	860,947	873,262	871,468	869,675	867,881	866,088	864,294	862,501	860,707	3,955,676	13,413,321	0	13,413,321
	.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	0	0	0	7,548	30,988	45,198	38,549	28,591	21,453	17,131	7,490	196,948	0	196,948
	.30 Seasonal Nox Allowances	10,165	20,330	20,330	20,330	18,378	14,388	10,172	5,813	1,816	0	0	0	121,722	0	121,722
	.31 SO2 Allowances	55,934	53,166	50,437	47,508	44,197	82,479	118,156	109,589	101,709	95,571	90,883	86,772	936,401	0	936,401
2	Total Investment Projects - Recoverable Costs	3,451,021	3,482,206	3,499,293	3,510,635	3,505,140	3,555,091	3,592,987	3,567,900	3,540,551	3,518,653	3,504,364	6,586,677	45,314,518	3,317,168	41,997,350
3	Recoverable Costs Allocated to Energy	3,177,348	3,207,865	3,222,918	3,233,564	3,228,754	3,279,392	3,317,970	3,291,480	3,262,727	3,241,524	3,227,924	6,305,884	41,997,350		
4	Recoverable Costs Allocated to Demand	273,673	274,341	276,375	277,071	276,387	275,700	275,017	276,422	277,823	277,129	276,439	280,791	3,317,168		
5	Retail Energy Jurisdictional Factor	0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706			
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)	3,060,318	3,096,026	3,109,143	3,125,639	3,122,657	3,171,391	3,209,135	3,183,411	3,153,113	3,129,723	3,109,839	6,077,263	40,547,658		
8	Jurisdictional Demand Recoverable Costs (C)	263,880	264,524	266,485	267,156	266,497	265,834	265,176	266,531	267,881	267,212	266,547	270,743	3,198,466		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	3,324,198	3,360,550	3,375,628	3,392,795	3,389,154	3,437,225	3,474,311	3,449,942	3,420,994	3,396,935	3,376,386	6,348,006	43,746,124		

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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(104,690)	(107,313)	(109,936)	(112,559)	(115,182)	(117,805)	(120,428)	(123,051)	(125,674)	(128,297)	(130,920)	(133,543)	(136,166)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	115,604	112,981	110,358	107,735	105,112	102,489	99,866	97,243	94,620	91,997	89,374	86,751	84,128	
6	Average Net Investment		114,293	111,670	109,047	106,424	103,801	101,178	98,555	95,932	93,309	90,686	88,063	85,440	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		3,566	3,548	3,523	3,506	3,485	3,459	3,436	3,412	3,386	3,358	3,328	3,305	41,312
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)		3,566	3,548	3,523	3,506	3,485	3,459	3,436	3,412	3,386	3,358	3,328	3,305	41,312

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	15,031,878	
3	Less: Accumulated Depreciation (C)	(2,984,897)	(3,036,363)	(3,087,829)	(3,139,295)	(3,190,761)	(3,242,227)	(3,293,693)	(3,345,159)	(3,396,625)	(3,448,091)	(3,499,557)	(3,551,023)	(3,602,489)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	12,046,981	11,995,515	11,944,049	11,892,583	11,841,117	11,789,651	11,738,185	11,686,719	11,635,253	11,583,787	11,532,321	11,480,855	11,429,389	
6	Average Net Investment		12,021,248	11,969,782	11,918,316	11,866,850	11,815,384	11,763,918	11,712,452	11,660,986	11,609,520	11,558,054	11,506,588	11,455,122	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		88,320	87,942	87,564	87,186	86,808	86,430	86,051	85,673	85,295	84,917	84,539	84,161	1,034,886
	b Debt Component (Line 6 x Debt Component x 1/12)		25,088	24,981	24,874	24,766	24,659	24,551	24,444	24,336	24,229	24,122	24,014	23,907	293,971
8	Investment Expenses														
	a Depreciation (E)		40,091	40,091	40,091	40,091	40,091	40,091	40,091	40,091	40,091	40,091	40,091	40,091	481,092
	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)		164,874	164,389	163,904	163,418	162,933	162,447	161,961	161,475	160,990	160,505	160,019	159,534	1,946,449
	a Recoverable Costs Allocated to Energy		164,874	164,389	163,904	163,418	162,933	162,447	161,961	161,475	160,990	160,505	160,019	159,534	1,946,449
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		158,801	158,658	158,118	157,964	157,579	157,097	156,648	156,173	155,581	154,969	154,165	153,750	1,879,503
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)		158,801	158,658	158,118	157,964	157,579	157,097	156,648	156,173	155,581	154,969	154,165	153,750	1,879,503

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 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	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)	1,467,263	1,467,059	1,466,855	1,466,651	1,466,447	1,466,243	1,466,039	1,465,835	1,465,631	1,465,427	1,465,223	1,465,019	1,464,815	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,467,263	1,467,059	1,466,855	1,466,651	1,466,447	1,466,243	1,466,039	1,465,835	1,465,631	1,465,427	1,465,223	1,465,019	1,464,815	
6	Average Net Investment		1,467,161	1,466,957	1,466,753	1,466,549	1,466,345	1,466,141	1,465,937	1,465,733	1,465,529	1,465,325	1,465,121	1,464,917	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		13,528	13,554	13,545	13,571	13,576	13,574	13,573	13,571	13,559	13,544	13,513	13,516	162,624
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)		13,528	13,554	13,545	13,571	13,576	13,574	13,573	13,571	13,559	13,544	13,513	13,516	162,624

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 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	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)	6,312,951	6,288,687	6,264,423	6,240,159	6,215,895	6,191,631	6,167,367	6,143,103	6,118,839	6,094,575	6,070,311	6,046,047	6,021,783	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	15,410,874	15,386,610	15,362,346	15,338,082	15,313,818	15,289,554	15,265,290	15,241,026	15,216,762	15,192,498	15,168,234	15,143,970	15,119,706	
6	Average Net Investment		15,398,742	15,374,478	15,350,214	15,325,950	15,301,686	15,277,422	15,253,158	15,228,894	15,204,630	15,180,366	15,156,102	15,131,838	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		163,292	163,404	163,109	163,213	163,079	162,845	162,646	162,420	162,070	161,699	161,129	160,963	1,949,869
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)		163,292	163,404	163,109	163,213	163,079	162,845	162,646	162,420	162,070	161,699	161,129	160,963	1,949,869

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 2009 - December 2009

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	209,081	209,081	21,668	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	400,032	65,000	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	59,100	
	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)	4,816,670	4,816,670	4,816,670	4,816,670	4,816,670	4,816,670	4,816,670	4,816,670	4,816,670	4,816,670	4,816,670	5,216,702	5,222,602	
3	Less: Accumulated Depreciation (C)	1,321,489	1,308,327	1,295,165	1,282,003	1,268,841	1,255,679	1,242,517	1,229,355	1,216,193	1,203,031	1,189,869	1,176,174	1,221,037	
4	CWIP - Non Interest Bearing	25,202	25,202	25,202	25,202	25,202	25,202	25,202	25,202	25,202	25,202	234,283	43,332	(0)	
5	Net Investment (Lines 2 + 3 + 4)	6,163,361	6,150,199	6,137,037	6,123,875	6,110,713	6,097,551	6,084,389	6,071,227	6,058,065	6,044,903	6,240,822	6,436,208	6,443,639	
6	Average Net Investment		6,156,780	6,143,618	6,130,456	6,117,294	6,104,132	6,090,970	6,077,808	6,064,646	6,051,484	6,142,862	6,338,515	6,439,923	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		45,234	45,137	45,040	44,944	44,847	44,750	44,654	44,557	44,460	45,132	46,569	47,314	542,638
	b Debt Component (Line 6 x Debt Component x 1/12)		12,849	12,822	12,794	12,767	12,739	12,712	12,684	12,657	12,629	12,820	13,228	13,440	154,141
8	Investment Expenses														
	a Depreciation (E)		13,030	13,030	13,030	13,030	13,030	13,030	13,030	13,030	13,030	13,030	13,563	14,105	157,968
	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		1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	16,740
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		72,640	72,516	72,391	72,268	72,143	72,019	71,895	71,771	71,646	72,509	74,887	76,386	873,071
	a Recoverable Costs Allocated to Energy		72,640	72,516	72,391	72,268	72,143	72,019	71,895	71,771	71,646	72,509	74,887	76,386	873,071
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		69,964	69,988	69,835	69,856	69,772	69,647	69,537	69,415	69,239	70,008	72,147	73,617	843,025
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)		69,964	69,988	69,835	69,856	69,772	69,647	69,537	69,415	69,239	70,008	72,147	73,617	843,025

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,232,602; Scholz $987,947; Smith $943,402; Daniel $652,719. Ending Balances: Crist, $2,638,534; Scholz $987,947; Smith $943,402; Daniel $652,719.
(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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(201,333)	(203,169)	(205,005)	(206,841)	(208,677)	(210,513)	(212,349)	(214,185)	(216,021)	(217,857)	(219,693)	(221,529)	(223,365)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	716,691	714,855	713,019	711,183	709,347	707,511	705,675	703,839	702,003	700,167	698,331	696,495	694,659	
6	Average Net Investment		715,773	713,937	712,101	710,265	708,429	706,593	704,757	702,921	701,085	699,249	697,413	695,577	
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	1,456	1,452	17,673
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)		8,589	8,571	8,554	8,536	8,519	8,502	8,485	8,467	8,450	8,432	8,416	8,398	101,919
	a Recoverable Costs Allocated to Energy		661	659	658	657	655	654	653	651	650	649	647	646	7,840
	b Recoverable Costs Allocated to Demand		7,928	7,912	7,896	7,879	7,864	7,848	7,832	7,816	7,800	7,783	7,769	7,752	94,079
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	635	633	632	632	630	628	627	623	623	7,571
13	Retail Demand-Related Recoverable Costs (I)		7,644	7,629	7,613	7,597	7,583	7,567	7,552	7,536	7,521	7,504	7,491	7,475	90,712
14	Total Juris. Recoverable Costs (Lines 12 + 13)		8,281	8,265	8,248	8,232	8,216	8,199	8,184	8,166	8,149	8,131	8,114	8,098	98,283

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	242,943	
3	Less: Accumulated Depreciation (C)	(63,700)	(64,294)	(64,888)	(65,482)	(66,076)	(66,670)	(67,264)	(67,858)	(68,452)	(69,046)	(69,640)	(70,234)	(70,828)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	179,243	178,649	178,055	177,461	176,867	176,273	175,679	175,085	174,491	173,897	173,303	172,709	172,115	
6	Average Net Investment		178,946	178,352	177,758	177,164	176,570	175,976	175,382	174,788	174,194	173,600	173,006	172,412	
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	1,297	1,293	1,289	1,284	1,280	1,275	1,271	1,267	15,489
	b Debt Component (Line 6 x Debt Component x 1/12)		373	372	371	370	369	367	366	365	364	362	361	360	4,400
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)		2,282	2,276	2,271	2,266	2,260	2,254	2,249	2,243	2,238	2,231	2,226	2,221	27,017
	a Recoverable Costs Allocated to Energy		176	175	175	174	174	173	173	173	172	172	171	171	2,079
	b Recoverable Costs Allocated to Demand		2,106	2,101	2,096	2,092	2,086	2,081	2,076	2,070	2,066	2,059	2,055	2,050	24,938
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		170	169	169	168	168	167	167	167	166	166	165	165	2,007
13	Retail Demand-Related Recoverable Costs (I)		2,031	2,026	2,021	2,017	2,011	2,007	2,002	1,996	1,992	1,985	1,981	1,977	24,046
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,201	2,195	2,190	2,185	2,179	2,174	2,169	2,163	2,158	2,151	2,146	2,142	26,053

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,920 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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	506,372	506,210	506,048	505,886	505,724	505,562	505,400	505,238	505,076	504,914	504,752	504,590	504,428	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	506,372	506,210	506,048	505,886	505,724	505,562	505,400	505,238	505,076	504,914	504,752	504,590	504,428	
6	Average Net Investment		506,291	506,129	505,967	505,805	505,643	505,481	505,319	505,157	504,995	504,833	504,671	504,509	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	367	367	367	367	367	366	366	365	365	4,397
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 Juris. Recoverable Costs (Lines 12 + 13)		4,762	4,761	4,759	4,758	4,757	4,756	4,755	4,752	4,750	4,749	4,746	4,745	57,050

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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2009 Projection Filing
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(145,853)	(146,667)	(147,481)	(148,295)	(149,109)	(149,923)	(150,737)	(151,551)	(152,365)	(153,179)	(153,993)	(154,807)	(155,621)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	159,470	158,656	157,842	157,028	156,214	155,400	154,586	153,772	152,958	152,144	151,330	150,516	149,702	
6	Average Net Investment		159,063	158,249	157,435	156,621	155,807	154,993	154,179	153,365	152,551	151,737	150,923	150,109	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		171	171	171	170	170	169	169	168	167	167	166	166	2,025
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 Juris. Recoverable Costs (Lines 12 + 13)		2,232	2,225	2,218	2,210	2,203	2,195	2,188	2,180	2,173	2,166	2,158	2,150	26,298

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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2009 Projection Filing
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(26,629)	(26,813)	(26,997)	(27,181)	(27,365)	(27,549)	(27,733)	(27,917)	(28,101)	(28,285)	(28,469)	(28,653)	(28,837)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	42,294	42,110	41,926	41,742	41,558	41,374	41,190	41,006	40,822	40,638	40,454	40,270	40,086	
6	Average Net Investment		42,202	42,018	41,834	41,650	41,466	41,282	41,098	40,914	40,730	40,546	40,362	40,178	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	42	43	43	43	43	43	43	42	41	41	510
13	Retail Demand-Related Recoverable Costs (I)		518	517	515	514	513	510	509	507	505	504	503	501	6,116
14	Total Juris. Recoverable Costs (Lines 12 + 13)		561	560	557	557	556	553	552	550	548	546	544	542	6,626

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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2009 Projection Filing
Exhibit SDR-3, Page 13 of 87

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(48,426)	(48,697)	(48,968)	(49,239)	(49,510)	(49,781)	(50,052)	(50,323)	(50,594)	(50,865)	(51,136)	(51,407)	(51,678)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	53,069	52,798	52,527	52,256	51,985	51,714	51,443	51,172	50,901	50,630	50,359	50,088	49,817	
6	Average Net Investment		52,934	52,663	52,392	52,121	51,850	51,579	51,308	51,037	50,766	50,495	50,224	49,953	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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 Juris. 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

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2009 Projection Filing
Exhibit SDR-3, Page 14 of 87

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(28,738)	(28,897)	(29,056)	(29,215)	(29,374)	(29,533)	(29,692)	(29,851)	(30,010)	(30,169)	(30,328)	(30,487)	(30,646)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	30,805	30,646	30,487	30,328	30,169	30,010	29,851	29,692	29,533	29,374	29,215	29,056	28,897	
6	Average Net Investment		30,726	30,567	30,408	30,249	30,090	29,931	29,772	29,613	29,454	29,295	29,136	28,977	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		226	225	223	222	221	220	219	218	216	215	214	213	2,632
	b Debt Component (Line 6 x Debt Component x 1/12)		64	64	63	63	63	62	62	62	61	61	61	60	746
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	445	444	443	441	440	439	436	435	434	432	5,286
	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	411	410	409	407	406	405	402	402	401	399	4,880
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	396	395	394	392	391	391	388	388	387	385	4,705
14	Total Juris. Recoverable Costs (Lines 12 + 13)		433	432	429	428	427	425	424	424	421	420	419	417	5,099

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 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	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)	(59,989)	(60,970)	(61,951)	(62,932)	(63,913)	(64,894)	(65,875)	(66,856)	(67,837)	(68,818)	(69,799)	(70,780)	(71,761)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	331,130	330,149	329,168	328,187	327,206	326,225	325,244	324,263	323,282	322,301	321,320	320,339	319,358	
6	Average Net Investment		330,640	329,659	328,678	327,697	326,716	325,735	324,754	323,773	322,792	321,811	320,830	319,849	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		3,949	3,948	3,938	3,937	3,929	3,920	3,912	3,903	3,892	3,878	3,861	3,854	46,921
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)		3,949	3,948	3,938	3,937	3,929	3,920	3,912	3,903	3,892	3,878	3,861	3,854	46,921

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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(1,143,068)	(1,148,864)	(1,154,660)	(1,160,456)	(1,166,252)	(1,172,048)	(1,177,844)	(1,183,640)	(1,189,436)	(1,195,232)	(1,201,028)	(1,206,824)	(1,212,620)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,639,532	1,633,736	1,627,940	1,622,144	1,616,348	1,610,552	1,604,756	1,598,960	1,593,164	1,587,368	1,581,572	1,575,776	1,569,980	
6	Average Net Investment		1,636,634	1,630,838	1,625,042	1,619,246	1,613,450	1,607,654	1,601,858	1,596,062	1,590,266	1,584,470	1,578,674	1,572,878	
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	11,599	11,556	141,482
	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	20,690	20,635	251,224
	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	1,592	1,587	19,325
	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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		1,574	1,572	1,568	1,567	1,564	1,559	1,555	1,551	1,546	1,541	1,534	1,529	18,660
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 Juris. Recoverable Costs (Lines 12 + 13)		20,475	20,425	20,371	20,322	20,270	20,217	20,164	20,111	20,058	20,004	19,949	19,895	242,261

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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	99,998	99,625	99,252	98,879	98,506	98,133	97,760	97,387	97,014	96,641	96,268	95,895	95,522	
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)	278,960	278,587	278,214	277,841	277,468	277,095	276,722	276,349	275,976	275,603	275,230	274,857	274,484	
6	Average Net Investment		278,774	278,401	278,028	277,655	277,282	276,909	276,536	276,163	275,790	275,417	275,044	274,671	
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	2,023	2,021	2,018	24,396
	b Debt Component (Line 6 x Debt Component x 1/12)		582	581	580	579	579	578	577	576	576	575	574	573	6,930
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)		3,003	2,999	2,996	2,992	2,989	2,985	2,982	2,978	2,975	2,971	2,968	2,964	35,802
	a Recoverable Costs Allocated to Energy		231	231	230	230	230	230	229	229	229	229	228	228	2,754
	b Recoverable Costs Allocated to Demand		2,772	2,768	2,766	2,762	2,759	2,755	2,753	2,749	2,746	2,742	2,740	2,736	33,048
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		222	223	222	222	222	222	221	221	221	221	220	220	2,657
13	Retail Demand-Related Recoverable Costs (I)		2,673	2,669	2,667	2,663	2,660	2,656	2,654	2,651	2,648	2,644	2,642	2,638	31,865
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,895	2,892	2,889	2,885	2,882	2,878	2,875	2,872	2,869	2,865	2,862	2,858	34,522

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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	7,394	0	0	0	0	0	0	0	0	0	
	c Retirements		0	587,181	587,181	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	461,063	461,064	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)	16,193,793	16,193,793	15,606,612	15,026,825	15,026,825	15,026,825	15,026,825	15,026,825	15,026,825	15,026,825	15,026,825	15,026,825	15,026,825	
3	Less: Accumulated Depreciation (C)	(6,517,266)	(6,569,406)	(5,572,544)	(4,574,174)	(4,623,300)	(4,672,426)	(4,721,552)	(4,770,678)	(4,819,804)	(4,868,930)	(4,918,056)	(4,967,182)	(5,016,308)	
4	CWIP - Non Interest Bearing	7,394	7,394	7,394	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	9,683,921	9,631,781	10,041,462	10,452,651	10,403,525	10,354,399	10,305,273	10,256,147	10,207,021	10,157,895	10,108,769	10,059,643	10,010,517	
6	Average Net Investment		9,657,851	9,836,622	10,247,057	10,428,088	10,378,962	10,329,836	10,280,710	10,231,584	10,182,458	10,133,332	10,084,206	10,035,080	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		70,956	72,270	75,285	76,615	76,254	75,893	75,532	75,171	74,811	74,450	74,089	73,728	895,054
	b Debt Component (Line 6 x Debt Component x 1/12)		20,156	20,529	21,386	21,763	21,661	21,558	21,456	21,353	21,251	21,148	21,046	20,943	254,250
8	Investment Expenses														
	a Depreciation (E)		41,828	41,070	39,563	38,814	38,814	38,814	38,814	38,814	38,814	38,814	38,814	38,814	471,787
	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		27,908	27,908	27,908	27,908	27,908	27,908	27,908	27,908	27,908	27,908	27,908	27,908	334,896
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		171,160	172,089	174,454	175,412	174,949	174,485	174,022	173,558	173,096	172,632	172,169	171,705	2,079,731
	a Recoverable Costs Allocated to Energy		13,166	13,237	13,419	13,493	13,457	13,422	13,386	13,351	13,315	13,279	13,244	13,207	159,976
	b Recoverable Costs Allocated to Demand		157,994	158,852	161,035	161,919	161,493	161,064	160,636	160,209	159,780	159,353	158,924	158,496	1,919,755
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		12,681	12,776	12,945	13,043	13,015	12,980	12,947	12,913	12,868	12,821	12,760	12,728	154,477
13	Retail Demand-Related Recoverable Costs (I)		152,340	153,168	155,273	156,125	155,714	155,300	154,888	154,476	154,062	153,651	153,237	152,824	1,851,058
14	Total Juris. Recoverable Costs (Lines 12 + 13)		165,021	165,944	168,218	169,168	168,729	168,280	167,835	167,389	166,930	166,472	165,997	165,552	2,005,535

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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	
3	Less: Accumulated Depreciation (C)	(18,578)	(18,858)	(19,138)	(19,418)	(19,698)	(19,978)	(20,258)	(20,538)	(20,818)	(21,098)	(21,378)	(21,658)	(21,938)	
4	CWIP - Non Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	115,557	115,277	114,997	114,717	114,437	114,157	113,877	113,597	113,317	113,037	112,757	112,477	112,197	
6	Average Net Investment		115,417	115,137	114,857	114,577	114,297	114,017	113,737	113,457	113,177	112,897	112,617	112,337	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		848	846	844	842	840	838	836	834	832	829	827	825	10,041
	b Debt Component (Line 6 x Debt Component x 1/12)		241	240	240	239	239	238	237	237	236	236	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	1,359	1,356	1,353	1,351	1,348	1,345	1,342	1,339	16,253
	a Recoverable Costs Allocated to Energy		105	105	105	105	105	104	104	104	104	103	103	103	1,250
	b Recoverable Costs Allocated to Demand		1,264	1,261	1,259	1,256	1,254	1,252	1,249	1,247	1,244	1,242	1,239	1,236	15,003
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		101	101	101	101	102	101	101	101	101	99	99	99	1,207
13	Retail Demand-Related Recoverable Costs (I)		1,219	1,216	1,214	1,211	1,209	1,207	1,204	1,202	1,199	1,198	1,195	1,192	14,466
14	Total Juris. Recoverable Costs (Lines 12 + 13)		1,320	1,317	1,315	1,312	1,311	1,308	1,305	1,303	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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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, 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	720,000	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	2,217,055	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	1,000,000	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	300,000	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)	134,527,864	134,527,864	134,527,864	135,744,919	135,744,919	135,744,919	135,744,919	135,744,919	135,744,919	135,744,919	135,744,919	135,744,919	135,744,919	
3	Less: Accumulated Depreciation (C)	(17,512,043)	(17,901,287)	(18,290,531)	(17,381,398)	(17,773,888)	(18,166,378)	(18,558,868)	(18,951,358)	(19,343,848)	(19,736,338)	(20,128,828)	(20,521,318)	(20,913,808)	
4	CWIP - Non Interest Bearing (J)	1,497,055	1,497,055	1,497,055	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	118,512,875	118,123,631	117,734,387	118,363,520	117,971,030	117,578,540	117,186,050	116,793,560	116,401,070	116,008,580	115,616,090	115,223,600	114,831,110	
6	Average Net Investment		118,318,253	117,929,009	118,048,954	118,167,275	117,774,785	117,382,295	116,989,805	116,597,315	116,204,825	115,812,335	115,419,845	115,027,355	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		869,284	866,424	867,306	868,175	865,291	862,408	859,524	856,640	853,757	850,873	847,990	845,106	10,312,778
	b Debt Component (Line 6 x Debt Component x 1/12)		246,930	246,118	246,368	246,615	245,796	244,977	244,158	243,339	242,519	241,700	240,881	240,062	2,929,463
8	Investment Expenses														
	a Depreciation (E)		358,272	358,272	359,895	361,518	361,518	361,518	361,518	361,518	361,518	361,518	361,518	361,518	4,330,101
	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)		1,505,458	1,501,786	1,504,541	1,507,280	1,503,577	1,499,875	1,496,172	1,492,469	1,488,766	1,485,063	1,481,361	1,477,658	17,944,006
	a Recoverable Costs Allocated to Energy		1,505,458	1,501,786	1,504,541	1,507,280	1,503,577	1,499,875	1,496,172	1,492,469	1,488,766	1,485,063	1,481,361	1,477,658	17,944,006
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		1,450,008	1,449,428	1,451,428	1,456,972	1,454,169	1,450,479	1,447,095	1,443,467	1,438,750	1,433,843	1,427,169	1,424,085	17,326,893
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)		1,450,008	1,449,428	1,451,428	1,456,972	1,454,169	1,450,479	1,447,095	1,443,467	1,438,750	1,433,843	1,427,169	1,424,085	17,326,893

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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.'s 1272 & 1401
(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		5,000	10,000	10,000	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	25,000	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)	919,839	919,839	919,839	944,839	944,839	944,839	944,839	944,839	944,839	944,839	944,839	944,839	944,839	
3	Less: Accumulated Depreciation (C)	(60,064)	(62,517)	(64,970)	(67,449)	(69,954)	(72,459)	(74,964)	(77,469)	(79,974)	(82,479)	(84,984)	(87,489)	(89,994)	
4	CWIP - Non Interest Bearing	0	5,000	15,000	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	859,775	862,322	869,869	877,390	874,885	872,380	869,875	867,370	864,865	862,360	859,855	857,350	854,845	
6	Average Net Investment		861,049	866,096	873,630	876,138	873,633	871,128	868,623	866,118	863,613	861,108	858,603	856,098	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,326	6,363	6,419	6,437	6,419	6,400	6,382	6,363	6,345	6,327	6,308	6,290	76,379
	b Debt Component (Line 6 x Debt Component x 1/12)		1,797	1,808	1,823	1,829	1,823	1,818	1,813	1,808	1,802	1,797	1,792	1,787	21,697
8	Investment Expenses														
	a Depreciation (E)		2,453	2,453	2,479	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	29,930
	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)		10,576	10,624	10,721	10,771	10,747	10,723	10,700	10,676	10,652	10,629	10,605	10,582	128,006
	a Recoverable Costs Allocated to Energy		814	817	825	829	827	825	823	821	819	818	816	814	9,848
	b Recoverable Costs Allocated to Demand		9,762	9,807	9,896	9,942	9,920	9,898	9,877	9,855	9,833	9,811	9,789	9,768	118,158
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	789	796	801	800	798	796	794	791	790	786	784	9,509
13	Retail Demand-Related Recoverable Costs (I)		9,413	9,456	9,542	9,586	9,565	9,544	9,524	9,502	9,481	9,460	9,439	9,418	113,930
14	Total Juris. Recoverable Costs (Lines 12 + 13)		10,197	10,245	10,338	10,387	10,365	10,342	10,320	10,296	10,272	10,250	10,225	10,202	123,439

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $919,839; Smith $0. Ending Balances: Crist $919,839; 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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(9,913)	(10,081)	(10,249)	(10,417)	(10,585)	(10,753)	(10,921)	(11,089)	(11,257)	(11,425)	(11,593)	(11,761)	(11,929)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	52,957	52,789	52,621	52,453	52,285	52,117	51,949	51,781	51,613	51,445	51,277	51,109	50,941	
6	Average Net Investment		52,873	52,705	52,537	52,369	52,201	52,033	51,865	51,697	51,529	51,361	51,193	51,025	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		388	387	386	385	384	382	381	380	379	377	376	375	4,580
	b Debt Component (Line 6 x Debt Component x 1/12)		110	110	110	109	109	109	108	108	108	107	107	106	1,301
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)		666	665	664	662	661	659	657	656	655	652	651	649	7,897
	a Recoverable Costs Allocated to Energy		666	665	664	662	661	659	657	656	655	652	651	649	7,897
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		641	642	641	640	639	637	635	634	633	630	627	625	7,624
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)		641	642	641	640	639	637	635	634	633	630	627	625	7,624

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 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	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)	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	29,766,045	
3	Less: Accumulated Depreciation (C) (J)	(1,446,464)	(1,516,776)	(1,587,088)	(1,657,400)	(1,727,712)	(1,798,024)	(1,868,336)	(1,938,648)	(2,008,960)	(2,079,272)	(2,149,584)	(2,219,896)	(2,290,208)	
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)	28,319,581	28,249,269	28,178,957	28,108,645	28,038,333	27,968,021	27,897,709	27,827,397	27,757,085	27,686,773	27,616,461	27,546,149	27,475,837	
6	Average Net Investment		28,284,425	28,214,113	28,143,801	28,073,489	28,003,177	27,932,865	27,862,553	27,792,241	27,721,929	27,651,617	27,581,305	27,510,993	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		207,806	207,289	206,773	206,256	205,739	205,223	204,706	204,190	203,673	203,156	202,640	202,123	2,459,574
	b Debt Component (Line 6 x Debt Component x 1/12)		59,030	58,883	58,736	58,589	58,443	58,296	58,149	58,002	57,856	57,709	57,562	57,415	698,670
8	Investment Expenses														
	a Depreciation (E)		70,312	70,312	70,312	70,312	70,312	70,312	70,312	70,312	70,312	70,312	70,312	70,312	843,744
	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)		337,148	336,484	335,821	335,157	334,494	333,831	333,167	332,504	331,841	331,177	330,514	329,850	4,001,988
	a Recoverable Costs Allocated to Energy		337,148	336,484	335,821	335,157	334,494	333,831	333,167	332,504	331,841	331,177	330,514	329,850	4,001,988
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		324,730	324,753	323,966	323,971	323,503	322,837	322,239	321,587	320,693	319,755	318,423	317,891	3,864,348
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)		324,730	324,753	323,966	323,971	323,503	322,837	322,239	321,587	320,693	319,755	318,423	317,891	3,864,348

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $13,925,707; Smith $15,715,201; Scholz $125,137. Ending Balances: Crist, $13,925,707; Smith $15,715,201; Scholz $125,137.
(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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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) 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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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	375,000	0	0	0	905,000	
	b Clearings to Plant (J)		0	0	0	0	0	0	0	375,000	0	0	0	905,000	
	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)	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	468,735	468,735	468,735	468,735	1,373,735	
3	Less: Accumulated Depreciation (C)	(6,148)	(6,398)	(6,648)	(6,898)	(7,148)	(7,398)	(7,648)	(7,898)	(8,648)	(9,898)	(11,148)	(12,398)	(14,855)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	87,587	87,337	87,087	86,837	86,587	86,337	86,087	85,837	460,087	458,837	457,587	456,337	1,358,880	
6	Average Net Investment		87,462	87,212	86,962	86,712	86,462	86,212	85,962	272,962	459,462	458,212	456,962	907,609	
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	2,005	3,376	3,366	3,357	6,668	23,232
	b Debt Component (Line 6 x Debt Component x 1/12)		183	182	181	181	180	180	179	570	959	956	954	1,894	6,599
8	Investment Expenses														
	a Depreciation (E)		250	250	250	250	250	250	250	750	1,250	1,250	1,250	2,457	8,707
	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)		1,076	1,073	1,070	1,068	1,065	1,063	1,061	3,325	5,585	5,572	5,561	11,019	38,538
	a Recoverable Costs Allocated to Energy		83	83	82	82	82	82	82	256	430	429	428	848	2,967
	b Recoverable Costs Allocated to Demand		993	990	988	986	983	981	979	3,069	5,155	5,143	5,133	10,171	35,571
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	248	416	414	412	817	2,862
13	Retail Demand-Related Recoverable Costs (I)		957	955	953	951	948	946	944	2,959	4,971	4,959	4,949	9,807	34,299
14	Total Juris. Recoverable Costs (Lines 12 + 13)		1,037	1,035	1,032	1,030	1,027	1,025	1,023	3,207	5,387	5,373	5,361	10,624	37,161

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) Project # 1298 qualifies for AFUDC treatment. As portions of the project are moved to P-I-S, they are included in the ECRC.

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	
3	Less: Accumulated Depreciation (C)	(497,845)	(513,787)	(529,729)	(545,671)	(561,613)	(577,555)	(593,497)	(609,439)	(625,381)	(641,323)	(657,265)	(673,207)	(689,149)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,479,862	5,463,920	5,447,978	5,432,036	5,416,094	5,400,152	5,384,210	5,368,268	5,352,326	5,336,384	5,320,442	5,304,500	5,288,558	
6	Average Net Investment		5,471,891	5,455,949	5,440,007	5,424,065	5,408,123	5,392,181	5,376,239	5,360,297	5,344,355	5,328,413	5,312,471	5,296,529	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,202	40,085	39,968	39,851	39,733	39,616	39,499	39,382	39,265	39,148	39,031	38,914	474,694
	b Debt Component (Line 6 x Debt Component x 1/12)		11,420	11,387	11,353	11,320	11,287	11,253	11,220	11,187	11,154	11,120	11,087	11,054	134,842
8	Investment Expenses														
	a Depreciation (E)		15,942	15,942	15,942	15,942	15,942	15,942	15,942	15,942	15,942	15,942	15,942	15,942	191,304
	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)		67,564	67,414	67,263	67,113	66,962	66,811	66,661	66,511	66,361	66,210	66,060	65,910	800,840
	a Recoverable Costs Allocated to Energy		5,197	5,186	5,174	5,163	5,151	5,139	5,128	5,116	5,105	5,093	5,082	5,070	61,604
	b Recoverable Costs Allocated to Demand		62,367	62,228	62,089	61,950	61,811	61,672	61,533	61,395	61,256	61,117	60,978	60,840	739,236
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		5,006	5,005	4,991	4,991	4,982	4,970	4,960	4,948	4,933	4,917	4,896	4,886	59,485
13	Retail Demand-Related Recoverable Costs (I)		60,135	60,001	59,867	59,733	59,599	59,465	59,331	59,198	59,064	58,930	58,796	58,663	712,782
14	Total Juris. Recoverable Costs (Lines 12 + 13)		65,141	65,006	64,858	64,724	64,581	64,435	64,291	64,146	63,997	63,847	63,692	63,549	772,267

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 2009 - December 2009

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		4,337,917	787,183	1,758,862	0	0	0	0	0	0	0	0	512,352,026	
	b Clearings to Plant (J)		4,104,484	299,381	5,185,558	0	0	0	0	0	0	0	0	512,352,026	
	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) (K)	65,188,195	69,292,679	69,592,059	74,777,617	74,777,617	74,777,617	74,777,617	74,777,617	74,777,617	74,777,617	74,777,617	74,777,617	587,129,643	
3	Less: Accumulated Depreciation (C)	(1,901,501)	(2,073,972)	(2,252,201)	(2,436,527)	(2,626,637)	(2,816,747)	(3,006,857)	(3,196,967)	(3,387,077)	(3,577,187)	(3,767,297)	(3,957,407)	(4,830,738)	
4	CWIP - Non Interest Bearing	2,873,203	3,106,636	3,594,438	167,742	167,742	167,742	167,742	167,742	167,742	167,742	167,742	167,742	167,742	
5	Net Investment (Lines 2 + 3 + 4)	66,159,897	70,325,343	70,934,297	72,508,833	72,318,723	72,128,613	71,938,503	71,748,393	71,558,283	71,368,173	71,178,063	70,987,953	582,466,648	
6	Average Net Investment		68,242,620	70,629,820	71,721,565	72,413,778	72,223,668	72,033,558	71,843,448	71,653,338	71,463,228	71,273,118	71,083,008	326,727,300	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		501,379	518,917	526,938	532,024	530,627	529,231	527,834	526,437	525,040	523,644	522,247	2,400,465	8,164,783
	b Debt Component (Line 6 x Debt Component x 1/12)		142,422	147,404	149,683	151,128	150,731	150,334	149,937	149,541	149,144	148,747	148,350	681,880	2,319,301
8	Investment Expenses														
	a Depreciation (E)		172,013	177,771	183,868	189,652	189,652	189,652	189,652	189,652	189,652	189,652	189,652	872,873	2,923,741
	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)		816,272	844,550	860,947	873,262	871,468	869,675	867,881	866,088	864,294	862,501	860,707	3,955,676	13,413,321
	a Recoverable Costs Allocated to Energy		816,272	844,550	860,947	873,262	871,468	869,675	867,881	866,088	864,294	862,501	860,707	3,955,676	13,413,321
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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)		786,207	815,106	830,554	844,116	842,831	841,034	839,413	837,652	835,257	832,753	829,220	3,812,262	12,946,405
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)		786,207	815,106	830,554	844,116	842,831	841,034	839,413	837,652	835,257	832,753	829,220	3,812,262	12,946,405

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $49,165,896; Smith $11,346,149; Daniel $4,020,088, Scholz $656,162. Ending Balances: Crist $566,700,055; Smith $15,586,062, Daniel $4,187,364, Scholz $656,162.
(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.
(K) Smith beginning balances differ from 2008 estimated/actual true-up due to updated projections.

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2009 Projection Filing
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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)	(4,728)	(5,122)	(5,516)	(5,910)	(6,304)	(6,698)	(7,092)	(7,486)	(7,880)	(8,274)	(8,668)	(9,062)	(9,456)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	18,926	18,532	18,138	17,744	17,350	16,956	16,562	16,168	15,774	15,380	14,986	14,592	14,198	
6	Average Net Investment		18,729	18,335	17,941	17,547	17,153	16,759	16,365	15,971	15,577	15,183	14,789	14,395	
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	41	42	42	41	41	41	41	40	40	40	493
13	Retail Demand-Related Recoverable Costs (I)		508	504	501	498	495	492	488	484	481	479	475	472	5,877
14	Total Juris. Recoverable Costs (Lines 12 + 13)		550	546	542	540	537	533	529	525	522	519	515	512	6,370

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

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2009 Projection Filing
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 - December 2009
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		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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 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

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2009 Projection Filing
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2009 - December 2009

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		0	0	0	0	1,600,000	4,015,000	2,037,500	2,197,280	2,197,280	2,197,280	2,197,280	2,197,280	
	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	1,600,000	4,969,444	4,612,490	3,559,871	2,501,346	2,046,685	1,584,873	3,115	
	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	1,600,000	4,969,444	4,612,490	3,559,871	2,501,346	2,046,685	1,584,873	3,115	
4	Average Net Working Capital Balance		0	0	0	0	800,000	3,284,722	4,790,967	4,086,181	3,030,609	2,274,016	1,815,779	793,994	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12)(A)		0	0	0	0	5,878	24,133	35,199	30,021	22,266	16,707	13,341	5,833	153,378
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	1,670	6,855	9,999	8,528	6,325	4,746	3,790	1,657	43,570
6	Total Return Component (D)		0	0	0	0	7,548	30,988	45,198	38,549	28,591	21,453	17,131	7,490	196,948
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		0	0	0	0	0	645,556	2,394,454	3,249,899	3,255,805	2,651,941	2,659,092	3,779,038	18,635,785
8	Net Expenses (E)		0	0	0	0	0	645,556	2,394,454	3,249,899	3,255,805	2,651,941	2,659,092	3,779,038	18,635,785
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	7,548	676,544	2,439,652	3,288,448	3,284,396	2,673,394	2,676,223	3,786,528	18,832,733
	a Recoverable Costs Allocated to Energy		0	0	0	0	7,548	676,544	2,439,652	3,288,448	3,284,396	2,673,394	2,676,223	3,786,528	18,832,733
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9624937	0.9644610	0.9640232	0.9659474	0.9664634	0.9663902	0.9665218	0.9664905	0.9657283	0.9648345	0.9627437	0.9630706	
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	7,300	654,263	2,359,627	3,180,479	3,174,054	2,581,188	2,578,320	3,649,246	18,184,477
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)		0	0	0	0	7,300	654,263	2,359,627	3,180,479	3,174,054	2,581,188	2,578,320	3,649,246	18,184,477

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)
January 2009-December 2009

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Air Quality Assurance Testing
PEs 1006 and 1244

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This line item includes the audit test trailer and associated support equipment used to conduct Relative Accuracy Test Audits (RATAs) on the Continuous Emission Monitoring Systems (CEMs) as required by the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The RATA test trailer CEM system was replaced during the 2002-2003 recovery period. The CEMs trailer was also replaced in 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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 $15,031,878 projected at December 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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, 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 $5,222,602 projected at December 2009.

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 are being replaced.

Projections:
During the 2009 recovery period, 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. The existing Crist Units 4 and 5 opacity monitors are approaching the end of their useful lives and will be retired upon replacement. 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. The 2009 expenditures are expected to be approximately $439,830.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 $242,943 projected at December 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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.

Project-to-Date: Plant-in-service of $178,962 projected at December 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 $15,026,825 projected at December 2009.

Progress Summary: In-Service

Projections: The Daniel Ash Management project is projected to have cost of removal expenses and retirements during 2009 for closure of the existing ash storage facility.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Water Conservation
PEs 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 $134,135 projected at December 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009-December 2009

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 $135,744,919 projected at December 2009.

Progress Summary: In-Service

Projections: During 2009, Gulf will be replacing a layer of the Crist Unit 7 SCR catalyst. This new layer of catalyst is part of the on-going periodic catalyst maintenance and management activity. The projected 2009 expenditures for the Crist FDEP Agreement projects are $720,000. Gulf has also projected cost of removal expenses and retirements during 2009 for this project.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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).

The 2006 SPCC project at Plant Crist was designed to route stormwater from the switchyard drains to the new oil skimming sump where any potential spill would be captured, preventing the oil from reaching surface water. During 2009, Plant Smith plans to install secondary containment for a small fuel tank and a padmount transformer.

Accomplishments: Construction on the Plant Crist switchyard sump was completed during 2006.

Project-to-Date: Plant-in-service of $944,839 projected at December 2009.

Progress Summary: In-service

Projections: The projected 2009 expenditures for the Plant Smith SPCC Compliance project are $25,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 $29,766,045 projected at December 2009.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009-December 2009

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 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 negotiations 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 Northwest Florida Water Management District has agreed that this is a valid project to pursue for continued implementation of the water conservation effort. Gulf expects to place portions of this project in-service during 2009.

Accomplishments: Level controls were installed on the fire tank system during 2006.

Project-to-Date: Plant-in-service of $1,373,735 projected at December 2009.

Progress Summary: See Accomplishments

Projections: Expenditures totaling $1.3 million are projected to be incurred for portions of the Plant Crist Water Conservation project that will be placed-in-service during 2009.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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. Plant Crist also plans to install a chemical treatment system during 2008 to reduce iron and copper concentrations in the ash pond discharge.

Project-to-Date: Plant-in-service of $5,977,707 projected at December 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 $586,662,113 projected at December 2009.

Progress Summary: See Accomplishments

Projections:
For the purpose of the 2009 projection of ECRC revenue requirements, expenditures totaling approximately $519 million are projected to be incurred for capital projects included in the CAIR/CAMR/CAVR Compliance Program. These capital projects include the Crist Units 4 through 7 scrubber project ($517.5 million), Low NOx burners at Plant Daniel on Unit 2 ($167,276), and Selective Non-Catalytic Reduction (SNCR) technologies at Plant Smith on Unit 1 ($3.9 million) and Unit 2 ($371,502).

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Mercury Allowances

FPSC Approval: Stipulation approved by the Commission on August 14, 2007

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 2009-December 2009

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Annual NO_x Allowances

FPSC Approval: Stipulation approved by the Commission on August 14, 2007

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:

Annual NOx allowance expenses have been included in Gulf's 2009 projection filing because CAIR will remain in effect unless and until the court issues a mandate in the case.

Projections: The 2009 projection expenses for annual allowances are $18.6 million. This projection will be updated if the CAIR is ultimately vacated.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Seasonal NO_x Allowances

FPSC Approval: Stipulation approved by the Commission on August 14, 2007

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:

Seasonal NOx allowance expenses have been included in Gulf's 2009 projection filing because CAIR will remain in effect unless and until the court issues a mandate in the case.

Projections: The 2009 projection expenses for seasonal NOx allowances are $2.2 million. This projection will be updated if the CAIR is ultimately vacated.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 utilizes 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 executed forward contacts to secure allowances during 2007.

Project-to-Date: N/A

Progress Summary: See Accomplishments

Projections: Gulf expects to purchase $8.8 million of SO_2 allowances in 2009. Based on allowance usage, the expenses (net of gains) are projected to be approximately $5.9 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009-December 2009

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: $849,374

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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. During 2004, the Title V renewal applications were submitted for Plant Crist, Smith, and Scholz. The final permits were issued in December 2004 and February 2005.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $129,352

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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: $2,500

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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. Other activities within this category include testing for the Periodic Monitoring and Compliance Assurance Monitoring (CAM) requirements associated with the CAAA of 1990.

Accomplishments:
All systems are in compliance.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $656,209

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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: $556,074

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 46 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,631,176

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009-December 2009

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: $20,400

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.10

Title: Environmental Auditing/Assessment

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Environmental Auditing/Assessment program ensures continued compliance with environmental laws, rules, and regulations through auditing and/or assessment of company facilities and operations.

Accomplishments:
Audits and assessments completed to date have demonstrated compliance with environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $7,300

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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: $417,471

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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: $90,100

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009-December 2009

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: $800,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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: $313,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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 2009-December 2009

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 2009-December 2009

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: $5,972,528

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2009-December 2009

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.
Gulf Power expects to begin incurring annual costs associated with joining the Climate Registry during 2009. Gulf also anticipates incurring expenses for monitoring and reporting greenhouse gas emissions.

Accomplishments: Gulf will begin 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. Gulf also expects to begin incurring annual costs associated with joining the climate registry in 2009.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $6,013,528

Schedule 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2009 - December 2009

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Jan - Dec. 2009 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%	5,882,421,000	1,157,367.59	1.0048648	1.0053010	5,913,603,537	1,162,997.91	49.51975%	58.63493%
GS	63.781436%	344,451,000	61,649.43	1.0048589	1.0052978	346,275,815	61,948.98	2.89967%	3.12329%
GSD, GSDT, GSTOU	75.860452%	2,558,412,000	384,991.33	1.0047057	1.0051660	2,571,628,859	386,802.96	21.53448%	19.50147%
LP, LPT	86.886296%	1,946,852,000	255,786.46	0.9842260	0.9891199	1,925,670,036	251,751.67	16.12531%	12.69258%
PX, PXT, RTP, SBS	104.683592%	1,054,375,000	114,977.37	0.9744382	0.9805725	1,033,891,161	112,038.34	8.65767%	5.64864%
OS-I/II	321.885641%	117,699,000	4,174.14	1.0046893	1.0052949	118,322,199	4,193.71	0.99081%	0.21143%
OS-III	99.718369%	32,349,000	3,703.24	1.0051151	1.0052683	32,519,423	3,722.18	0.27231%	0.18766%
TOTAL		11,936,559,000	1,982,649.56			11,941,911,030	1,983,455.75	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 2008 - December 2008
(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 2009 - December 2009

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	49.51975%	58.63493%	39,697,817	3,516,789	43,214,606	5,882,421,000	0.735
GS	2.89967%	3.12329%	2,324,539	187,328	2,511,867	344,451,000	0.729
GSD, GSDT, GSTOU	21.53448%	19.50147%	17,263,250	1,169,654	18,432,904	2,558,412,000	0.720
LP, LPT	16.12531%	12.69258%	12,926,956	761,272	13,688,228	1,946,852,000	0.703
PX, PXT, RTP, SBS	8.65767%	5.64864%	6,940,475	338,793	7,279,268	1,054,375,000	0.690
OS-I, OS-II	0.99081%	0.21143%	794,289	12,681	806,970	117,699,000	0.686
OS-III	0.27231%	0.18766%	218,299	11,255	229,554	32,349,000	0.710
TOTAL	100.00000%	100.00000%	$80,165,625	$5,997,772	$86,163,397	11,936,559,000	0.722

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 2008 - December 2008
(7) Col 5 / Col 6 x 100