BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 030007-EI
FLORIDA POWER & LIGHT COMPANY

SEPTEMBER 8, 2003

ENVIRONMENTAL COST RECOVERY

PROJECTIONS
JANUARY 2004 THROUGH DECEMBER 2004

TESTIMONY & EXHIBITS OF:

K. M. DUBIN
R. R. LABAUVE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 030007-EI

SEPTEMBER 8, 2003

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 Manager of Regulatory Issues in the Regulatory Affairs 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 the proposed Environmental Cost Recovery Clause (ECRC) projections for the January 2004 through December 2004 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. It 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 Environmental costs being presented for the period January 2004 through December 2004. Total environmental costs, adjusted for revenue taxes, amount to $12,945,763 (Appendix I, Page 2, Line 5a) and include $13,798,551 of environmental project costs (Appendix I, Page 2, Line 1c) decreased by the estimated/ actual overrecovery of $850,933 for the January 2003 -

December 2003 period as filed on August 8, 2003 (Appendix I, Page 2, Line 2) and the final overrecovery of $205,349 for the April 15, 2002 – December 31, 2002 period as filed on April 1, 2003 (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 O&M project 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 capital investment project costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand.

Forms 42-2P and 42-3P present the method of classifying costs consistent with Order No. PSC-94-0393-FOF-EI.

Q. Please describe Form 42-4P.

A. Form 42-4P (Appendix I, Pages 7 through 41) 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 42 through 70) provides the description and progress of environmental compliance activities and projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 71) 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 72) 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 Pt. Everglades Electrostatic Precipitator ("ESP") Technology Project, the Underground Storage Tank Replacement/Removal ("UST Replacement/Removal") Project, and the Lowest Quality Water Source ("LQWS") Project, which are presented in the testimony of R. R. LaBauve. The projected costs for these projects are included on the following schedules:

ESP	Project No. 25	Appendix I, Pages 5-6
UST	Project No. 26	Appendix I, Pages 3-4
LQWS	Project No. 27	Appendix I, Pages 3-4

Q. Is FPL presenting any other issues to be addressed in the ECRC?

A. Yes. Pursuant to Order No. PSC-94-0044-FOF-EI in Docket No. 930613-EI, issued on January 12, 1994, FPL is requesting recovery through the ECRC of carrying costs associated with Construction Work In Progress (CWIP) related to the Manatee Reburn Project and the Pt. Everglades ESP Technology Project capital investments. Projected capital investments associated with these projects do not qualify for an Allowance for Funds Used During Construction (AFUDC), pursuant to F.A.C. Rule 25-6.0141, and therefore, FPL is entitled to seek recovery of these carrying costs through the ECRC. FPL has included the return on CWIP for these projects for the 2004 projected period in its calculation of the 2004 ECRC factors. Additionally, the return on CWIP for these projects for 2003 will be included in the 2003 Final True-up Filing that will be filed in April of 2004.

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. 030007-EI

September 8, 2003

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 the Commission's review and approval, three new environmental projects – the Underground Storage Tank Replacement/Removal ("UST Replacement/Removal") Project, the Lowest Quality Water Source

("LQWS") Project, and the Port Everglades Electrostatic Precipitator ("ESP") Technology Project.

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

A. Yes. It consists of the following documents:

- Document RRL-1, Florida Administrative Code, Title 62 – Department of Environmental Protection, Rule 62-761.500.
- Document RRL-2, FPL's Existing Underground Storage Tank Systems
- Document RRL-3, St. John's River Water Management District Consumptive Use Permit Number 10652, Cape Canaveral Plant.
- Document RRL-4, St. John's River Water Management District Consumptive Use Permit Number 9202, Sanford Plant.
- Document RRL-5, <u>Draft</u> Title V Air Permit, Port Everglades Plant.
- Document RRL-6, Advantages/Disadvantages – Particulate Removal Technologies.
- Document RRL-7, Advantages/Disadvantages – SO_3 Removal Technologies.

UNDERGROUND STORAGE TANK ("UST")
REPLACEMENT/REMOVAL PROJECT

Q. Please describe the law or regulation requiring the UST Replacement/Removal Project.

A. Florida Administrative Code (FAC) Title 62 – Department of Environmental Protection, Rule 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. This regulation requires that all single-walled underground storage tank ("UST") systems or piping in contact with the soil connected to the UST that contain pollutants or hazardous substances be removed or replaced with tanks that that are constructed with secondary containment. Storage tanks with secondary containment include double-walled USTs, double-walled aboveground storage tanks ("ASTs"), or ASTs installed with secondary containment surrounding the tank (e.g., concrete walls and floor). Rule 62-761.500 is provided as Document RRL-1.

Q. What are Category-A Storage Tank Systems?

A. Category-A Storage Tank Systems include single-walled tanks or underground single-walled piping with no secondary containment which were installed before June 30, 1992.

Q. What are Category-B Storage Tank Systems?

A. Category-B Storage Tank Systems include tanks that contain pollutants and were installed after June 30, 1992 or tanks that contain hazardous substances and were installed after January 1, 1991. Also included is any small diameter piping that comes in contact with the soil that is connected to a UST that was installed after December 10, 1990.

Q. What are Category-C Storage Tank Systems?

A. Category-C Storage Tank Systems include tanks that 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, overfill protection, and were installed on or after July of 1998.

Q. How does Rule 61-761.500 impact FPL?

A. 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. Document RRL- 2 provides a list and description of FPL's existing UST systems.

Q. Please describe the UST Replacement/Removal Project.

A. 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 ASTs 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 Rule 62-761.800 and closure assessment reports will be submitted to local counties, the Department of Environmental Resource Management (DERM) (Miami-Dade County, only), and the Florida Department of Environmental Protection (DEP).

Q. What alternatives did FPL consider?

A. FPL considered upgrading the USTs to comply with the standards for Category-C Tank Storage Systems. The cost to upgrade the USTs and integral piping would be approximately $150,000 per tank as compared to $120,000 for the removal, cost, and installation of a new AST. Additionally, environmental issues such as the hazardous nature of the contents of the USTs, their inaccessibility for inspection, and length of time in the ground were also considered in the decision to remove and replace the USTs.

Q. Why is FPL implementing the UST Replacement/Removal Project at this time?

A. FPL's decision to implement the UST Replacement/Removal Project at this time was primarily driven by environmental concerns. Due to the length of time these tanks have been underground and the potential for corrosion and leakage, FPL believes that removing/replacing them during 2004-2006 may prevent additional costs associated with containment and clean-up issues.

Q. Has FPL estimated the cost of the UST Replacement/Removal Project?

A. FPL's O&M cost estimate for the Project is $280,000, to be incurred in 2004 through 2006. FPL's timeline for the removal/replacement of its existing USTs will ensure that the performance standards of Rule 62-761.500 are met by the date specified.

Q. Has FPL estimated how much will be spent on the Project in 2004?

A. FPL expects to spend $148,050 of O&M costs in 2004 for the removal and replacement of the USTs at Turkey Point Units 1 and 2, and the removal of the UST at the Fort Lauderdale Plant. Closure assessments for these tank systems will be performed and reports will be produced. FPL does not project that it will incur any capital costs for this project.

<u>LOWEST QUALITY WATER SOURCE ("LQWS") PROJECT</u>

Q. What is the statutory basis for FPL's request to recover LQWS Project costs in this docket?

A. 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." As I explain below, 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 and Cape

Canaveral Plants. 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 Cape Canaveral Plant CUP is provided as Document RRL-3 and the Sanford Plant CUP is provided as Document RRL-4.

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 and Cape Canaveral Plants 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 requirement for the Cape Canaveral Plant is found in Conditions 14 and 15 of CUP No. 10652, issued October 2001, which address the quantity of reclaimed water to be used and require that all available reclaimed water be used prior to groundwater.

Q. **Please briefly describe the scope of the LQWS Project at the Sanford Plant.**

A. Prior to the issuance of CUP No. 9202, groundwater was used as the only source of water to the Plant's reverse osmosis water treatment system (RO system). Ground water was treated in the RO system to produce demineralized water. Demineralized water is ultra-pure water that is used in the Plant's Heat Recovery Steam Generation (HRSG)/ water/steam cycle units.

In order to comply with CUP No. 9202, both ground water and surface water must now be used as sources of water to the RO system. Surface water, which is of lower quality than groundwater, requires pretreatment prior to the RO process. The purpose of the pretreatment is to remove solids, hardness and organics from the surface water. Without pretreatment the impurities would foul the RO membranes and cause premature failure of the system.

Q. Please briefly describe the scope of the LQWS Project at the Cape Canaveral Plant.

A. As with the Sanford Plant, groundwater was used as the source of water to the Cape Canaveral RO system prior to the new CUP. However, in order to comply with CUP No. 10652, reclaimed water must now be used as a source of water to the RO system. Reclaimed water is the treated wastewater discharged from a wastewater treatment plant. It is of lower quality and greater variability than groundwater, so like the surface water that is now used at Sanford Plant, the reclaimed water requires pretreatment prior to the RO process.

Q. What is the projected cost of the LQWS project?

A. Both the Sanford and Cape Canaveral Plants currently lease their RO system equipment from US Filter Corporation. FPL is requesting recovery of the additional O&M costs associated with the lease of pretreatment equipment from US Filter, as well as the cost of chemicals and contractor labor. For the Sanford Plant, these additional costs are projected to be $278,988 annually beginning in 2004. For the Cape Canaveral Plant, the additional O&M costs are expected to be $83,000 annually. FPL also will have to pay Brevard County $0.15 per 1,000 gallons for the reclaimed water used at the Cape Canaveral Plant, which is expected to add $8,212 annually for that plant.

Q. Does FPL expect to incur Project costs in 2003?

A. FPL estimates that it will spend $93,000 of O&M costs at the Sanford Plant beginning in September of 2003. Since my testimony reflects projections for the period January 2004 through December 2004, actual costs for 2003 will be included in the 2003 Final True-up Filing which will be filed in April of 2004.

Q. Has FPL estimated how much will be spent on the Project in 2004?

A. FPL estimates that it will spend $370,200 of O&M costs at the Sanford and Cape Canaveral Plants in 2004. As I will explain later in my testimony, FPL has not included any capital costs associated with this project in its ECRC filing.

Q. Are the costs to be incurred for the LQWS Project prudent and reasonable?

A. Yes. A lease versus purchase analysis was performed in order to determine the least cost alternative. If FPL were to purchase the pretreatment equipment, costs would be approximately $1 million. The lease for the pretreatment system has been obtained through the bidding process.

Q. What alternatives did FPL consider?

A. The SJRWMD requires the use of the lowest quality of water that is technically, environmentally and economically feasible for its needs. During the permitting process, FPL evaluated the utilization of reuse water and stormwater versus the existing use of surface (cooling pond) water for the Sanford Plant. Neither option was found to be feasible due to unavailability or lack of infrastructure to collect and manage the resource.

FPL evaluated the utilization of reuse water and stormwater versus reclaimed water at the Cape Canaveral Plant. Neither option was found to be feasible due to unavailability or lack of infrastructure to collect and manage the resource. The Port St. John's Wastewater Treatment Plant is the closest source of lowest quality, reclaimed water for the Cape Canaveral Plant. Additionally, the plant-generated wastestream boiler blowdown is already being reused at Cape Canaveral.

Q. Has FPL incurred any costs associated with the LQWS Project prior to the submittal of this petition?

A. Yes. FPL has incurred capital costs associated with two interconnect waterlines necessary for the operation of the pretreatment systems at the Sanford and Cape Canaveral Plants. The waterline at the Sanford Plant was installed in May 2003 and the waterline at the Cape Canaveral Plant is currently under construction. Additionally, beginning in May 2003, FPL has incurred O&M costs associated with the leasing of the pretreatment system at the Sanford Plant. In calculating the amount for which it is seeking recovery through the ECRC, FPL has excluded the capital costs associated with the waterlines and the 2003 O&M costs associated with the pretreatment system lease at the Sanford

Plant, since these costs were incurred prior to the submittal of this petition.

PORT EVERGLADES ELECTROSTATIC PRECIPITATOR ("ESP") TECHONOLOGY PROJECT

Q. Please briefly describe the scope of the ESP Technology Project.

A. The ESP Technology Project is the addition of pollution control measures at the four fossil fuel steam boilers at the Port Everglades plant, in order to comply with the Environmental Protection Agency's ("EPA") more stringent particulate matter emission standards required by the Port Everglades Plant Title V permit, which is scheduled to be issued by the EPA on September 7, 2003. A draft of the Port Everglades plant Title V permit is provided as Document RRL-5. FPL expects that it will be able to provide the final Port Everglades plant Title V permit on or about September 12, 2003.

Q. What is the statutory basis for FPL's request to recover ESP Technology Project costs in this docket?

A. 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), and lead (Pb). The 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 section 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the 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 HAPs 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. During the renewal process for this permit, local government leaders and interested citizen groups have expressed concern that EPA's National Ambient Air Quality Standards and MACT requirements will be met at the Port Everglades plant. In this regard, the Broward County Board of County Commissioners enacted Resolution 2002-308, which called upon FPL to modify the Port Everglades plant to use cleaner technology in order to reduce the emission of pollutants. Of special concern were particulate emissions, which result in visible plumes from the plant's exhaust stacks.

In order to avoid delay and potential disputes over the Port Everglades plant Title V permit renewal, FPL has negotiated terms for the permit that address the new standards and the public concerns. The DEP's final Title V permit for the Port Everglades plant requires FPL to install pollution control measures at all four Port Everglades units to address those concerns and to insure compliance with the EPA's emissions standards. The Port Everglades ESP Technology Project implements this requirement.

I should note that the EPA is currently developing new National Ambient Air Quality Standards to limit the emissions of fine particulates (PM2.5). The ESP Technology Project will allow the Port Everglades plant to operate to these stringent PM2.5 standards.

Q. Please describe the Port Everglades generating units.

A. The Port Everglades plant has four units with fossil fueled steam boilers, designated as Units 1, 2, 3, and 4. Units 1 and 2 have a nominal electric output rating of 200 megawatts and have identical early 1960's vintage Combustion Engineering boilers. Units 3 and

4 have a nominal electric output rating of 400 megawatts and have identical mid 1960's vintage Foster-Wheeler boilers. All four units burn primarily no. 6 residual fuel oil but also can burn natural gas. The ESP Technology Project is intended to address the particulate emissions resulting from combustion of fuel oil in the Port Everglades units.

Q. Please describe ESP technology.

A. Cold-side ESPs of the size and efficiency required to meet the specified particulate emission limits have been proven in operation on similarly sized oil-fired power plants. Historically, ESPs have been the most widely used particulate removal technology for large utility installations.

Electrostatic precipitators use transformer/rectifiers to energize discharge electrodes that produce a high voltage dc electrical field between the electrodes and grounded collecting plates. Particulate matter entering the electrical field acquires a negative charge and migrates to the grounded collecting plates. A layer of collected particles forms on the collecting plates and is removed periodically by mechanically rapping the plates. The collected particulate drops into hoppers below the precipitator and is subsequently removed by the pneumatic ash handling system.

Recent advances in ESP control technology has increased ESP collection efficiency by enhancing the plate and wire rapping cleaning cycles to match the rate at which particulate is collecting on any given plate. These computerized controls also allow the ESP to operate at the highest voltage possible without allowing sparking which reduces efficiency and increases energy usage. The ESPs that FPL will install at the Port Everglades plant in conjunction with the ESP Technology Project incorporate these advances.

Q. **Would the ESPs alone meet the standards required by the new Port Everglades plant Title V permit?**

A. No. There are two types of particulate emissions. The first is solid, "dry" particulates of the sort that result in dark plumes from exhaust stacks. ESPs are well suited to removing these dry particulates. The second type of particulates are in the form of condensation droplets, which produce white, steam-like plumes. ESPs cannot effectively remove condensates by themselves. The new Title V permit for the Port Everglades plant requires FPL to address both types of particulate emissions.

Fossil-fueled plants such as Port Everglades can experience condensation of sulfuric acid (which is generated from the plants' sulfur emissions) that increase measured or observed opacity. This is especially important for oil fueled units, where vanadium in the oil can serve to oxidize a greater amount of SO_2 to SO_3. As long as the exhaust gasses remain above the acid dew point temperatures, the sulfuric acid will not be read as opacity by instrumentation, nor measured as particulate emissions by EPA test procedures (which measure only filterable emissions). However, when the flue gas is cooled to condensation temperatures, plumes from these components become visible.

The ESP Technology Project will use alkaline reagent injection to address this potential for sulfuric acid to form visible condensation, including after the gases exit the exhaust stack. The alkaline reagent injection process controls the emission of SO_3 by reacting it with an alkaline material to form a particulate that can be subsequently removed by the ESPs. Two chemicals that are commonly used for this purpose are magnesium oxide/hydroxide (MgO and $Mg(OH)_2$) and sodium sulfite/bisulfite (Na_2SO_3 and $NaHSO_3$).

MgO is injected as a solution into the back passes of the boiler. The MgO and SO_3 react to form a particulate, magnesium sulfate. Some unreacted reagent remains and is removed in the downstream ESPs.

Q. **What alternatives to ESPs and alkaline reagent injection did FPL consider to address the concerns over particulate emissions from the Port Everglades plant?**

A. FPL first considered two alternatives to using any form of post-combustion particulate removal technology:

<u>Repowering.</u> FPL evaluated repowering the existing fossil steam units with natural gas-fired combined cycle plants. The use of natural gas would substantially reduce particulate emissions, but the cost of repowering made this alternative unattractive.

<u>Exclusive Use of Natural Gas in Existing Units.</u> FPL also looked at the economics of leaving the existing fossil steam units in place but firing them exclusively with natural gas. However, the cost of pipeline expansion and other support facilities to provide the necessary natural gas volume as well as the loss of fuel diversity that would result from agreeing not to use fuel oil made this alternative unattractive.

Once it became clear that some form of post-combustion particulate removal was needed, FPL evaluated several alternative technologies to perform this function. Document RRL-6 addresses the alternatives to ESPs that were considered, while Document RRL-7 addresses the alternatives to alkaline reagent injection. As shown on those documents, ESPs and alkaline reagent injection offer the best combination of cost, removal effectiveness and reliability.

Q. How will FPL ensure that the costs incurred for the ESP Technology Project are prudent and reasonable?

A. The contracting strategy currently planned for the project to ensure prudent and reasonable costs will be as follows:

An owner's engineering contract will be negotiated on a target price basis with a penalty for exceeding the target.

a. A foundation contract will be negotiated on a target price basis (foundations on this site are considered to present the most exposure to risk of all activities performed).

b. Equipment (ESP, MgO Injection and Ash Handling) will be purchased on firm fixed lump sum contracts.

c. Construction (including ESP, Plant interface tie points, commissioning and start-up) will be performed utilizing an EPC contract (Engineering-Procurement-Construction) firm fixed lump sum contract with schedule and performance liquidated damages.

Q. Has FPL estimated the cost of the ESP Technology Project?

A. The following is FPL's capital cost estimates for the years 2003-2007.

Year	Estimated Capital Cost
2003	$968,141
2004	$28,842,941
2005	$29,461,466
2006	$23,402,092
2007	$9,425,360
Total:	$92,100,000

Estimated annual O&M costs are $4.2 million, based on a capacity factor of 50% to 70%.

Q. Does FPL expect to incur Project costs in 2003?

A. FPL estimates that it will spend $968,141 of Capital costs beginning in the fourth quarter of 2003. These Capital costs are primarily associated with engineering design work. Since my testimony reflects projections for the period January 2004 through December

2004, these costs will be included in the 2003 Final True-up Filing which will be filed in April of 2004.

Q. Has FPL estimated how much will be spent on the Project in 2004?

A. FPL estimates that it will spend $28,842,941 of Capital costs in 2004, primarily associated with the purchase of equipment and the beginning phases of construction on Port Everglades Unit #2.

Q. What are the proposed in-service dates for implementing the ESP Technology Project at the four Port Everglades units?

A. The planned in-service dates are as follows:

Port Everglades Unit #2: Spring of 2005

Port Everglades Unit #1: Fall of 2005

Port Everglades Unit #4: Fall of 2006

Port Everglades Unit #3: Spring of 2007

Q. Is FPL recovering through any other mechanism the costs for the UST Replacement/Removal Project, the LQWS Project or the ESP Technology Project for which it is petitioning for ECRC recovery?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

ENVIRONMENTAL COST RECOVERY COMMISSION FORMS 42-1P THROUGH 42-7P

JANUARY 2004 – DECEMBER 2004 PROJECTIONS

KMD-3
DOCKET NO. 030007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _______
PAGES 1-72

Florida Power & Light Company

Environmental Cost Recovery Clause

Total Jurisdictional Amount to Be Recovered

For the Projected Period

January 2004 to December 2004

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)	2,720,910	1,925,498	879,869	5,526,277
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	4,895,758	3,376,516	0	8,272,274
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	7,616,668	5,302,014	879,869	13,798,551
2	True-up for Estimated Over/(Under) Recovery for the current period January 2003 - December 2003 (FORM 42-1E, Line 4, filed on August 8, 2003)	524,408	264,993	61,533	850,933
3	Final True-up Over/(Under) for the period January 2002 - December 2002 (FORM 42-1A, Line 7, filed on April 1, 2003)	140,497	49,062	15,790	205,349
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2004 - December 2004 (Line 1 - Line 2 - Line 3)	6,951,763	4,987,959	802,546	12,742,269
5a	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.01597)	7,062,783	5,067,617	815,363	12,945,763

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 2004 - December 2004

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	$0	$0	$0	$0	$0	$0	$0
	3a	Continuous Emission Monitoring Systems-O&M	0	0	158,160	0	0	158,160	316,320
	4a	Clean Closure Equivalency-O&M	0	0	0	0	0	0	0
	5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	38,375	38,375	38,375	38,375	38,375	38,375	230,250
	5c	Maintenance of Stationary Above Ground Fuel Storage Tanks-Spill Abatement	0	0	0	0	0	0	0
	8a	Oil Spill Cleanup/Response Equipment-O&M	13,833	13,833	13,833	13,833	13,833	13,833	82,998
	8c	Oil Spill Cleanup/Response Equipment-Revenue	0	0	0	0	0	0	0
	9	Low-Level Radioactive Waste Access Fees-O&M	0	0	0	0	0	0	0
	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	134,205	0	0	0	0	0	134,205
	17a	Disposal of Noncontainerized Liquid Waste-O&M	0	0	99,000	0	0	90,000	189,000
	19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	162,014	202,965	203,277	32,593	51,331	45,981	698,161
	19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	84,554	110,465	102,527	100,443	49,131	37,181	484,301
	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	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(215,178)
	22	Pipeline Integrity Management	3,334	3,334	3,334	3,334	3,334	3,334	20,004
	23	SPCC - Spill Prevention, Control & Countermeasures	10,000	10,000	15,000	15,000	15,000	65,000	130,000
	26	UST Replacement/Removal	2,500	10,000	25,000	10,000	6,000	8,000	61,500
	27	Lowest Quality Water Source	30,850	30,850	30,850	30,850	30,850	30,850	185,100
2		Total of O&M Activities	$ 401,283	$ 341,440	$ 610,974	$ 166,046	$ 129,472	$ 412,332	$ 2,061,547
3		Recoverable Costs Allocated to Energy	$ (17,321)	$ (15,328)	$ 241,221	$ (16,099)	$ (20,046)	$ 227,194	$ 399,620
4a		Recoverable Costs Allocated to CP Demand	$ 279,933	$ 177,146	$ 189,819	$ 172,895	$ 121,530	$ 162,500	$ 1,103,824
4b		Recoverable Costs Allocated to GCP Demand	$ 138,671	$ 179,622	$ 179,934	$ 9,250	$ 27,988	$ 22,638	$ 558,103
5		Retail Energy Jurisdictional Factor	98 75007%	98 75007%	98 75007%	98 75007%	98 75007%	98 75007%	
6a		Retail CP Demand Jurisdictional Factor	98 84301%	98 84301%	98 84301%	98 84301%	98 84301%	98 84301%	
6b		Retail GCP Demand Jurisdictional Factor	100 00000%	100 00000%	100 00000%	100 00000%	100 00000%	100 00000%	
7		Jurisdictional Energy Recoverable Costs (A)	$ (17,105)	$ (15,137)	$ 238,206	$ (15,898)	$ (19,796)	$ 224,355	$ 394,625
8a		Jurisdictional CP Demand Recoverable Costs (B)	$ 276,695	$ 175,097	$ 187,623	$ 170,895	$ 120,124	$ 160,619	$ 1,091,053
8b		Jurisdictional GCP Demand Recoverable Costs (C)	$ 138,671	$ 179,622	$ 179,934	$ 9,250	$ 27,988	$ 22,638	$ 558,103
9		Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 398,261	$ 339,582	$ 605,763	$ 164,247	$ 128,316	$ 407,612	$ 2,043,781

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 2004 - December 2004

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	$0	$0	$0	$0	$0	$2,061,980	$2,061,980	$2,061,980			$2,061,980
3a Continuous Emission Monitoring Systems-O&M	0	0	158,160	0	0	158,160	316,320	632,640			632,640
4a Clean Closure Equivalency-O&M	0	0	0	0	0	0	0	0	0		0
5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	38,375	38,375	38,375	38,375	38,375	38,375	230,250	460,500	460,500		
5c Maintenance of Stationary Above Ground Fuel Storage Tanks-Spill Abatement	0	0	0	0	0	0	0	0	0		0
8a Oil Spill Cleanup/Response Equipment-O&M	13,833	13,833	13,833	13,833	13,833	13,833	82,998	165,996			165,996
8c Oil Spill Cleanup/Response Equipment-Revenue	0	0	0	0	0	0	0	0	0		0
9 Low-Level Radioactive Waste Access Fees-O&M	0	0	0	0	0	0	0	0	0		0
13 RCRA Corrective Action-O&M	4,167	4,167	4,167	4,167	4,167	4,167	25,002	50,004	50,004		
14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	134,205	134,205		
17a Disposal of Noncontainerized Liquid Waste-O&M	0	0	49,500	16,500	0	33,000	99,000	288,000			288,000
19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	39,881	39,881	39,881	125,769	129,112	87,300	461,824	1,159,985		1,159,985	
19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	44,281	44,281	37,681	42,069	68,112	41,550	277,974	762,275	703,638		58,637
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	25,000	25,000	50,000	50,000	50,000		
NA Amortization of Gains on Sales of Emissions Allowances	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(215,178)	(430,356)			(430,356)
22 Pipeline Integrity Management	3,334	3,334	3,334	3,334	3,334	3,334	20,004	40,008	40,008		
23 SPCC - Spill Prevention, Control & Countermeasures	55,000	55,000	0	0	0	10,000	120,000	250,000	250,000		
26 UST Replacement/Removal	29,550	15,000	5,000	19,000	5,000	13,000	86,550	148,050	148,050		
27 Lowest Quality Water Source	30,850	30,850	30,850	30,850	30,850	30,850	185,100	370,200	370,200		
2 Total of O&M Activities	$ 176,722	$ 162,172	$ 298,232	$ 211,348	$ 235,234	$2,438,000	$ 3,521,708	$ 5,583,255	$ 1,948,036	$ 879,869	$2,755,350
3 Recoverable Costs Allocated to Energy	$ (20,419)	$ (20,419)	$ 186,733	$ (4,090)	$ (18,586)	$2,232,511	$ 2,355,729	$ 2,755,350			
4a Recoverable Costs Allocated to CP Demand	$ 180,603	$ 166,053	$ 94,961	$ 113,012	$ 148,051	$ 141,532	$ 844,213	$ 1,948,036			
4b Recoverable Costs Allocated to GCP Demand	$ 16,538	$ 16,538	$ 16,538	$ 102,426	$ 105,769	$ 63,957	$ 321,766	$ 879,869			
5 Retail Energy Jurisdictional Factor	98 75007%	98 75007%	98 75007%	98 75007%	98 75007%	98 75007%					
6a Retail CP Demand Jurisdictional Factor	98 84301%	98 84301%	98 84301%	98 84301%	98 84301%	98 84301%					
6b Retail GCP Demand Jurisdictional Factor	100.00000%	100 00000%	100 00000%	100 00000%	100 00000%	100 00000%					
7 Jurisdictional Energy Recoverable Costs (A)	$ (20,164)	$ (20,164)	$ 184,399	$ (4,038)	$ (18,354)	$2,204,606	$ 2,326,285	$ 2,720,910			
8a Jurisdictional CP Demand Recoverable Costs (B)	$ 178,514	$ 164,132	$ 93,862	$ 111,704	$ 146,338	$ 139,895	$ 834,445	$ 1,925,498			
8b Jurisdictional GCP Demand Recoverable Costs (C)	$ 16,538	$ 16,538	$ 16,538	$ 102,426	$ 105,769	$ 63,957	$ 321,766	$ 879,869			
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 174,888	$ 160,506	$ 294,799	$ 210,092	$ 233,753	$2,408,458	$ 3,482,496	$ 5,526,277			

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 2004 - December 2004

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	$ 165,858	$ 164,984	$ 164,109	$ 163,234	$ 162,360	$ 161,485	$ 982,030
	3b	Continuous Emission Monitoring Systems-Capital	123,864	123,871	123,338	123,257	123,175	122,640	740,145
	4b	Clean Closure Equivalency-Capital	493	492	490	488	486	484	2,933
	5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	129,314	131,915	131,599	134,080	136,553	136,220	799,681
	7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	272	271	270	269	268	266	1,616
	8b	Oil Spill Cleanup/Response Equipment-Capital	11,656	11,685	11,612	11,804	11,847	11,721	70,325
	10	Relocate Storm Water Runoff-Capital	962	960	958	955	953	950	5,738
	NA	SO2 Allowances-Negative Return on Investment	(11,440)	(11,160)	(10,881)	(10,601)	(10,321)	(10,821)	(65,224)
	12	Scherer Discharge Pipeline-Capital	7,329	7,305	7,281	7,258	7,234	7,210	43,617
	17b	Disposal of Noncontainerized Liquid Waste-Capital	4,014	3,984	3,954	3,924	3,894	3,865	23,635
	20	Wastewater Discharge Elimination &Reuse	21,785	23,468	23,397	23,327	23,256	23,185	138,418
	21	St Lucie Turtle Net	6,999	6,982	6,965	6,947	6,930	6,913	41,736
	22	Pipeline Integrity Management	6,531	8,702	8,683	8,664	8,645	8,627	49,852
	23	SPCC - Spill Prevention, Control & Countermeasures	75,284	96,594	97,993	103,248	108,490	109,837	591,446
	24	Manatee Reburn	5,156	7,886	10,617	15,025	19,434	19,434	77,552
	25	Pt Everglades ESP Technology	11,118	17,672	24,849	33,781	43,870	54,363	185,653
2		Total Investment Projects - Recoverable Costs	$ 559,195	$ 595,611	$ 605,234	$ 625,660	$ 647,074	$ 656,379	$ 3,689,153
3		Recoverable Costs Allocated to Energy	$ 314,913	$ 325,742	$ 334,586	$ 347,847	$ 362,253	$ 370,892	$ 2,056,233
4		Recoverable Costs Allocated to Demand	$ 244,282	$ 269,869	$ 270,648	$ 277,813	$ 284,821	$ 285,487	$ 1,632,920
5		Retail Energy Jurisdictional Factor	98.75007%	98.75007%	98.75007%	98 75007%	98.75007%	98 75007%	
6		Retail Demand Jurisdictional Factor	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	
7		Jurisdictional Energy Recoverable Costs (B)	$ 310,977	$ 321,671	$ 330,404	$ 343,499	$ 357,725	$ 366,256	$ 2,030,532
8		Jurisdictional Demand Recoverable Costs (C)	$ 241,456	$ 266,747	$ 267,517	$ 274,599	$ 281,526	$ 282,184	$ 1,614,029
9		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 552,433	$ 588,418	$ 597,921	$ 618,098	$ 639,251	$ 648,440	$ 3,644,561

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 2004 - December 2004

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	$ 160,611	$ 159,736	$ 158,862	$ 157,987	$ 157,112	$ 156,238	$ 950,546	$ 1,932,576		$ 1,932,576
3b Continuous Emission Monitoring Systems-Capital	122,556	122,037	121,502	121,419	121,335	120,797	729,646	$ 1,469,791		1,469,791
4b Clean Closure Equivalency-Capital	482	480	478	476	474	472	2,862	$ 5,795	5,349	446
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	136,603	136,984	136,647	137,026	137,404	137,063	821,727	$ 1,621,408	1,496,684	124,724
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	265	264	263	262	260	259	1,573	$ 3,189	2,944	245
8b Oil Spill Cleanup/Response Equipment-Capital	11,911	11,900	11,825	12,013	12,001	11,924	71,574	$ 141,899	130,984	10,915
10 Relocate Storm Water Runoff-Capital	948	945	943	940	938	936	5,650	$ 11,388	10,512	876
NA SO2 Allowances-Negative Return on Investment	(11,322)	(11,042)	(10,762)	(10,482)	(10,203)	(9,923)	(63,734)	$ (128,958)		(128,958)
12 Scherer Discharge Pipeline-Capital	7,187	7,163	7,140	7,116	7,092	7,069	42,767	$ 86,384	79,739	6,645
17b Disposal of Noncontainerized Liquid Waste-Capital	3,835	0	0	0	0	0	3,835	$ 27,470	25,357	2,113
20 Wastewater Discharge Elimination &Reuse	23,114	23,044	22,973	22,902	22,831	22,761	137,625	$ 276,043	254,809	21,234
21 St. Lucie Turtle Net	6,896	6,878	6,861	6,844	6,827	6,809	41,115	$ 82,851	76,478	6,373
22 Pipeline Integrity Management	8,608	8,589	8,570	8,551	8,532	8,513	51,363	$ 101,215	93,429	7,786
23 SPCC - Spill Prevention, Control & Countermeasures	115,064	120,279	121,599	126,799	131,986	135,893	751,620	$ 1,343,066	1,239,753	103,313
24 Manatee Reburn	19,434	19,434	30,396	43,542	45,727	70,577	229,110	$ 306,662		306,662
25 Pt. Everglades ESP Technology	68,235	103,654	144,864	172,329	197,297	220,952	907,331	$ 1,092,984		1,092,984
2 Total Investment Projects - Recoverable Costs	$ 674,427	$ 710,345	$ 762,161	$ 807,724	$ 839,613	$ 890,340	$ 4,684,610	$ 8,373,763	$ 3,416,038	$ 4,957,725
3 Recoverable Costs Allocated to Energy	$ 383,738	$ 418,167	$ 469,270	$ 509,636	$ 536,525	$ 584,156	$ 2,901,492	$ 4,957,725		
4 Recoverable Costs Allocated to Demand	$ 290,689	$ 292,178	$ 292,891	$ 298,088	$ 303,088	$ 306,184	$ 1,783,118	$ 3,416,038		
5 Retail Energy Jurisdictional Factor	98 75007%	98.75007%	98.75007%	98.75007%	98.75007%	98.75007%				
6 Retail Demand Jurisdictional Factor	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%				
7 Jurisdictional Energy Recoverable Costs (B)	$ 378,942	$ 412,940	$ 463,404	$ 503,266	$ 529,819	$ 576,855	$ 2,865,226	$ 4,895,758		
8 Jurisdictional Demand Recoverable Costs (C)	$ 287,326	$ 288,797	$ 289,503	$ 294,639	$ 299,581	$ 302,641	$ 1,762,487	$ 3,376,516		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 666,268	$ 701,737	$ 752,907	$ 797,905	$ 829,400	$ 879,496	$ 4,627,713	$ 8,272,274		

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 2004

Return on Capital Investments, Depreciation and Taxes
For Project Low NOx Burner Technology (Project No 2)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	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)	$17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	n/a
3	Less Accumulated Depreciation (C)	10,664,246	10,776,338	10,888,430	11,000,521	11,112,613	11,224,705	11,336,797	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$6,947,222	$6,835,130	$6,723,038	$6,610,947	$6,498,855	$6,386,763	$6,274,671	n/a
6.	Average Net Investment		6,891,176	6,779,084	6,666,992	6,554,901	6,442,809	6,330,717	
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		40,841	40,177	39,513	38,848	38,184	37,520	235,083
	b Debt Component (Line 6 x 2.2507% x 1/12)		12,925	12,715	12,504	12,294	12,084	11,874	74,396
8	Investment Expenses								
	a. Depreciation (E)		112,092	112,092	112,092	112,092	112,092	112,092	672,551
	b Amortization (F)								
	c Dismantlement								
	d Property Expenses								
	e Other (G)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$165,858	$164,984	$164,109	$163,234	$162,360	$161,485	$982,030

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 33-35.
(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 4 3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No 2)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve 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)	$17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	n/a
3	Less: Accumulated Depreciation (C)	11,336,797	11,448,889	11,560,981	11,673,072	11,785,164	11,897,256	12,009,348	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$6,274,671	$6,162,579	$6,050,487	$5,938,396	$5,826,304	$5,714,212	$5,602,120	n/a
6	Average Net Investment		6,218,625	6,106,533	5,994,442	5,882,350	5,770,258	5,658,166	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		36,855	36,191	35,527	34,862	34,198	33,534	446,250
	b Debt Component (Line 6 x 2.2507% x 1/12)		11,664	11,453	11,243	11,033	10,823	10,612	141,224
8	Investment Expenses								
	a Depreciation (E)		112,092	112,092	112,092	112,092	112,092	112,092	1,345,102
	b Amortization (F)								
	c Dismantlement								
	d Property Expenses								
	e Other (G)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$160,611	$159,736	$158,862	$157,987	$157,112	$156,238	$1,932,576

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 33-35
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project Continuous Emissions Monitoring (Project No 3b)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b Clearings to Plant		$85,500	$0	$0	$69,500	$0	$0	$155,000
	c. Retirements					$0	$0	$0	$0
	d. Other (A)							$0	$0
2	Plant-In-Service/Depreciation Base (B)	$12,989,169	13,074,669	13,074,669	13,074,669	13,144,169	13,144,169	13,144,169	0
3	Less: Accumulated Depreciation (C)	5,557,303	5,625,401	5,693,703	5,762,006	5,830,490	5,899,157	5,967,824	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$7,431,866	$7,449,268	$7,380,966	$7,312,663	$7,313,679	$7,245,012	$7,176,345	n/a
6	Average Net Investment		7,440,567	7,415,117	7,346,815	7,313,171	7,279,345	7,210,679	
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		44,097	43,946	43,542	43,342	43,142	42,735	260,804
	b. Debt Component (Line 6 x 2 2507% x 1/12)		13,955	13,908	13,780	13,716	13,653	13,524	82,536
8	Investment Expenses								
	a Depreciation (E)		68,098	68,303	68,303	68,485	68,667	68,667	410,521
	b. Amortization (F)								
	c. Dismantlement								
	d Property Expenses								
	e. Other (G)		(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(13,716)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$123,864	$123,871	$123,338	$123,257	$123,175	$122,640	$740,145

Notes:

(A) Cost of removal in June 2003
(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 33-35
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(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 July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project Continuous Emissions Monitoring (Project No 3b)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a Expenditures/Additions								
	b Clearings to Plant		$69,500	$0	$0	$69,500	$0	$0	$294,000
	c Retirements			$38,827					$38,827
	d Other (A)								$0
2	Plant-In-Service/Depreciation Base (B)	$13,144,169	13,213,669	13,174,842	13,174,842	13,244,342	13,244,342	13,244,342	n/a
3.	Less Accumulated Depreciation (C)	5,967,824	6,036,672	6,066,440	6,135,034	6,203,811	6,272,769	6,341,727	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$7,176,345	$7,176,997	$7,108,402	$7,039,808	$7,040,532	$6,971,573	$6,902,615	n/a
6	Average Net Investment		7,176,671	7,142,700	7,074,105	7,040,170	7,006,052	6,937,094	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		42,533	42,332	41,925	41,724	41,522	41,113	511,955
	b Debt Component (Line 6 x 2 2507% x 1/12)		13,460	13,397	13,268	13,204	13,140	13,011	162,018
8	Investment Expenses								
	a. Depreciation (E)		68,849	68,594	68,594	68,776	68,958	68,958	823,251
	b Amortization (F)								
	c Dismantlement								
	d Property Expenses								
	e. Other (G)		(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(27,432)
9	Total System Recoverable Expenses (Lines 7 & 8)		$122,556	$122,037	$121,502	$121,419	$121,335	$120,797	$1,469,791

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 33-35
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35
(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 2004

Return on Capital Investments, Depreciation and Taxes
For Project Clean Closure Equivalency (Project No 4b)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	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)	26,814	27,058	27,303	27,547	27,791	28,036	28,280	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$32,052	$31,808	$31,563	$31,319	$31,075	$30,830	$30,586	n/a
6.	Average Net Investment		31,930	31,686	31,441	31,197	30,953	30,708	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		189	188	186	185	183	182	1,114
	b Debt Component (Line 6 x 2 2507% x 1/12)		60	59	59	59	58	58	352
8.	Investment Expenses								
	a Depreciation (E)		244	244	244	244	244	244	1,466
	b. Amortization (F)								
	c Dismantlement								
	d Property Expenses								
	e Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$493	$492	$490	$488	$486	$484	$2,933

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 33-35
(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 4.3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No 4b)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve 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)	28,280	28,524	28,769	29,013	29,257	29,502	29,746	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$30,586	$30,342	$30,097	$29,853	$29,609	$29,364	$29,120	n/a
6	Average Net Investment		30,464	30,220	29,975	29,731	29,487	29,242	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		181	179	178	176	175	173	2,175
	b Debt Component (Line 6 x 2.2507% x 1/12)		57	57	56	56	55	55	688
8	Investment Expenses								
	a. Depreciation (E)		244	244	244	244	244	244	2,932
	b Amortization (F)								
	c. Dismantlement								
	d Property Expenses								
	e. Other (G)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$482	$480	$478	$476	$474	$472	$5,795

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 33-35.
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$508,290			$450,000			$958,290
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,931,422	13,439,712	13,439,712	13,439,712	13,889,712	13,889,712	13,889,712	n/a
3.	Less: Accumulated Depreciation (C)	1,672,418	1,712,059	1,752,631	1,793,204	1,834,822	1,877,487	1,920,151	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,259,004	$11,727,653	$11,687,081	$11,646,508	$12,054,890	$12,012,225	$11,969,561	n/a
6.	Average Net Investment		11,493,328	11,707,367	11,666,795	11,850,699	12,033,558	11,990,893	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		68,116	69,385	69,144	70,234	71,318	71,065	419,264
	b. Debt Component (Line 6 x 2 2507% x 1/12)		21,557	21,958	21,882	22,227	22,570	22,490	132,684
8	Investment Expenses								
	a Depreciation (E)		39,641	40,572	40,572	41,618	42,665	42,665	247,733
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$129,314	$131,915	$131,599	$134,080	$136,553	$136,220	$799,681

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 42-4P, pages 33-35.
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$120,000	$0	$0	$120,000	$0	$0	$1,198,290
	c Retirements								
	d Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,889,712	14,009,712	14,009,712	14,009,712	14,129,712	14,129,712	14,129,712	n/a
3.	Less: Accumulated Depreciation (C)	1,920,151	1,963,065	2,006,227	2,049,389	2,092,800	2,136,459	2,180,119	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,969,561	$12,046,647	$12,003,485	$11,960,323	$12,036,912	$11,993,253	$11,949,593	n/a
6.	Average Net Investment		12,008,104	12,025,066	11,981,904	11,998,618	12,015,082	11,971,423	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		71,167	71,268	71,012	71,111	71,209	70,950	845,980
	b. Debt Component (Line 6 x 2.2507% x 1/12)		22,522	22,554	22,473	22,504	22,535	22,453	267,726
8.	Investment Expenses								
	a. Depreciation (E)		42,913	43,162	43,162	43,411	43,660	43,660	507,701
	b. Amortization (F)								
	c. Dismantlement								
	d Property Expenses								
	e. Other (G)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$136,603	$136,984	$136,647	$137,026	$137,404	$137,063	$1,621,408

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 33-35.
(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 4.3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	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)	15,595	15,748	15,900	16,053	16,205	16,358	16,510	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$15,435	$15,282	$15,130	$14,977	$14,825	$14,672	$14,520	n/a
6	Average Net Investment		15,359	15,206	15,054	14,901	14,748	14,596	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		91	90	89	88	87	87	533
	b. Debt Component (Line 6 x 2 2507% x 1/12)		29	29	28	28	28	27	169
8	Investment Expenses								
	a Depreciation (E)		153	153	153	153	153	153	915
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$272	$271	$270	$269	$268	$266	$1,616

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 33-35
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve 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)	16,510	16,663	16,815	16,968	17,121	17,273	17,426	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,520	$14,367	$14,215	$14,062	$13,909	$13,757	$13,604	n/a
6	Average Net Investment		14,443	14,291	14,138	13,986	13,833	13,681	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		86	85	84	83	82	81	1,033
	b. Debt Component (Line 6 x 2 2507% x 1/12)		27	27	27	26	26	26	327
8	Investment Expenses								
	a Depreciation (E)		153	153	153	153	153	153	1,831
	b Amortization (F)								
	c Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$265	$264	$263	$262	$260	$259	$3,189

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 33-35
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
a.	Expenditures/Additions								
b	Clearings to Plant		$25,954	$0	$0	$16,750	$0	$0	$42,704
c	Retirements								
d	Other (A)								
2	Plant-In-Service/Depreciation Base (B)	$764,665	790,619	790,619	790,619	807,369	807,369	807,369	n/a
3.	Less Accumulated Depreciation (C)	470,269	479,563	488,858	498,152	507,646	517,191	526,685	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$294,396	$311,056	$301,761	$292,467	$299,723	$290,178	$280,684	n/a
6.	Average Net Investment		302,726	306,409	297,114	296,095	294,950	285,431	
7.	Return on Average Net Investment								
a	Equity Component grossed up for taxes (D)		1,794	1,816	1,761	1,755	1,748	1,692	10,566
b	Debt Component (Line 6 x 2.2507% x 1/12)		568	575	557	555	553	535	3,344
8	Investment Expenses								
a.	Depreciation (E)		9,294	9,294	9,294	9,494	9,546	9,494	56,416
b.	Amortization (F)								
c.	Dismantlement								
d	Property Expenses								
e	Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,656	$11,685	$11,612	$11,804	$11,847	$11,721	$70,325

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 33-35.
(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 4.3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a Expenditures/Additions								
	b Clearings to Plant		$16,750	$0	$0	$16,750	$0	$0	$76,204
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base (B)	$807,369	824,119	824,119	824,119	840,869	840,869	840,869	n/a
3	Less: Accumulated Depreciation (C)	526,685	536,378	546,071	555,764	565,657	575,549	585,442	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$280,684	$287,741	$278,048	$268,355	$275,212	$265,320	$255,427	n/a
6.	Average Net Investment		284,212	282,894	273,201	271,783	270,266	260,373	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		1,684	1,677	1,619	1,611	1,602	1,543	20,301
	b Debt Component (Line 6 x 2 2507% x 1/12)		533	531	512	510	507	488	6,425
8	Investment Expenses								
	a. Depreciation (E)		9,693	9,693	9,693	9,893	9,893	9,893	115,173
	b Amortization (F)								
	c Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,911	$11,900	$11,825	$12,013	$12,001	$11,924	$141,899

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 33-35.
(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 4.3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project. Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	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)	34,536	34,850	35,164	35,478	35,792	36,107	36,421	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$83,258	$82,944	$82,630	$82,316	$82,002	$81,687	$81,373	n/a
6.	Average Net Investment		83,101	82,787	82,473	82,159	81,845	81,530	
7.	Return on Average Net Investment								
a	Equity Component grossed up for taxes (D)		493	491	489	487	485	483	2,927
b	Debt Component (Line 6 x 2.2507% x 1/12)		156	155	155	154	154	153	926
8.	Investment Expenses								
a	Depreciation (E)		314	314	314	314	314	314	1,885
b.	Amortization (F)								
c	Dismantlement								
d.	Property Expenses								
e.	Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$962	$960	$958	$955	$953	$950	$5,738

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 33-35
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No 10)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve 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)	36,421	36,735	37,049	37,363	37,677	37,991	38,305	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$81,373	$81,059	$80,745	$80,431	$80,117	$79,803	$79,489	n/a
6.	Average Net Investment		81,216	80,902	80,588	80,274	79,960	79,646	
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		481	479	478	476	474	472	5,787
	b. Debt Component (Line 6 x 2.2507% x 1/12)		152	152	151	151	150	149	1,831
8.	Investment Expenses								
	a. Depreciation (E)		314	314	314	314	314	314	3,769
	b Amortization (F)								
	c Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$948	$945	$943	$940	$938	$936	$11,388

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 33-35.
(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 4.3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project Scherer Discharge Pipeline (Project No 12)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	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)	311,655	314,684	317,713	320,742	323,771	326,800	329,828	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$552,605	$549,576	$546,547	$543,518	$540,489	$537,460	$534,432	n/a
6	Average Net Investment		551,091	548,062	545,033	542,004	538,975	535,946	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		3,266	3,248	3,230	3,212	3,194	3,176	19,327
	b Debt Component (Line 6 x 2.2507% x 1/12)		1,034	1,028	1,022	1,017	1,011	1,005	6,116
8	Investment Expenses								
	a. Depreciation (E)		3,029	3,029	3,029	3,029	3,029	3,029	18,173
	b Amortization (F)								
	c Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,329	$7,305	$7,281	$7,258	$7,234	$7,210	$43,617

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 33-35.
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project. Scherer Discharge Pipeline (Project No 12)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve 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)	329,828	332,857	335,886	338,915	341,944	344,973	348,002	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$534,432	$531,403	$528,374	$525,345	$522,316	$519,287	$516,258	n/a
6	Average Net Investment		532,917	529,888	526,859	523,830	520,802	517,773	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		3,158	3,140	3,122	3,105	3,087	3,069	38,008
	b. Debt Component (Line 6 x 2 2507% x 1/12)		1,000	994	988	982	977	971	12,028
8	Investment Expenses								
	a Depreciation (E)		3,029	3,029	3,029	3,029	3,029	3,029	36,347
	b Amortization (F)								
	c Dismantlement								
	d Property Expenses								
	e Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,187	$7,163	$7,140	$7,116	$7,092	$7,069	$86,384

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 33-35
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No 17)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	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)	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3.	Less Accumulated Depreciation (C)	284,269	288,089	291,909	295,729	299,549	303,369	307,189	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$26,740	$22,920	$19,100	$15,280	$11,460	$7,640	$3,820	n/a
6	Average Net Investment		24,830	21,010	17,190	13,370	9,550	5,730	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		147	125	102	79	57	34	543
	b. Debt Component (Line 6 x 2 2507% x 1/12)		47	39	32	25	18	11	172
8	Investment Expenses								
	a. Depreciation (E)		3,820	3,820	3,820	3,820	3,820	3,820	22,920
	b Amortization (F)								
	c Dismantlement								
	d Property Expenses								
	e. Other (G)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$4,014	$3,984	$3,954	$3,924	$3,894	$3,865	$23,635

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 33-35.
(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 4 3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project. Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve 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)	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3	Less: Accumulated Depreciation (C)	307,189	311,009	311,009	311,009	311,009	311,009	311,009	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,820	$0	$0	$0	$0	$0	$0	n/a
6	Average Net Investment		1,910	0	0	0	0	0	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		11	0	0	0	0	0	555
	b. Debt Component (Line 6 x 2 2507% x 1/12)		4	0	0	0	0	0	176
8.	Investment Expenses								
	a. Depreciation (E)		3,820	0	0	0	0	0	26,740
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$3,835	$0	$0	$0	$0	$0	$27,470

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 33-35
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project. Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a Expenditures/Additions								
	b Clearings to Plant		$300,583	$0	$0	$0	$0	$0	$300,583
	c Retirements								
	d. Other (A)								
2	Plant-In-Service/Depreciation Base (B)	$1,864,578	2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	n/a
3	Less Accumulated Depreciation (C)	305,981	314,466	323,530	332,594	341,658	350,722	359,785	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$1,558,597	$1,850,695	$1,841,631	$1,832,567	$1,823,503	$1,814,440	$1,805,376	n/a
6.	Average Net Investment		1,704,646	1,846,163	1,837,099	1,828,035	1,818,971	1,809,908	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		10,103	10,941	10,888	10,834	10,780	10,727	64,273
	b. Debt Component (Line 6 x 2 2507% x 1/12)		3,197	3,463	3,446	3,429	3,412	3,395	20,340
8.	Investment Expenses								
	a Depreciation (E)		8,485	9,064	9,064	9,064	9,064	9,064	53,804
	b Amortization (F)								
	c. Dismantlement								
	d Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$21,785	$23,468	$23,397	$23,327	$23,256	$23,185	$138,418

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 33-35.
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project, Wasterwater/Stormwater Reuse (Project No 20)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1	Investments								
	a. Expenditures/Additions								
	b Clearings to Plant		$0	$0	$0	$0	$0	$0	$300,583
	c Retirements								
	d. Other (A)								
2	Plant-In-Service/Depreciation Base (B)	$2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	n/a
3.	Less· Accumulated Depreciation (C)	$359,785	368,849	377,913	386,977	396,041	405,105	414,168	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$1,805,376	$1,796,312	$1,787,248	$1,778,184	$1,769,120	$1,760,056	$1,750,993	n/a
6.	Average Net Investment		1,800,844	1,791,780	1,782,716	1,773,652	1,764,588	1,755,525	
7	Return on Average Net Investment								
	Equity Component grossed up for taxes (D)		10,673	10,619	10,565	10,512	10,458	10,404	127,505
	Debt Component (Line 6 x 2 2507% x 1/12)		3,378	3,361	3,344	3,327	3,310	3,293	40,351
8.	Investment Expenses								
	a. Depreciation (E)		9,064	9,064	9,064	9,064	9,064	9,064	108,187
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$23,114	$23,044	$22,973	$22,902	$22,831	$22,761	$276,043

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 33-35
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project Turtle Nets (Project No 21)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	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)	27,532	29,742	31,952	34,162	36,372	38,583	40,793	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$801,257	$799,047	$796,837	$794,627	$792,417	$790,207	$787,996	n/a
6	Average Net Investment		800,152	797,942	795,732	793,522	791,312	789,101	
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		4,742	4,729	4,716	4,703	4,690	4,677	28,257
	b Debt Component (Line 6 x 2 2507% x 1/12)		1,501	1,497	1,492	1,488	1,484	1,480	8,942
8.	Investment Expenses								
	a. Depreciation (E)		2,210	2,210	2,210	2,210	2,210	2,210	13,261
	b. Amortization (F)								
	c. Dismantlement								
	d Property Expenses								
	e. Other (G)		(1,454)	(1,454)	(1,454)	(1,454)	(1,454)	(1,454)	(8,724)
9	Total System Recoverable Expenses (Lines 7 & 8)		$6,999	$6,982	$6,965	$6,947	$6,930	$6,913	$41,736

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 33-35.
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35.
(G) Depreciation offset for base rate items

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project. Turtle Nets (Project No 21)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve 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)	$40,793	43,003	45,213	47,423	49,633	51,843	54,053	n/a
4	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$787,996	$785,786	$783,576	$781,366	$779,156	$776,946	$774,736	n/a
6	Average Net Investment		786,891	784,681	782,471	780,261	778,051	775,841	
7	Return on Average Net Investment								
a	Equity Component grossed up for taxes (D)		4,664	4,650	4,637	4,624	4,611	4,598	56,042
b.	Debt Component (Line 6 x 2.2507% x 1/12)		1,476	1,472	1,468	1,463	1,459	1,455	17,735
8	Investment Expenses								
a	Depreciation (E)		2,210	2,210	2,210	2,210	2,210	2,210	26,521
b	Amortization (F)								
c	Dismantlement								
d	Property Expenses								
e	Other (G)		(1,454)	(1,454)	(1,454)	(1,454)	(1,454)	(1,454)	(17,448)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,896	$6,878	$6,861	$6,844	$6,827	$6,809	$82,851

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 33-35
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35
(G) Depreciation offset for base rate items

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$405,000	$0	$0	$0	$0	$0	$405,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$405,000	810,000	810,000	810,000	810,000	810,000	810,000	n/a
3.	Less: Accumulated Depreciation (C)	3,038	4,860	7,290	9,720	12,150	14,580	17,010	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$401,962	$805,140	$802,710	$800,280	$797,850	$795,420	$792,990	n/a
6.	Average Net Investment		603,551	803,925	801,495	799,065	796,635	794,205	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,577	4,765	4,750	4,736	4,721	4,707	27,256
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,132	1,508	1,503	1,499	1,494	1,490	8,626
8	Investment Expenses								
	a. Depreciation (E)		1,822	2,430	2,430	2,430	2,430	2,430	13,972
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,531	$8,702	$8,683	$8,664	$8,645	$8,627	$49,852

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 33-35.
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project. Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$405,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$810,000	810,000	810,000	810,000	810,000	810,000	810,000	n/a
3	Less: Accumulated Depreciation (C)	$17,010	19,440	21,870	24,300	26,730	29,160	31,590	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$792,990	$790,560	$788,130	$785,700	$783,270	$780,840	$778,410	n/a
6.	Average Net Investment		791,775	789,345	786,915	784,485	782,055	779,625	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		4,693	4,678	4,664	4,649	4,635	4,621	55,195
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,485	1,480	1,476	1,471	1,467	1,462	17,467
8.	Investment Expenses								
	a. Depreciation (E)		2,430	2,430	2,430	2,430	2,430	2,430	28,552
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,608	$8,589	$8,570	$8,551	$8,532	$8,513	$101,215

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 33-35.
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1	Investments								
	a Expenditures/Additions								
	b Clearings to Plant		$3,566,277	$172,000	$167,000	$829,500	$167,000	$167,000	$5,068,777
	c Retirements								
	d Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$4,978,601	8,544,878	8,716,878	8,883,878	9,713,378	9,880,378	10,047,378	n/a
3	Less. Accumulated Depreciation (C)	44,500	67,464	97,362	127,570	159,387	192,814	226,547	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$4,934,101	$8,477,414	$8,619,516	$8,756,308	$9,553,991	$9,687,564	$9,820,831	n/a
6.	Average Net Investment		6,705,757	8,548,465	8,687,912	9,155,150	9,620,778	9,754,198	
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		39,742	50,663	51,490	54,259	57,019	57,809	310,982
	b Debt Component (Line 6 x 2 2507% x 1/12)		12,577	16,033	16,295	17,171	18,045	18,295	98,416
8	Investment Expenses								
	a Depreciation (E)		22,964	29,897	30,208	31,817	33,427	33,733	182,047
	b Amortization (F)								
	c Dismantlement								
	d. Property Expenses								
	e Other (G)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$75,284	$96,594	$97,993	$103,248	$108,490	$109,837	$591,446

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 33-35.
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1	Investments								
	a Expenditures/Additions								
	b Clearings to Plant		$829,500	$167,000	$167,000	$829,500	$167,000	$667,000	$7,895,777
	c Retirements								
	d. Other (A)								
2	Plant-In-Service/Depreciation Base (B)	$10,047,378	10,876,878	11,043,878	11,210,878	12,040,378	12,207,378	12,874,378	n/a
3	Less. Accumulated Depreciation (C)	$226,547	261,889	298,841	336,099	374,966	415,443	456,893	n/a
4	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$9,820,831	$10,614,989	$10,745,037	$10,874,779	$11,665,412	$11,791,935	$12,417,485	n/a
6	Average Net Investment		10,217,910	10,680,013	10,809,908	11,270,095	11,728,673	12,104,710	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		60,558	63,296	64,066	66,793	69,511	71,740	706,947
	b Debt Component (Line 6 x 2.2507% x 1/12)		19,165	20,031	20,275	21,138	21,998	22,703	223,726
8.	Investment Expenses								
	a. Depreciation (E)		35,342	36,952	37,258	38,867	40,477	41,450	412,393
	b Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$115,064	$120,279	$121,599	$126,799	$131,986	$135,893	$1,343,066

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 33-35.
(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 4 3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s) See Form 42-4P, pages 33-35
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	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	(1,484,209)	(1,448,346)	(1,412,483)	(1,376,620)	(1,340,757)	(1,304,894)	(1,469,031)	
2	Total Working Capital	($1,484,209)	($1,448,346)	($1,412,483)	($1,376,620)	($1,340,757)	($1,304,894)	($1,469,031)	
3	Average Net Working Capital Balance		(1,466,278)	(1,430,415)	(1,394,552)	(1,358,689)	(1,322,826)	(1,386,963)	
4	Return on Average Net Working Capital Balance								
	a Equity Component grossed up for taxes (A)		(8,690)	(8,478)	(8,265)	(8,052)	(7,840)	(8,220)	(49,545)
	b Debt Component (Line 6 x 2.2507% x 1/12)		(2,750)	(2,683)	(2,616)	(2,548)	(2,481)	(2,601)	(15,679)
5	Total Return Component		($11,440)	($11,160)	($10,881)	($10,601)	($10,321)	($10,821)	($65,224) (D)
6	Expense Dr (Cr)								
	a 411.800 Gains from Dispositions of Allowances		(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(215,178)
	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)		($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($215,178) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(47,303)	(47,023)	(46,744)	(46,464)	(46,184)	(46,684)	
	a Recoverable Costs Allocated to Energy		(47,303)	(47,023)	(46,744)	(46,464)	(46,184)	(46,684)	
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.53755%	98.53755%	98 53755%	98.53755%	98 53755%	98.53755%	
10	Demand Jurisdictional Factor		97.87297%	97 87297%	97 87297%	97 87297%	97 87297%	97.87297%	
11	Retail Energy-Related Recoverable Costs (B)		(46,611)	(46,336)	(46,060)	(45,784)	(45,509)	(46,002)	(276,301)
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($46,611)	($46,336)	($46,060)	($45,784)	($45,509)	($46,002)	($276,301)

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 4.3685% 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 2004

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	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	(1,469,031)	(1,433,169)	(1,397,306)	(1,361,444)	(1,325,581)	(1,289,719)	(1,253,856)		
2	Total Working Capital	($1,469,031)	($1,433,169)	($1,397,306)	($1,361,444)	($1,325,581)	($1,289,719)	($1,253,856)		
3	Average Net Working Capital Balance		(1,451,100)	(1,415,237)	(1,379,375)	(1,343,512)	(1,307,650)	(1,271,787)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(8,600)	(8,388)	(8,175)	(7,962)	(7,750)	(7,537)	(97,957)	
b	Debt Component (Line 6 x 2 2507% x 1/12)		(2,722)	(2,654)	(2,587)	(2,520)	(2,453)	(2,385)	(31,000)	
5	Total Return Component		($11,322)	($11,042)	($10,762)	($10,482)	($10,203)	($9,923)	($128,958)	(D)
6	Expense Dr (Cr)									
a	411 800 Gains from Dispositions of Allowances		(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(430,353)	
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)		($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($430,353)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($47,184)	($46,904)	($46,625)	($46,345)	($46,065)	($45,785)		
a	Recoverable Costs Allocated to Energy		(47,184)	(46,904)	(46,625)	(46,345)	(46,065)	(45,785)		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98 53755%	98.53755%	98.53755%	98 53755%	98 53755%	98 53755%		
10	Demand Jurisdictional Factor		97 87297%	97 87297%	97 87297%	97 87297%	97 87297%	97 87297%		
11	Retail Energy-Related Recoverable Costs (B)		(46,494)	(46,218)	(45,943)	(45,667)	(45,391)	(45,116)	(551,131)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($46,494)	($46,218)	($45,943)	($45,667)	($45,391)	($45,116)	($551,131)	

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 4 3685% 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 January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No 24)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1	Investments								
	a. Expenditures/Additions		$0	$700,000	$0	$1,130,000	$0	$0	$1,830,000
	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	$660,800	660,800	1,360,800	1,360,800	2,490,800	2,490,800	2,490,800	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$660,800	$660,800	$1,360,800	$1,360,800	$2,490,800	$2,490,800	$2,490,800	n/a
6	Average Net Investment		660,800	1,010,800	1,360,800	1,925,800	2,490,800	2,490,800	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		3,916	5,991	8,065	11,413	14,762	14,762	58,909
	b. Debt Component (Line 6 x 2 2507% x 1/12)		1,239	1,896	2,552	3,612	4,672	4,672	18,643
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)		$5,156	$7,886	$10,617	$15,025	$19,434	$19,434	$77,552

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 42-8P, pages 33-35
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates See Form 42-8P, pages 33-35
(F) Applicable amortization period(s) See Form 42-8P, pages 33-35
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No 24)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$2,810,000	$560,000	$0	$6,370,000	$11,570,000
	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	$2,490,800	2,490,800	2,490,800	5,300,800	5,860,800	5,860,800	12,230,800	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,490,800	$2,490,800	$2,490,800	$5,300,800	$5,860,800	$5,860,800	$12,230,800	n/a
6	Average Net Investment		2,490,800	2,490,800	3,895,800	5,580,800	5,860,800	9,045,800	
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		14,762	14,762	23,089	33,075	34,735	53,611	232,943
	b. Debt Component (Line 6 x 2.2507% x 1/12)		4,672	4,672	7,307	10,467	10,992	16,966	73,719
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)		$19,434	$19,434	$30,396	$43,542	$45,727	$70,577	$306,662

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 42-8P, pages 33-35.
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates See Form 42-8P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2004

Return on Capital Investments, Depreciation and Taxes
For Project ESP (Project No 25)
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1	Investments								
	a Expenditures/Additions		$913,659	$766,500	$1,073,100	$1,216,500	$1,369,800	$1,319,800	$6,659,359
	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	$968,141	1,881,800	2,648,300	3,721,400	4,937,900	6,307,700	7,627,500	n/a
5	Net Investment (Lines 2 - 3 + 4)	$968,141	$1,881,800	$2,648,300	$3,721,400	$4,937,900	$6,307,700	$7,627,500	n/a
6	Average Net Investment		1,424,971	2,265,050	3,184,850	4,329,650	5,622,800	6,967,600	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		8,445	13,424	18,875	25,660	33,324	41,294	141,023
	b Debt Component (Line 6 x 2 2507% x 1/12)		2,673	4,248	5,973	8,121	10,546	13,068	44,629
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)		$11,118	$17,672	$24,849	$33,781	$43,870	$54,363	$185,653

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 42-8P, pages 33-35
(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 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates See Form 42-8P, pages 33-35
(F) Applicable amortization period(s) See Form 42-8P, pages 33-35
(G) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2004

Return on Capital Investments, Depreciation and Taxes
For Project ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1	Investments								
	a Expenditures/Additions		$2,236,134	$6,843,328	$3,720,180	$3,320,180	$3,080,180	$2,983,580	$28,842,941
	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	$7,627,500	9,863,634	16,706,962	20,427,142	23,747,322	26,827,502	29,811,082	n/a
5	Net Investment (Lines 2 - 3 + 4)	$7,627,500	$9,863,634	$16,706,962	$20,427,142	$23,747,322	$26,827,502	$29,811,082	n/a
6	Average Net Investment		8,745,567	13,285,298	18,567,052	22,087,232	25,287,412	28,319,292	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (D)		51,832	78,737	110,040	130,902	149,868	167,837	830,239
	b Debt Component (Line 6 x 2.2507% x 1/12)		16,403	24,918	34,824	41,426	47,429	53,115	262,744
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)		$68,235	$103,654	$144,864	$172,329	$197,297	$220,952	$1,092,983

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 42-8P, pages 33-35
(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 4 3685% reflects an 11% return on equity
(E) Applicable depreciation rate or rates. See Form 42-8P, pages 33-35
(F) Applicable amortization period(s) See Form 42-8P, pages 33-35
(G) N/A

Totals may not add due to rounding

Project No.	PLANT NAME	FOR 2004 PROJECTED JANUARY PLANT IN SERVICE (BOM)	PROJECTED DECEMBER PLANT IN SERVICE (EOM)
02	RIVIERA UNIT 3	$3,846,591.65	$3,846,591.65
	RIVIERA UNIT 4	$3,272,970.68	$3,272,970.68
	PT EVERGLADES UNIT 1	$2,700,574.97	$2,700,574.97
	PT EVERGLADES UNIT 2	$2,377,900.75	$2,377,900.75
	TURKEY UNIT 1	$2,961,524.84	$2,961,524.84
	TURKEY UNIT 2	$2,451,904.92	$2,451,904.92
	TOTAL FOR PROJECT 2	**$17,611,467.81**	**$17,611,467.81**
4	CAPE CANAVERAL COMMON	$17,254.20	$17,254.20
	PT EVERGLADES COMMON	$19,812.30	$19,812.30
	TURKEY COMMON	$21,799.28	$21,799.28
	TOTAL FOR PROJECT 4	**$58,865.78**	**$58,865.78**
7	ST. LUCIE UNIT 1	$31,030.00	$31,030.00
	TOTAL FOR PROJECT 7	**$31,030.00**	**$31,030.00**
8	MARTIN COMMON	$ 23,107.32	$ 23,107.32
	MARTIN COMMON	$ 657,953.94	$ 734,157.94
	MARTIN COM PPBT	$ 15,228.31	$ 15,228.31
	MARTIN COM PPBT	$ 53,549.84	$ 53,549.84
	CAPE CANAVERAL FT	$ 4,362.96	$ 4,362.96
	SANFORD	$ 5,094.50	$ 5,094.50
	TURKEY COMMON	$ 5,368.46	$ 5,368.46
	TOTAL FOR PROJECT 8	**$764,665.33**	**$840,869.33**
10	ST. LUCIE COMMON	$117,793.83	$117,793.83
	TOTAL FOR PROJECT 10	**$117,793.83**	**$117,793.83**
12	SCHERER COMMON	$9,936.72	$9,936.72
	SCHERER COMMON	$524,872.97	$524,872.97
	SCHERER COMMON	$328,761.62	$328,761.62
	SCHERER COMMON	$689.11	$689.11
	TOTAL FOR PROJECT 12	**$864,260.42**	**$864,260.42**
17	MARTIN EQUIPM YAR	$311,008.58	$311,008.58
	TOTAL FOR PROJECT 17	**$311,008.58**	**$311,008.58**
20	CAPE CANAVERAL COMMON	$831,500.94	$956,500.94
	RIVIERA COMMON	$560,786.81	$560,786.81
	PT EVERGLADES COMMON	$362,290.34	$427,873.34
	MARTIN COMMON	$110,000.00	$220,000.00
	TOTAL FOR PROJECT 20	**$1,864,578.09**	**$2,165,161.09**
21	ST LUCIE COMMON	$828,789.34	$828,789.34
	TOTAL FOR PROJECT 21	**$828,789.34**	**$828,789.34**

PROJECT NO 3 b FOR 2004

PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE/ AMORTIZATION PERIOD	PROJECTED JANUARY PLANT IN SERVICE (BOM)	PROJECTED DECEMBER PLANT IN SERVICE (EOM)
PUTNAM COMMON	341	4.20%	$ 82,857.82	$ 82,857.82
PUTNAM COMMON	343	5.60%	$ 3,138.97	$ 3,138.97
PUTNAM UNIT 1	343	6.00%	$ 346,065.01	$ 366,365.01
PUTNAM UNIT 2	343	6.30%	$ 358,915.31	$ 379,215.31
SANFORD COMMON	312	3.50%	$ 5,168.21	$ 5,168.21
SANFORD UNIT 3	311	2.40%	$ 54,282.08	$ 54,282.08
SANFORD UNIT 3	312	2.40%	$ 158,107.02	$ 173,407.02
SANFORD UNIT 3 RL	312	0.00%	$ 442,603.11	$ 442,603.11
SANFORD UNIT 4 RL	312	0.00%	$ 41,859.48	$ 41,859.48
CAPE CANAVERAL COMMON	311	4.90%	$ 59,227.10	$ 59,227.10
CAPE CANAVERAL COMMON	312	8.50%	$ 8,132.66	$ 8,132.66
CAPE CANAVERAL U1	312	8.80%	$ 502,857.87	$ 513,082.87
CAPE CANAVERAL U2	312	8.30%	$ 519,956.24	$ 530,181.24
MARTIN COM FOSSIL	312	4.60%	$ 10,093.81	$ 10,093.81
MARTIN UNIT 1	311	3.30%	$ 36,810.86	$ 36,810.86
MARTIN UNIT 1	312	4.80%	$ 553,158.17	$ 561,033.17
MARTIN UNIT 2	311	3.30%	$ 36,845.37	$ 36,845.37
MARTIN UNIT 2	312	4.90%	$ 551,568.96	$ 559,443.96
MARTIN UNIT 3	343	5.70%	$ 386,605.43	$ 406,905.43
MARTIN UNIT 4	343	5.50%	$ 380,685.87	$ 400,985.87
RIVIERA COMMON	311	5.20%	$ 60,973.18	$ 60,973.18
RIVIERA COMMON	312	8.90%	$ 8,166.97	$ 8,166.97
RIVIERA UNIT 3	312	8.90%	$ 446,895.32	$ 457,020.32
RIVIERA UNIT 4	312	7.90%	$ 430,924.90	$ 441,049.90
FORT MYERS CT's	343	5.50%	$ 64,167.00	$ 64,167.00
MANATEE COMMON	312	4.60%	$ 9,359.98	$ 9,359.98
MANATEE UNIT 1	311	2.90%	$ 56,430.25	$ 56,430.25
MANATEE UNIT 1	312	4.00%	$ 481,325.93	$ 491,550.93
MANATEE UNIT 2	311	3.00%	$ 56,332.75	$ 56,332.75
MANATEE UNIT 2	312	4.20%	$ 517,425.20	$ 527,650.20
FT LAUDERDALE COMMON	341	5.30%	$ 58,859.79	$ 58,859.79
FT LAUDERDALE U4	343	6.50%	$ 458,222.61	$ 478,472.61
FT LAUDERDALE U5	343	6.60%	$ 466,221.29	$ 486,471.29
PT EVERGLADES COMMON	311	5.80%	$ 127,911.34	$ 127,911.34
PT EVERGLADES COMMON	312	7.70%	$ 19,111.95	$ 19,111.95
PT EVERGLADES UT1	312	6.10%	$ 469,449.32	$ 486,699.32
PT EVERGLADES UT2	312	6.50%	$ 490,902.48	$ 508,152.48
PT EVERGLADES UT3	312	7.80%	$ 503,843.57	$ 506,843.57
PT EVERGLADES UT4	312	8.40%	$ 512,009.55	$ 515,009.55
CUTLER COMMON	311	5.20%	$ 64,883.87	$ 64,883.87
CUTLER COMMON	312	8.80%	$ 6,408.88	$ 6,408.88
CUTLER UNIT 5	312	5.00%	$ 310,051.62	$ 320,126.62
CUTLER UNIT 6	312	5.10%	$ 322,119.14	$ 332,194.14
TURKEY UNIT 1	312	8.80%	$ 554,555.15	$ 564,280.15
TURKEY UNIT 2	312	6.70%	$ 513,659.44	$ 523,384.44
TURKEY COMMON	311	4.30%	$ 59,056.19	$ 59,056.19
TURKEY COMMON	312	6.90%	$ 8,168.05	$ 8,168.05
SJRPP COMMON	311	3.40%	$ 43,193.33	$ 43,193.33
SJRPP COMMON	312	3.70%	$ 66,188.18	$ 66,188.18
SJRPP UNIT 1	312	4.10%	$ 106,814.52	$ 106,814.52
SJRPP UNIT 2	312	4.20%	$ 106,783.43	$ 106,783.43
SCHERER UNIT 4	312	4.50%	$ 537,039.34	$ 537,039.34
POWER RESCOU-JUNO	391	3 yr amort	$ -	$ -
POWER RESCOU-JUNO	394	7 yr amort	$ 38,826.87	$ -
POWER RESCOU-JUNO	395	7 yr amort	$ 473,947.53	$ 473,947.53
TOTAL FOR PROJECT 3			**$ 12,989,168.27**	**$ 13,244,341.40**

FOR 2004

PROJECT NO. 5b

PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE	PROJECTED JANUARY PLANT IN SERVICE (BOM)	PROJECTED DECEMBER PLANT IN SERVICE (EOM)
PUTNAM COMMON	342	4.00%	$ 749,025.94	$ 749,025.94
SANFORD COMMON	311	2.80%	$ -	$ -
SANFORD UNIT 3	311	5.80%	$ 796,754.11	$ 796,754.11
CAPE CANAVERAL COMMON	311	4.90%	$ 268,748.69	$ 268,748.69
CAPE CANAVERAL FT	311	4.90%	$ 632,888.19	$ 632,888 19
MARTIN COM PPBT	311	3.60%	$ 638,132.62	$ 638,132 62
MARTIN COM FOSSIL	311	3.60%	$ 407,224.94	$ 407,224.94
MARTIN COM FOP	311	3.60%	$ 65,092.76	$ 65,092.76
MARTIN UNIT 1	311	3.30%	$ 176,338.83	$ 176,338.83
RIVIERA COMMON	311	5.20%	$ 727,734.38	$ 952,734.38
FORT MYERS COMMON	342	1.20%	$ 33,202.98	$ 33,202.98
FORT MYERS GAS TURBINE	342	1.20%	$ 35,690.67	$ 35,690.67
MANATEE COMMON	311	3.50%	$ 30,323.73	$ 30,323.73
MANATEE COMMON	312	4.60%	$ 174,543.23	$ 309,543.23
PORT MANATEE TERM	311	3.50%	$ 3,006,557.60	$ 3,006,557.60
MANATEE FUEL OIL	311	3.50%	$ 74,382.02	$ 74,382.02
MANATEE UNIT 1	312	4.00%	$ 104,845.35	$ 104,845.35
MANATEE UNIT 2	312	4.20%	$ 127,429.19	$ 127,429.19
FT LAUDERDALE COMMON	342	4.30%	$ 898,110.65	$ 898,110.65
FT LAUDERDALE GTS	342	0.70%	$ 584,290.23	$ 584,290.23
PT EVERGLADES FOT	311	5.80%	$ 1,478,078.22	$ 2,154,078.22
PT EVERGLADES GTU	342	1.40%	$ 1,750,217.58	$ 1,912,507.58
TURKEY COMMON	311	4.30%	$ 87,560.23	$ 87,560.23
TURKEY UNIT 2	311	5.20%	$ 42,158.96	$ 42,158.96
SJRPP COMMON	311	3.40%	$ 42,091.24	$ 42,091.24
TOTAL FOR PROJECT 5			**$ 12,931,422.34**	**$ 14,129,712.34**
MARTIN TERMINAL	311	3.60%	$405,000.00	$ 810,000.00
TOTAL FOR PROJECT 22			**$405,000.00**	**$ 810,000.00**
PUTNAM COMMON	342	4.00%	$ 636,125.00	$ 1,641,886.00
SANFORD COMMON	342	4.50%	$ 30,625.00	$ 67,451.00
CAPE CANAVERAL COMMON	311	4.90%	**$ 71,875.00**	**$ 179,180.00**
RIVIERA COMMON	311	5.20%	$ 66,875.00	$ 165,637.00
FORT MYERS COMMON	342	4.50%	$ 668,375.00	$ 1,729,240.00
FT LAUDERDALE COMMON	342	4.30%	**$ 965,125.00**	**$ 2,533,016.00**
PT EVERGLADES COMMON	311	5.80%	**$ 884,375.00**	**$ 2,314,297.00**
TURKEY COMMON	311	4.30%	$ 26,875.00	$ 57,293.00
ST LUCIE COMMON	321	3.20%	$ -	$ 500,000.00
JUNO OFFICE	390	2.80%	$ 50,000.00	$ 50,000.00
GENERAL OFFICE	390	2.80%	$ 50,000.00	$ 50,000.00
POWER SUPPLY SUBSTATIONS	352/361	2.20%	$ 1,528,351.00	$ 3,586,378.23
TOTAL FOR PROJECT 23			**$ 4,978,601.00**	**$ 12,874,378.23**

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 (SO_2), nitrogen oxides (NO_x) 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 $ 96,000. 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, 2003 to December 31, 2003)
The monthly fees for 2002 emissions at Scherer have been paid and continue to be paid in 2003. 2002 air operating permit fees for the Florida facilities were calculated in January 2003 utilizing 2002 operating information. They were paid to the FDEP in March 2003.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $237,723 or 10.8% lower than previously projected. Permit fees are based on tons of pollutants discharged from the fossil fuel fired power plants. These emissions are proportionate to the amount of time and the type of fuel used at each plant. As a result of the completion of the Fort Myers Plant and Sanford Plant repowerings, less residual oil and more natural gas was burned than expected at these sites. Because natural gas produces fewer emissions than residual oil, permit fees were less than projected.

Project Progress Summary:

The monthly fees for 2002 emissions at Scherer have been paid and continue to be paid in 2003. 2002 air operating permit fees for the Florida facilities were calculated in January 2003 utilizing 2002 operating information. They were paid to the FDEP in March 2003.

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $2,061,980.

Project Title: Continuous Emission Monitoring Systems - 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 SO_2, NO_x and carbon dioxide (CO_2) emissions, as well as volumetric flow and opacity data from affected air pollution sources. FPL has 33 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 and volumetric flow. Periodically, these systems 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 will be an ongoing activity following their installation.

Project Accomplishments:

(January 1, 2003 to December 31, 2003)
Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled. Maintenance has been performed on the analyzers. Calibration gases and CEMS parts have been purchased. Analysis of the fuel oil for sulfur content continues to be performed.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $6,549 or 1.0% lower than previously projected.

Project Progress Summary:

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:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $632,640.

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.

The required base line internal inspections have been completed and the future internal inspections have been scheduled based on the established corrosion rate of the tank bottoms. Future costs will be incurred for required 5 year external inspections and repairs.

Project Accomplishments:

(January 1, 2003 to December 31, 2003)
Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections have been completed for this year and all 2003 tank registration fees have been paid.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $127,177 or 71.0% higher than previously projected. This project includes performing the required repairs identified during a tank inspection. The variance is primarily due to an updated estimate of the costs associated with the required repairs, based on the results of tank inspections.

Project Progress Summary:

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.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $460,500.

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, 2003 to December 31, 2003)
Plan updates have continued to be performed and filed for all sites as required. Routine maintenance of all oil spill equipment has continued throughout the year as well as the performance of spill management drills including a Corporate team drill and deployment drills throughout the system. There has also been training for some team members.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $18,888 or 12.6% higher than previously projected. This variance is primarily due to an increase in the required maintenance and operation of spill boats and corporate spill equipment.

Project Progress Summary:

This is an ongoing project. Each reporting period will include ongoing maintenance of all oil spill equipment in accordance with OPA 90.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $165,996.

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 (RFA's) 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 (SWMU's). FPL may also conduct assessments of human health risk 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, 2003 to December 31, 2003)
EPA and the FDEP have agreed that no further action is required at the Fort Myers 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 oversite. EPA issued a RCRA Section 3013 order for site wide corrective action activities at the Manatee, Sanford, Turkey Point and St. Lucie Power Plants.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $2,498 or 5.0% higher than previously projected.

Project Progress Summary:

This is an ongoing project. The next Visual Site Inspection date is pending. No further action is required at Ft. Myers, Martin Power Plants and Putnam except for some petroleum clean up.

Project Projection:
Estimated project expenditures for the period of January 2004 through December 2004 are expected to be $50,004.

Project Title: NPDES Permit Fees - O & M
Project No. 14
Project Description:

In compliance with State of Florida Rule 62-4.052, Florida Power & Light Company (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. After the first year, annual fees are due and payable to the FDEP by January 15th of each year.

Project Accomplishments:

(January 1, 2003 to December 31, 2003)
The NPDES permit fees were paid to the FDEP during the month of January.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $10,643 or 9.4% higher than previously projected.

Project Progress Summary:

The NPDES permit fees were paid to the FDEP during the month of January.

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $134,205.

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, 2003 to December 31, 2003)
Ash de-watering has been completed at Riviera. Currently processing material at Manatee, which will be completed in August 2003. Ash de-watering is planned for the rest of 2003 at Martin, Turkey Point, and Cape Canaveral.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $39,862 or 14.8% lower than previously projected. This variance is primarily due an increase in the time needed to complete the clean out of the drying basin at the Manatee Plant. The increase in work time at the Manatee Plant has delayed the work scheduled at the Port Everglades plant to 2004.

Project Progress Summary:

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:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $288,000.

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. Additionally, the majority of activities will be conducted in Dade and Broward counties which adhere to county regulations as defined in municipal codes. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation.

Project Accomplishments:

(January 1, 2003 to December 31, 2003)
Plan development started in 1997 and field work is planned to continue through 2003. The majority of the completed work has been in Dade and Broward counties. Regasketing and encapsulation work has started in Palm Beach County and remediation work is being performed throughout the FPL service territory.

A total of 709 transformer locations have been remediated since 1997, this completes the remediation phase of the project. A total of 387 transformers have been regasketed and 789 transformers have been encapsulated.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be:
- 19a $1,000,300 No variance is anticipated
- 19b $677,900 No variance is anticipated
- 19c ($560,232) No variance is anticipated

Personnel resources were reassigned to perform critical system reliability activities. This project was affected by these reliability activities, extending the required work to 2003.

Project Progress Summary:

Remediation phase of the project is complete. The regasketing and encapsulation phase of the project continues.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $1,362,028.

Project Title: Wastewater/Stormwater Discharge Elimination Project
Project 20a

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, 2003 to December 31, 2003)
Work on this project has been completed as follows. The Riviera plant has completed activities totaling approximately $25,000 for the year. The Manatee plant is scheduled to spend approximately $10,000 by the end of 2003. The activities at the Manatee plant are planned to be completed in the 4th quarter of 2003, during a scheduled outage.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $52,389 or 61.6% lower than projected. This variance is primarily due to timing differences. Work that was to be performed at the Port Everglades plant this year has been deferred to 2004.

Project Progress Summary:
During detailed engineering and design, industry research revealed that there is limited information regarding the minimum quality of reuse water needed so as not to adversely affect the performance and/or reliability of the power generating equipment. Furthermore, bench testing at our Putnam Plant to make demineralized water from stormwater proved unsuccessful and the water treatment vendor could not readily suggest a workable alternative to the original proposal. Because of these limitations and unknowns, FPL feels it would be prudent to construct reuse systems on a limited basis and monitor the effects of the reuse water on plant equipment. It is expected that the trial implementation would need to operate for at least two (2) years before accurate conclusions could be drawn regarding acceptable reuse water quality. Accordingly, the majority of the expenditures for field-erected storage tanks and reuse pump & piping systems have been pushed beyond the year 2001.

FPL will continue to work with the FDEP to evaluate the compliance risk associated with its wastewater systems and effect additional future upgrades as necessary.

Project Projections:
Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $50,000.

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 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, 2003 to December 31, 2003)
The final draft of the Pipeline Integrity Management plan was approved and is in force. Plans are underway to solicit bids for the performance of the first of the baseline assessments on the Martin 18" pipeline.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $127,216 or 63.6% lower than projected. The development of the baseline assessment plan required less contractor utilization than originally expected.

Project Progress Summary:

This is an ongoing project. Step two is the baseline assessment plan and it is well on the way. Step three is next which is information analysis and this should begin in January 2004.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $40,008 of O&M.

Project Title: SPCC (spill prevention, control, and countermeasures) – O&M
Project No.23
Project Description:

The SPCC Program was first established by the EPA 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, 2003 to December 31, 2003)
The project is moving toward construction starting in September. The work scope is developed and bids have been solicited. Initial studies to confirm compliance methods are also complete.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $98,739 or 56.4% lower than projected. This variance is primarily due to a change in the implementation date of the SPCC plans from August 2003 to February 2005 by the EPA.

Project Progress Summary:
Initial studies have been completed for the compliance methods that will be used. The EPA changed the implementation dates from August 2003 to February 2005; therefore the schedule has slowed down a little from the initial push.

Project Projections:
Estimated project expenditures for the period January 2004 through December 2004 are expected to be $250,000 of O&M.

Project Title: Reburn NOx Control Technology at Manatee Plant – 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 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, 2003 to December 31, 2003)
The Manatee Reburn project is in its early stages and FPL has put together cost estimates, looked at alternatives for NOx control technology, and worked with the Florida Department of Environmental Protection to reach an agreement to ensure compliance with ozone ambient air quality standards in the Tampa Bay Airshed.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
None

Project Progress Summary:
The engineers are in the process of preparing and reviewing the request for proposals for the Manatee Reburn project.

Project Projections:
Estimated project expenditures for the period January 2004 through December 2004 are expected to be $0 of O&M.

Project Title: Underground Storage Tanks – 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's Category-A is single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.
UST's Category-B is 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's and AST's for Category-C 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. Exhibit RRL- 2 provides a list and description of FPL's existing UST systems.
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, 2003 to December 31, 2003)
Initial review of the scope of work has been completed.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
None

Project Progress Summary:
Initial review of the scope of work has been completed.

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $148,050 of O&M.

Project Title: Lowest Quality Water Source (LQWS) – O&M
Project No.27
Project Description:

Section 366.8255 of the Florida Statutes provides for the recovery through the ECRC of "environmental compliance costs," which are costs incurred in complying with "environmental rules or regulations." As I explain below, 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 and Cape Canaveral Plants. 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 and Cape Canaveral Plants 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 requirement for the Cape Canaveral Plant is found in Conditions 14 and 15 of CUP No. 10652, issued October 2001, which address the quantity of reclaimed water to be used and require that all available reclaimed water be used prior to groundwater.

Project Accomplishments:

(January 1, 2003 to December 31, 2003)
The project at Sanford is currently operational and the project at Cape Canaveral is under construction and should be complete by the end of the year

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures will be $93,000 for O&M.

Project Progress Summary:

(January 2003 - December 2003)
Negotiations have taken place between Brevard County and Cape Canaveral for the purchase of water and negotiations are taking place in regards to the filtration process. The Sanford plant is complete with their negotiations and U.S. Filter if the vendor that was selected for the filtration process.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $370,200 of O&M.

Project Title: Low NO_x Burner Technology (LNBT) – Capital (Florida Facilities)
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, 2003 to December 31, 2003)
All six units are in service and operational.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $2,072,617 no variance anticipated.

Project Progress Summary:

Dade, Broward and Palm Beach Counties have now been redesignated as "attainment" for ozone with air quality maintenance plans. This redesignation 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:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $1,932,576.

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 SO_2, NO_x and carbon dioxide (CO_2) emissions, as well as volumetric flow, heat input, and opacity data from affected air pollution sources. FPL has 36 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, 2003 to December 31, 2003)
NOx Continuos Emission Monitoring Analyzers were installed at all Utility facilities with the exception of Putnam, Martin 3/4 and Lauderdale Plants. These installations will be performed during the 4th quarter of 2003 and will conclude the NOx analyzer portion of the project. Martin Units 1 & 2 NOx installations were performed in mid 2002 as part of a separate project.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)

The variance is \$30,835, or 2.0% lower than projected. The replacement of the CEMS Data Acquisition and Handling System (DAHS) servers and associated software upgrades is currently under review for the best technology and lowest price compliance option. An analysis is being developed based on the current system's recent failures. If the analysis shows that the replacement of the current servers and software upgrades is necessary, these expenses will be incurred in 2004.

Project Progress Summary:

The project is under review for the best technology and lowest price compliance option, for installation in late 2003.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be \$1,469,791.

Project Title: Clean Closure Equivalency Demonstration (CCED) – Capital
Project No. 4b
Project Description:

In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed CCED's 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.

(January 1, 2003 to December 31, 2003)
Project Accomplishments:

No additional wells were installed and the activities are complete.

(January 1, 2003 to December 31, 2003)
Project Fiscal Expenditures:

Project expenditures are estimated to be $6,132, a 0% variance from original projections.

Project Progress Summary:

In September 1995, FPL discontinued CCED activities based on the FDEP's final decision to approve FPL's request for facility status change to generator. The approval was based on FDEP's previous acceptance of FPL's 40 CFR 264 clean closures, which were completed in 1988. Prior to September 1995, monitoring wells were completed at eight of the plants.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $5,795.

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, 2003 to December 31, 2003)
The double bottom has been installed in tank 901 and this job is final. The installation of the double bottom in 902 has started and is progressing on schedule.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
The variance of $126,865 or 7.8% lower than projected is due to delays in the installation of double bottoms in two tanks at the Port Everglades Plant. The delays were due to an increase in the time needed to complete the clean out of the tanks and the welding of side plates. Additionally, the installation of a tank liner at the Riviera Plant that was slated for this year has been deferred to 2004.

Project Progress Summary:

FPL has completed initial inspections and upgrades for all of its tanks. Two of the storage tanks located at the Port Everglades Terminal needed to be retrofitted with new double bottoms because the initial FDEP approved method for double bottom leak detection system used by FPL has failed over the past two years. FPL has obtained alternate procedures from the Florida Department of Environmental Protection to install these double bottom leak detection systems along with additional alarms and valve containment systems for the light oil tanks in lieu of secondary containment dike liners. The alternate procedures may be rescinded by FDEP in the next couple of years.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $1,621,408.

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, 2003 - December 31, 2003)
The piping relocation on Unit 1 was completed in May 1993. Approximately 200 feet of small bore pipe was installed above ground. The Unit 2 piping relocation project was cancelled after a system review. The analysis identified the turbine lube oil piping system as piping associated with a flow through process storage tank system, rendering it exempt from Chapter 17-762 F.A.C. requirements.

Project Fiscal Expenditures:
(January 1, 2003 - December 31, 2003)
Project expenditures are estimated to be $3,391, or a 0% variance.

Project Progress Summary:

This project is complete.

Project Projections:

Estimated project fiscal expenditures (depreciation and return) for the period of January 2004 through December 2004 are expected to be $3,189.

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, 2003 to December 31, 2003)
All equipment is being maintained and replaced according to capital budgeting requirements in order to maintain compliance with regulatory guidelines for response readiness.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
The variance of $32,072 or 19.1% lower than projected is due to Coast Guard Rule OPA-90, part of the Oil Pollution Act, which has been put on hold until further review by the Coast Guard. This rule would have required a 25% increase in oil spill equipment in 2003. The estimated cost of the new equipment is $300,000.

Project Progress Summary:

All deadlines, both state and federal, have been met. Ongoing costs will be annual in nature and will consist of equipment upgrades/replacements.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $141,899.

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, 2003 - December 31, 2003)
The rerouting of the storm water runoff was completed in April 1994.

Project Fiscal Expenditures:
(January 1, 2003 - December 31, 2003)
Project expenditures are estimated to be $11,898 or a 0% variance.

Project Progress Summary:

The rerouting of the storm water runoff project is complete.

Project Projections:

Estimated project fiscal expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $11,388.

Project Title: Scherer Discharge Pipeline – Capital
Project No. 12
Project Description:

On March 16, 1992, pursuant to the provisions of the Georgia Water Quality control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated thereunder, the Georgia Department of Natural Resources issued the National Pollutant Discharge Elimination System (NPDES) permit for Plant Scherer to Georgia Power Company. In addition to the permit, the Department issued Administrative Order EPD-WQ-1855 which provided a schedule for compliance by April 1, 1994 with new facility discharge limitations to Berry Creek. As a result of these new limitations, and pursuant to the order, Georgia Power Company was required to construct an alternate outfall to redirect certain wastewater discharges to the Ocmulgee River. Pursuant to the ownership agreement with Georgia Power Company for Scherer Unit 4, FPL is required to pay for its share of construction of the discharge pipeline which will constitute the alternate outfall.

Project Accomplishments:
(January 1, 2003 - December 31, 2003)
The discharge pipeline was placed in-service in February 1994.

Project Fiscal Expenditures:
(January 1, 2003 - December 31, 2003)
Project expenditures are estimated to be $90,844 or a 0% variance.

Project Progress Summary:

Installation of the discharge pipeline is complete, and it was placed in-service in February 1994.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $86,384.

Project Title: Disposal of Noncontainerized 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 dewatered using a plate frame press to dispose in Class I landfill.

Project Accomplishments:
(January 1, 2003 - December 31, 2003)
The Plate and Frame Press was purchased and outfitted with the associated support equipment, pumps and hardware. The frame press was then placed into service in January 1997.

Project Fiscal Expenditures:
(January 1, 2003 - December 31, 2003)
Project expenditures are estimated to be $50,581 or a 0% variance.

Project Progress Summary:

This project is complete.

Project Projections:

Estimated project fiscal expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $27,470.

Project Title: Wastewater/Stormwater Discharge Elimination Project - Capital
Project 20b
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 2003 - December 2003)
The project at Port Everglades is on hold at this time pending a meeting in September to discuss the ESP project which, is going to affect the water/wastewater situation as a whole for Port Everglades. Martin is installing some upgrades for the boiler blowdown system. Cape Canaveral has deferred their project until 2004 due to timing of outages not allowing a window to do the work scheduled.

Project Fiscal Expenditures:

(January 2003 - December 2003)
Project expenditures are estimated to be $8,843 or 4.3% higher than originally projected. No significant variance is anticipated.

Project Progress Summary:

Developments since our last filing that have resulted in an elongation in the timeframe required to complete the Wastewater/Stormwater Minimization and Reuse Project. During detailed engineering and design, industry research revealed that there is limited information regarding the minimum quality of reuse water needed so as not to adversely affect the performance and/or reliability of the power generating equipment. Because of these limitations and unknowns, FPL feels it would be prudent to construct reuse systems on a limited basis and monitor the effects of the reuse water on plant equipment. It is expected that the trial implementation would need to operate for at least two (2) years before accurate conclusions could be drawn regarding acceptable reuse water quality. Accordingly, the majority of the expenditures for field-erected storage tanks and reuse pump & piping systems have been pushed beyond the year 2001.

FPL will continue to work with the FDEP to evaluate the compliance risk associated with its wastewater systems and effect additional future upgrades as necessary.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $276,043.

Project Title: Turtle Net at St Lucie Nuclear Plant – 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.

Project Accomplishments:

(January 1, 2003 to December 31, 2003)
The Turtle Net Project has been fully completed in November 2002.

Project Fiscal Expenditures:

(January 1, 2003 – December 31, 2003)
The variance of $16,927, or 24.3% higher than projected is primarily due to additional dredging costs. More dredging was required to expose the existing anchor blocks located at the canal bottom and the additional anchoring system was more difficult to install than originally anticipated and, therefore, required more work than expected.

Project Progress Summary:

Complete

Project Projections: Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $82,851.

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, 2003 to December 31, 2003)
This project is in the conceptual design phase and the design should be complete by year-end. Once this is done it will be put out to bid.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
The variance of $54,952 or 83.2% lower than projected is due to delays in vendor selection, which delayed the installation of positive displacement meters on the 30-inch pipeline at the Martin Plant. These installations have been deferred to 2004.

Project Progress Summary:

This is an ongoing project. Step two is the baseline assessment plan and it is well on the way. Step three is next which is information analysis will also include the installation of some equipment at FPL's Martin Plant and this should begin in January 2004.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $101,215 of capital.

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, 2003 to December 31, 2003)
Power Systems has identified 500+ locations (substations and service centers) that will require some form of containment. An Environmental Consulting firm has been hired to design and oversee the construction of the containment, and the competitive bidding process was used to select a vendor to install the containment. Power Generation is moving toward construction starting in September. The work scope is developed and bids have been solicited. Modification work will commence in the near future. The written plan is in the process of being modified as well.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
The variance is estimated to be $81,666 or 33.8% lower than projected, and is primarily due to a change in the implementation date of the SPCC plans from August 2003 to February 2005.

Project Progress Summary:
As of December 31, 2003, containment will be installed at 144 locations.

Project Projections:
Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $1,343,066.

Project Title: Reburn NOx Control Technology at Manatee Plant – 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, 2003 to December 31, 2003)
Bid evaluation of potential Reburn Contractors is complete and a preferred contractor has been selected, pending the results of final negotiations, we are expecting a signed contract by the end of September 2003. If a contract is consummated in September, we would expect process and detail design to be approximately 30% complete by year end. We have expended approximately $110,000 in contracted in-house Reburn related modeling studies.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
None

Project Progress Summary:
The engineers and contractors are in the process of reviewing detail design and should be approximately 30% complete by year-end.

Project Projections:
Estimated project expenditures (return on CWIP) for the period January 2004 through December 2004 are expected to be $306,662.

Project Title: Port 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, 2003 to December 31, 2003)
Anticipate November 2003 approval by the Florida Public Service Commission to proceed with Electrostatic Precipitator project as an ECRC project. The milestone schedule has been developed to support the installation of the electrostatic precipitators during planned unit outages.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are projected to be $968,141, which will occur in the fourth quarter of 2003.

Project Progress Summary:

(January 2003 - December 2003)
The contract for the owner's engineer will be issued in September 2003 with the issuance of the Electrostatic precipitator specification planned for November 2003.

Project Projections:

Estimated project expenditures (return on CWIP) for the period January 2004 through December 2004 are expected to be $1,239,748.

Form 42-6P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2004 to December 2004

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	62 965%	58.416%	53,694,499,279	9,734,788	10,492,790	1.09449148	1.07375594	57,654,787,546	10,654,643	11,484,269	53.28639%	58 10925%	58.02557%
GS1	64.280%	56.924%	6,085,869,172	1,080,793	1,220,452	1.09449148	1.07375594	6,534,738,174	1,182,919	1,335,774	6 03961%	6.45151%	6 74915%
GSD1	74.244%	67.961%	22,784,873,809	3,503,331	3,827,236	1.09438581	1.07367680	24,463,590,399	3,833,996	4,188,473	22.61003%	20.91019%	21.16273%
OS2	63.104%	18.904%	22,034,093	3,986	13,306	1 05884095	1 04655264	23,059,838	4,221	14,089	0.02131%	0 02302%	0.07119%
GSLD1/CS1	79.544%	72.594%	10,444,350,417	1,498,890	1,642,391	1.09287381	1.07253706	11,201,952,890	1,638,098	1,794,926	10.35320%	8.93401%	9.06907%
GSLD2/CS2	83.996%	77.485%	1,721,709,924	233,990	253,653	1.08506569	1.06615414	1,835,608,163	253,895	275,230	1 69653%	1.38472%	1 39063%
GSLD3/CS3	84.848%	0.000%	180,075,156	24,227	0	1.02896017	1.02363751	184,331,684	24,929	0	0 17037%	0 13596%	0 00000%
SST1T	107.912%	0.000%	146,444,940	15,492	0	1.02896017	1.02363751	149,906,534	15,941	0	0.13855%	0.08694%	0.00000%
SST1D	77.366%	64.707%	58,882,752	8,688	10,388	1.06491778	1.05342951	62,028,828	9,252	11,062	0.05733%	0.05046%	0 05589%
CILCD/CILCG	90.386%	83.265%	3,462,136,755	437,259	474,657	1.08267759	1.06493286	3,686,943,196	473,411	513,900	3 40759%	2.58193%	2.59654%
CILCT	96.508%	0.000%	1,591,014,236	188,194	0	1.02896017	1.02363751	1,628,621,851	193,644	0	1.50522%	1.05611%	0.00000%
MET	65.506%	56.001%	93,722,226	16,333	19,105	1.05884095	1.04655264	98,085,243	17,294	20,229	0.09065%	0.09432%	0.10221%
OL1/SL1/PL1	290.896%	47 757%	551,019,353	21,623	131,713	1.09449148	1 07375594	591,660,303	23,666	144,159	0.54683%	0 12907%	0.72838%
SL2	99.875%	99 875%	76,974,890	8,798	8,798	1.09449148	1.07375594	82,652,246	9,629	9,629	0.07639%	0 05252%	0.04865%
TOTAL			100,913,607,000	16,776,392	18,094,489			108,197,966,894	18,335,538	19,791,740	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 2004 through December 2004
(4) Calculated: (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2002 demand losses
(7) Based on 2002 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 2004 to December 2004

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	53.28639%	58.10925%	58.02557%	$3,763,502	$2,944,754	$473,119	$7,181,375	53,694,499,279	0.00013
GS1	6.03961%	6 45151%	6.74915%	$426,565	$326,938	$55,030	$808,533	6,085,869,172	0.00013
GSD1	22.61003%	20.91019%	21.16273%	$1,596,897	$1,059,648	$172,553	$2,829,098	22,784,873,809	0.00012
OS2	0.02131%	0.02302%	0.07119%	$1,505	$1,167	$580	$3,252	22,034,093	0.00015
GSLD1/CS1	10.35320%	8.93401%	9 06907%	$731,224	$452,741	$73,946	$1,257,911	10,444,350,417	0.00012
GSLD2/CS2	1.69653%	1.38472%	1.39063%	$119,822	$70,172	$11,339	$201,333	1,721,709,924	0.00012
GSLD3/CS3	0.17037%	0.13596%	0.00000%	$12,033	$6,890	$0	$18,923	180,075,156	0.00011
SST1T	0.13855%	0.08694%	0 00000%	$9,785	$4,406	$0	$14,191	146,444,940	0.00010
SST1D	0.05733%	0.05046%	0.05589%	$4,049	$2,557	$456	$7,062	58,882,752	0.00012
CILC D/CILC G	3.40759%	2.58193%	2.59654%	$240,671	$130,842	$21,171	$392,684	3,462,136,755	0.00011
CILC T	1.50522%	1.05611%	0.00000%	$106,311	$53,520	$0	$159,831	1,591,014,236	0 00010
MET	0.09065%	0.09432%	0.10221%	$6,403	$4,780	$833	$12,016	93,722,226	0.00013
OL1/SL1/PL1	0.54683%	0 12907%	0.72838%	$38,622	$6,541	$5,939	$51,102	551,019,353	0.00009
SL2	0.07639%	0.05252%	0 04865%	$5,395	$2,661	$397	$8,453	76,974,890	0.00011
TOTAL				$7,062,783	$5,067,617	$815,363	$12,945,763	100,913,607,000	0.00013

Notes: 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 2004 through December 2004
(9) Col 7 / Col 8 x 100

FLORIDA ADMINISTRATIVE CODE – TITLE 62

DEPARTMENT OF ENVIRONMENTAL PROTECTION

CHAPTER 62-761.500

RRL-1
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-17

3. A spill or overfill event of a regulated substance to soil or another pervious surface, equal to or exceeding 25 gallons, unless the regulated substance has a more stringent reporting requirement specified in C.F.R. Title 40, Part 302;

4 Results of analytical or field tests of soil indicating the presence of contamination by:

a. A hazardous substance from a UST system;

b. A regulated substance, other than petroleum products;

c. Petroleum products' chemicals of concern that exceed the lower of direct exposure I and leachability Table V cleanup target levels specified in Table IV in Chapter 62-770, F.A.C., unless due to a spill or overfill event in a quantity less than that described in subparagraph 3. above; or

5. Soils stained by regulated substances that are observed during a closure assessment performed in accordance with Rule 62-761.800(4), F.A.C.

(b) Copies of analytical or field test results that confirm a discharge shall be submitted to the County with Discharge Report Form 62-761.900(1).

(c) A request for a retraction of a submitted Discharge Report Form may be submitted to the County or the Department if evidence is presented that a discharge did not occur at the facility.

(d) A Discharge Report Form 62-761.900(1) does not need to be submitted for previously reported discharges.

Specific Authority 376.303, FS.
Law Implemented 376.303, FS.
History -- New 12-10-90, Formerly 17-761.450, Amended 9-30-96, 7-13-98.

62-761.460 Reporting. (Repealed)

Specific Authority 376.303, FS.
Law Implemented 376.303, FS.
History -- New 12-10-90, Formerly 17-761.450, Repealed 9-30-96.

62-761.480 Financial Responsibility. (Repealed)

Specific Authority 376.303, 376.309, FS.
Law Implemented 376.303, 376.309, FS.
History -- New 12-10-90, Formerly 17-761.480, Repealed 9-30-96.

62-761.500 Performance Standards for Category-C Storage Tank Systems.

(1) General performance standards. AST and UST Category-C systems shall be constructed and installed in accordance with the requirements of this section. AST and UST Category-C systems shall be made of, or internally lined with, materials that are compatible with the regulated substance stored in the system. The following requirements are applicable to both UST and AST systems:

(a) Siting. Persons are advised that, pursuant to Rule 62-521.400(1)(l)-(n) and (2), F.A.C., no storage tank shall be installed within 500 feet of any existing community water supply system or any existing non-transient non-community water supply system. No Category-C system (AST or UST) shall be installed within 100 feet of any other existing potable water supply well. These prohibitions shall not apply to the replacement of an existing storage tank system within the same excavation or dike field area, or the addition of new storage systems meeting the standards for Category-C systems at an existing facility.

(b) Exterior coatings. Exterior portions of aboveground tanks and aboveground integral piping, excluding double-walled systems, shall be coated or otherwise protected from external corrosion. The coating shall be designed and applied to resist corrosion, deterioration, and degradation of the exterior wall. SSPC-PA 1, Paint Application Specification No. 1 may be used to protect storage tank systems from external corrosion.

(c) Spill containment. USTs and shop-fabricated ASTs shall be installed with a spill containment system at each tank fill connection. The spill containment system shall be a fixed component that is designed to prevent a discharge of regulated substances when the transfer hose or pipe is detached from the tank fill pipe. The spill containment system shall meet the requirements of Rule 62-761.500(1)(e), F.A.C.

(d) Dispensing systems.

1. The dispensing system used for transferring fuels from storage tanks shall be installed and maintained in accordance with the provisions of NFPA 30 and Chapters 2, 4 and 9 of NFPA 30A.

2. Dispensers shall be designed, constructed, and maintained to provide access for examination and removal of collected product and accumulated water from dispenser liners.

(e) Secondary containment.

1. The materials used for secondary containment shall be:

a. Impervious to the regulated substance and able to withstand deterioration from external environmental conditions;

b. Non-corrosive or of corrosion-protected materials;

c. Capable of containing regulated substances for at least 30 days; and

d. Of sufficient thickness and strength to withstand hydrostatic forces at maximum capacity to prevent a discharge during its operating life.

2. Liners, unless previously approved by the Department, shall be approved by the Department in accordance with Rule 62-761.850(2), F.A.C. Liners shall not be constructed or consist of naturally occurring in-situ soils.

3. Secondary containment constructed of concrete shall be:

a. Designed and constructed in accordance with ACI 350R-89 and ACI 224R-89; or

b. Lined on the visible interior surfaces of the dike field area in accordance with NACE International Standard RP 0892-92, or SSPC Publication 97-04, Design, Installation, and Maintenance of Coating Systems for Concrete Used in Secondary Containment; or

c. Designed, evaluated, and certified by a professional engineer registered in the State of Florida that the concrete secondary containment system meets the General Construction Requirements specified in Rule 62-761.500(1)(e)1., F.A.C.

4. For cathodically protected tanks and integral piping, secondary containment systems shall not interfere with the operation of the cathodic protection system.

5. Storage tank system equipment with closed interstitial spaces, such as double-walled USTs, double-bottomed ASTs, and double-walled integral piping in contact with the soil that is connected to ASTs or USTs, shall be designed, constructed and installed to allow for the detection of a breach of integrity in the inner or outer wall by the monitoring of the interstitial space in accordance with Rule 62-761.640(3)(a), F.A.C. A breach of integrity test shall be performed before the storage tank system is put into service.

6. Secondary containment systems shall be designed and installed to direct any release to a monitoring point or points.

7. Airport and seaport hydrant pits. Underground hydrant pits shall be installed with a spill catchment basin, secondary containment, or other spill prevention equipment to prevent the discharge of pollutants during fueling of aircraft, vessels, or at any other time the hydrant system is in use. Any such equipment shall be sealed to and around the hydrant piping with an impervious, compatible material.

8. Field-fabricated dispenser liners and piping sumps installed before July 13, 1998 do not have to be approved in accordance with Rule 62-761.850, F.A.C.

(f) Cathodic protection.

1. Test stations. Cathodic protection systems shall be designed, constructed, and installed with at least one test station or method of monitoring to allow for a determination of current operating status. Cathodic protection test stations shall provide direct access to the soil electrolyte in close proximity to each cathodically protected structure for placement of reference electrodes, and monitoring wires that connect directly to cathodically protected structures. Facilities where direct access to soil in close proximity to cathodically protected structures is present, and where electrical connections to cathodically protected structures can be conveniently accomplished, need not have separate dedicated cathodic protection test stations.

2. The cathodic protection system shall be operated and maintained in accordance with Rule 62-761.700(1)(b), F.A.C.

3. Any field-installed cathodic protection system shall be designed by a Corrosion Professional.

(g) Relocation of USTs. Tanks that have been removed and that are to be reinstalled at a different location shall:

1. Be recertified that all original warranties are confirmed by the original manufacturer or the manufacturer's successor, and be reinstalled in accordance with the standards in Rule 62-761.500, F.A.C., that were in effect on July 13, 1998; or

2. Be recertified by a professional engineer registered in the State of Florida that the UST meets all applicable standards of Rule 62-761.500, F.A.C. in effect on July 13, 1998; and

3. Proof of recertification shall be provided to the Department and County prior to the completion of installation. The provisions of Rule 62-761.850(2), F.A.C., do not apply to the requirements of this subparagraph.

(h) Relocation of ASTs. Tanks that have been removed and that are to be reinstalled at a different location shall:

1. For field-erected tanks, comply with API Standard 653; or

2. For shop-fabricated tanks, be reinstalled in accordance with manufacturer's specifications, if applicable, and with the standards in Rule 62-761.500, F.A.C., that were in effect on July 13, 1998.

(i) Reuse of storage tanks. Unless it is recertified for use by a professional engineer registered in the State of Florida, or is recertified by the manufacturer, and is brought into service in accordance with Rule 62-761.500, F.A.C.:

1. A UST can not be used or reused as an AST for the storage of regulated substances; and

2. An AST can not be used or reused as a UST for the storage of regulated substances.

(2) Underground storage tank systems.

(a) Installation.

1. All components of a storage tank system shall be installed in accordance with the manufacturer's instructions.

2. All storage tank systems shall be installed according to the applicable provisions of NFPA 30 and 30A, PEI/RP100-97, and API RP 1615.

3. A Certified Contractor shall perform the installation of storage tank systems containing pollutants, including tanks, integral piping (excluding drop tubes), overfill protection and spill containment equipment, internal release detection equipment, cathodic protection systems, secondary containment systems, and dispensing systems, if the installation of the storage tank system component disturbs the backfill, or where the integral piping is connected or disconnected during installation.

4. A tightness test shall be performed on the tank and integral piping before any storage tank system is placed into service unless the system's equipment approval specifies otherwise.

(b) Tank construction standards.

1. Fiberglass reinforced plastic tanks shall be constructed in accordance with UL 1316 and ASTM Standard D4021-86, or certified by a nationally recognized laboratory that these standards are met.

2. Cathodically protected steel tanks shall be:

a. Constructed in accordance with UL 58 and UL 1746, or as applicable;

b. Constructed in accordance with STI #STI-P_3® Specification and Manual for External Corrosion Protection of Underground Steel Storage Tanks; or

c. Certified by a Nationally Recognized Laboratory that these standards are met, and constructed and designed by a corrosion professional in accordance with NACE International Standard RP0285-95 for any field-installed cathodic protection system.

3. Steel tanks coated with a fiberglass reinforced plastic composite shall be constructed in accordance with UL-58 and either UL 1746, STI ACT 100® (F894), or certified by a nationally recognized laboratory that one of these standards is met.

4. Storage tanks constructed of any other material, design, or corrosion protection shall be approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

5. Any new tank manufactured with previously used or remanufactured components shall be certified before being installed as meeting the applicable standards by Underwriters Laboratory, by a comparable certified product testing laboratory, or by a professional engineer registered in the State of Florida.

6. Tanks shall be constructed or installed to provide for interstitial monitoring.

(c) Secondary containment. All tanks installed or constructed at a facility after July 13, 1998 shall have secondary containment.

(d) Overfill protection.

1. At a minimum, fillbox covers shall be marked in accordance with API RP 1637, or with an equivalent method approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

2. USTs shall be equipped with a system that either:

a. Automatically shuts off flow to the tank when the tank is no more than 95% full;

b. Restricts flow to the tank when the tank is no more than 90% full;

c. Alerts the transfer operator when the tank is no more than 90% full by triggering a high level alarm;

d. Alerts the transfer operator with a high level alarm set at 400 gallons below tank top, but no less than one minute before overfilling; or

e. Automatically shuts off flow into the tank so that none of the fittings located on top of the tank are exposed to product due to overfilling.

(e) Dispenser liners.

1. Storage tank systems installed or replaced after July 13, 1998 shall be installed with liners meeting the performance standards of Rule 62-761.500(1)(e), F.A.C., beneath the union of the piping and the dispenser.

2. Hydrostatic tests shall be performed for all dispenser liners before placing the system into service. The duration of the tests shall be at least:

a. Twenty-four hours for field-fabricated dispenser liners; or

b. Three hours for factory-made dispenser liners.

3. Dispenser liners shall be installed to allow for interstitial monitoring in accordance with Rule 62-761.640(3)(a), F.A.C.

(f) Piping sumps.

1. Piping sumps installed after July 13, 1998 shall meet the performance standards of Rule 62-761.500(1)(e), F.A.C. The sumps shall be designed, constructed, and installed to minimize water entering the sump.

2. Hydrostatic tests shall be performed for all piping sumps before placing the system into service. The duration of the tests shall be at least:

a. Twenty-four hours for field-fabricated piping sumps; or

b. Three hours for factory-made piping sumps.

3. Piping sumps shall be installed to allow for interstitial monitoring in accordance with Rule 62-761.640(3)(a), F.A.C.

(3) Aboveground storage tank systems.

(a) Installation.

1. All components of a storage tank system shall be installed in accordance with the manufacturer's instructions.

2. Storage tank systems shall be installed according to the applicable provisions of NFPA 30, NFPA 30A and PEI/RP200-96.

(b) Tank construction standards.

1. Shop-fabricated tanks shall be constructed in accordance with one of the following:

a. UL 142;

b. API Standard 620;

c. API Specification 12B;

d. API Specification 12F;

e. API Specification 12P;

f. STI F911-93;

g. STI F921®;

h. ASME B96.1; or

i. UL 2085.

2. Field-erected tanks shall be constructed in accordance with one of the following:

a. ASME B96.1;

b. API Standard 620;

c. API Standard 650;

d. API Specification 12B; or

e. API Specification 12D.

3. Field-erected tanks shall have an inspection and testing frequency established in accordance with API Standard 653 and maintained for the life of the tank.

4. Steel tanks in contact with soil shall have a cathodic protection system meeting the following requirements:

a. The cathodic protection system shall be designed, constructed, and installed in accordance with API RP 651 and NACE International Standard RP-0193-93;

b. A field-installed cathodic protection system shall be designed by a Corrosion Professional;

c. The cathodic protection system shall be designed and installed with at least one test station in accordance with Rule 62-761.500(2)(b)2.b., F.A.C., or a method of monitoring to allow for a determination of current operating status; and

d. The cathodic protection system shall be operated and maintained in accordance with Rule 62-761.700(1)(b), F.A.C.

5. Tanks constructed of any other material, design, or corrosion protection shall be approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

(c) Secondary containment.

1. All tanks installed or constructed at a facility after July 13, 1998 shall have secondary containment beneath the tank and within the dike field area, except for the following:

a. Tanks containing high viscosity regulated substances are exempt from the requirements for secondary containment. However, used or waste oil tanks, regardless of viscosity, shall have secondary containment beneath the tank and within the dike field area.

b. Double-walled shop-fabricated tanks approved in accordance with Rule 62-761.850(2), F.A.C., do not have to be installed in a dike field area.

c. Shop-fabricated tanks containing petroleum contact water pursuant to Chapter 62-740, F.A.C., that are subject to this chapter, elevated above and not in contact with the soil, and that have an impervious surface directly beneath the area of the tank.

d. Field-erected tanks used for the temporary storage of petroleum contact water pursuant to Chapter 62-740, F.A.C., that are subject to this chapter, and that have passed an internal inspection for structural integrity in accordance with API Standard 653.

e. AST Category-C field-erected tanks constructed within a dike field area with AST Category-A field-erected tanks shall have secondary containment beneath the tank, but shall not be required to have secondary containment within the dike field area until December 31, 1999.

2. Release prevention barriers such as double-bottoms, liners, or other undertank secondary containment systems for field-erected tanks shall be designed and constructed in accordance with API Standard 650.

3. Dike field areas with secondary containment shall:

a. Conform to the requirements of NFPA 30, Chapter 2-3;

b. Contain a minimum of 110% of the maximum capacity of the tank or of the largest single-walled tank within the dike field area. Capacity calculations shall include the volume occupied above the area of the "footprint" of the tank bottom or the largest tank within the dike field area;

c. If not roofed or otherwise protected from the accumulation of rainfall, be constructed with a manually controlled pump or siphon, or a gravity drain pipe which has a manually controlled valve to remove accumulated liquids. Gravity drain pipes shall be designed and constructed to prevent a discharge in the event of fire;

d. Have all integral piping and other penetrations that pass through the secondary containment of dike field areas sealed around the outside of the penetration with an impervious compatible material to prevent the discharge of pollutants; and

e. If constructed of steel, be tested in accordance with UL 142.

(d) Overfill protection.

1. No transfer of regulated substances shall be made unless the volume available in the tank is greater than the volume of regulated substances to be transferred. The transfer shall be repeatedly monitored to prevent overfilling.

2. Overfill protection shall be performed in accordance with API RP 2350.

3. At a minimum, fillbox covers shall be marked in accordance with API RP 1637, or an equivalent method approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

4. All tanks shall be equipped with at least one of the following:

a. A gauge or other measuring device that accurately shows the level of pollutant in the tank and that is visible to the person who is monitoring the filling;

b. A high level warning alarm;

c. A high level liquid flow cutoff controller;

d. An impervious dike field area; or

e. Another device approved in accordance with Rule 62-761.850(2), F.A.C.

5. Calibrated stick measurements of the level of pollutants in the tank shall only be used for tanks with a capacity of 15,000 gallons or less that are not loaded with high-volume pressurized nozzles. Such tanks shall not be loaded beyond 95% capacity.

(e) Dispenser liners.

1. Dispensers connected to AST systems that are installed or replaced after July 13, 1998 shall be installed with liners meeting the performance standards of Rule 62-761.500(1)(e), F.A.C., beneath the union of the piping and the dispenser. Dispensers mounted directly upon a tank are exempt from this requirement.

2. Hydrostatic tests shall be performed for all dispenser liners before placing the system into service. The duration of the tests shall be at least:

a. Twenty-four hours for field-fabricated dispenser liners; or

b. Three hours for factory-made dispenser liners.

3. Dispenser liners shall be installed to allow for interstitial monitoring in accordance with Rule 62-761.640(3)(a), F.A.C.

(f) Piping sumps.

1. Piping sumps installed after July 13, 1998 shall meet the performance standards of Rule 62-761.500(1)(e), F.A.C. The sumps shall be designed, constructed, and installed to minimize water entering the sump.

2. Hydrostatic tests shall be performed for all piping sumps before placing the system into service. The duration of the tests shall be at least:

a. Twenty-four hours for field-fabricated piping sumps; or

b. Three hours for factory-made piping sumps.

3. Piping sumps shall be installed to allow for interstitial monitoring in accordance with Rule 62-761.640(3)(a), F.A.C.

(4) Integral piping for aboveground and underground storage tank systems.

(a) Installation.

1. All integral piping shall be installed in accordance with the manufacturer's instructions, if applicable.

2. All integral piping shall be installed according to the applicable provisions of NFPA 30, NFPA 30A, and ASME B31.4.

3. A tightness test shall be performed on underground small diameter piping associated with ASTs before any new underground piping system is placed into service. A pressure test shall be performed for underground bulk product piping before the piping system is placed into service. Tightness tests for underground small diameter piping connected to USTs are subject to Rule 62-761.500(2)(a)4., F.A.C.

4. All piping that is not in contact with the soil, installed after July 13, 1998, shall meet the construction standards in Rule 62-761.500(4)(a)-(d), F.A.C.

(b) Integral piping construction standards.

1. Fiberglass reinforced plastic piping or other non-metallic piping installed at a facility shall be listed with UL 971, UL 567, certified by a Nationally Recognized Laboratory that these standards are met, or approved in accordance with Rule 62-761.500(4)(b)3, F.A.C.

2. Coated steel piping shall be constructed in accordance with ASME B31.4. Integral piping in contact with the soil shall be cathodically protected in accordance with API RP 1632, NACE International RP-0169-96, and STI R892-96.

3. Integral piping constructed of other materials, design, or corrosion protection shall be approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

(c) Small diameter piping.

1. Pressurized small diameter piping systems connected to dispensers shall be installed with shear valves or emergency shutoff valves in accordance with NFPA 30A, Section 4-3.6, if applicable. These valves shall be designed to close automatically if a dispenser is dislodged from the integral piping. The valves shall be rigidly anchored independently of the dispenser. For underground small diameter piping, the valves shall be checked at the time of installation by a certified contractor to confirm that the automatic closing function of the valve operates properly and that the valve is properly anchored.

2. Gravity-fed small diameter integral piping systems must be installed with an isolation valve at the point of connection to the storage tank to prevent the discharge of regulated substances in the case of piping failure. The valve shall meet the standards of NFPA 30A, Section 2-1.7.

3. Swing-joints shall not be installed.

(d) Bulk product piping. Bulk product piping shall be constructed and installed in accordance with NFPA 30, and ASME B31.4.

(e) Secondary containment.

1. Small diameter integral piping that is in contact with the soil or that transports regulated substances over surface waters of the state shall have secondary containment.

2. Bulk product piping that is in contact with the soil shall have secondary containment.

3. Remote fill piping that is in contact with the soil shall have secondary containment.

4. The following integral piping systems are exempt from the requirements for secondary containment:

a. Integral piping that is in contact with the soil, and that is connected to storage tanks containing high viscosity regulated substances; and

b. Vertical fill pipes equipped with a drop tube.

Specific Authority 376.303 FS.
Law Implemented 376.303 FS.
History--New 12-10-90, Amended 5-4-92, Formerly 17-761.500, Amended 9-30-96, 7-13-98.

62-761.510 Performance Standards for Category-A and Category-B Storage Tank Systems.

(1) General. This section provides deadlines for Category-A and Category-B storage tank systems to meet the standards for Category-C storage tank systems in accordance with Rule 62-761.500, F.A.C.

(a) Installation:

1. Installation shall be completed by the deadlines specified in Table UST and Table AST. However, if installation or upgrade activities are initiated before the deadlines, work can continue after the deadlines, provided that all work is completed within 90 days of:

a. Contract execution; or

b. Receipt of construction approval or permits.

2. Installation is considered to have begun if:

a. All federal, state, and local approvals or permits have been obtained or applied for to begin physical construction for installation of the system; or

b. Contractual obligations have been made for installation of the system which cannot be canceled or modified without substantial economic loss, provided that such obligations are pursued diligently in good faith to achieve the requirements of this rule.

(b) By December 31, 1998:

1. All pressurized small diameter piping systems connected to dispensers shall have shear valves or emergency shutoff valves installed in accordance with Rule 62-761.500(4)(c), F.A.C.

2. Cathodic protection test stations shall be installed in accordance with Rule 62-761.500(1)(f)1. and (2)(b)2. F.A.C., for cathodically protected UST or AST systems without test stations.

3. Fillboxes shall be color coded in accordance with Rule 62-761.500(2)(d)1., F.A.C.

4. ASTs that have been reinstalled as USTs, and USTs that have been reinstalled as ASTs, shall meet the requirements of Rule 62-761.500, F.A.C.

(c) After July 13, 1998, a closure assessment shall be performed in accordance with Rule 62-761.800(4), F.A.C., before the installation of dispenser liners, piping sumps, or secondary containment of tanks and integral piping.

(d) Valves meeting the requirements of Section 2-1.7 of NFPA 30A, shall be installed by January 13, 1999 on any storage tank system located at an elevation that produces a gravity head on the dispenser or on small diameter piping.

(e) Small diameter piping transporting regulated substances over surface waters of the state shall have secondary containment by December 31, 2004.

(2) Underground storage tank systems.

(a) UST Category-A single-walled tanks or underground single-walled piping shall be considered to be protected from corrosion if the tank or piping was constructed with corrosion resistant materials, initially installed with cathodic protection, or had cathodic protection or internal lining installed before June 30, 1992.

(b) UST Category-B systems.

1. All tanks containing pollutants, installed or constructed at a facility after June 30, 1992, shall have secondary containment.

2. All tanks containing hazardous substances, installed or constructed at a facility after January 1, 1991, shall have secondary containment.

(c) Small diameter integral piping in contact with the soil that is connected to UST systems shall have secondary containment if installed after December 10, 1990.

(d) By December 31 of the appropriate year shown in Table UST below, all storage tank systems shall meet the performance standards of Rule 62-761.500, F.A.C., or be permanently closed in accordance with Rule 62-761.800(3), F.A.C.

TABLE UST

Year Tank or Integral Piping Installed	1989	1992	1995	1998	2004	2009
+Before 1970	O	B		ACFL	D	E
+1970 - 1975		SBL		ACF	D	E
+I976 - 1980		B	SL	ACF	D	E
+1981 - 09/01/84		B		ACFL	D	E
+09/02/84 – 06/30/92		B		ACFL	D	E
+Other*		B		ACFL	D	E

Key to Table UST

* = All systems with a capacity between 110 gallons and 550 gallons, all marine fueling facilities as defined in Section 376.031, F.S., and those systems of greater than 550 gallon capacity that use less than 1,000 gallons per month or 10,000 gallons per year.

A =

(1) Small diameter piping that was protected from corrosion by June 30, 1992, shall have:

(a) For pressurized piping, line leak detectors with automatic shutoff, or flow restriction in accordance with Rule 62-761.640(3)(d), F.A.C.; or

(b) For suction integral piping:

1. Secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C.;

2. A single check valve installed in accordance with Rule 62-761.610(4)(a)3., F.A.C.;

3. An annual line tightness test in accordance with Rule 62-761.610(4)(a)1., F.A.C.; or

4. External monthly monitoring or release detection in accordance with Rule 62-761.610(4)(a)1.b., F.A.C.

(2) Bulk product piping in contact with soil shall be upgraded with secondary containment unless the piping is:

(a) Constructed of corrosion resistant materials or upgraded with cathodic protection; and

(b) Tested on an annual basis in accordance with API RP 1110, ASME B31.4, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C.

B = Vehicular fuel petroleum storage tank systems shall be upgraded with spill containment.

C = Secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C., shall be required for the following:

(1) Concrete storage tanks;

(2) Hazardous substance storage tank systems; and

(3) For pollutant storage tank systems, the storage tank or small diameter piping not protected from corrosion by June 30, 1992.

D = (1) Secondary containment shall be installed for small diameter piping extending over surface waters.

(2) Secondary containment for remote fill-pipes associated with Category-A and Category-B systems.

E = Pollutant storage tanks and small diameter piping protected from corrosion on or before June 30, 1992, and all manifolded piping, shall be upgraded with secondary containment.

F =

(1) Storage tank systems, excluding vehicular fuel petroleum storage tank systems, shall be upgraded with spill containment, dispenser liners (as applicable), and overfill protection.

(2) Unless contained within secondary containment, swing-joints and flex-connectors that are not protected from corrosion shall be protected from corrosion. Facilities that have pressurized small diameter piping and that have not met the foregoing standard on or before July 13, 1998 shall protect the submersible turbine pump from corrosion or provide corrosion protection for the submersible turbine pump if the pump is not installed within secondary containment. Corrosion protection is not required for the submersible turbine pump riser.

L =

(1) Category-A USTs and their integral piping systems that contain vehicular fuel, and that are not protected from corrosion, shall have secondary containment, or be upgraded with secondary containment in accordance with Rule 62-761.500, F.A.C.

(2) Dispenser liners and overfill protection equipment shall be installed at UST Category-A systems containing vehicular fuel.

O = UST Category-A vehicular fuel storage tank systems subject to Chapter 17-61, F.A.C.,(1984), shall be retrofitted for corrosion protection.

S = Secondary containment for storage tanks and integral piping not protected from corrosion.

(3) Aboveground storage tank systems.

(a) All storage tank systems with tanks having capacities greater than 550 gallons that contain vehicular fuel and that were subject to Chapter 17-61, F.A.C., shall have met the requirements of such chapter by January 1, 1990.

(b) AST Category-B tanks, with the exception of tanks exempt under Rule 62-761.500(3)(c)1., F.A.C., installed or constructed at a facility after March 12, 1991, shall have secondary containment for the tank.

(c) Integral piping that is in contact with the soil and that is connected to AST systems shall have secondary containment if installed after March 12, 1991. For integral piping that is exempt under Rule 62-761.500(4)(e)4., F.A.C., it is not required to install secondary containment.

(d) By January 1 of the appropriate year shown in Table AST below, unless specified otherwise, all AST Category-A and Category-B storage tank systems shall meet the following requirements or be permanently closed in accordance with Rule 62-761.800(3), F.A.C.

TABLE AST

Year Tank or Integral Piping Installed	1993	2000	2005	2010
+Before July 13, 1998	P	TVX	W	U

Key to Table AST

P = With the exception of high viscosity bulk product piping, bulk product piping in contact with soil and not in secondary containment shall be tested in accordance with API RP 1110, ASME B31.4, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C. Such testing shall be performed annually thereafter.

T =

(1) With the exception of siting and material construction standards, Category-A and Category-B systems shall meet the performance standards of Rule 62-761.500, F.A.C. In addition:

(a) Storage tank system construction standards that include cathodic protection remain applicable; and

(b) Storage tanks where the entire bottom of the tank is in contact with concrete do not have to seal the concrete beneath the tank until such time that the tank bottom is replaced. However, concrete secondary containment systems designed in accordance with Rule 62-761.500(1)(e)3., F.A.C., do not have to be sealed.

(2) Category-A bulk product piping in contact with the soil shall be upgraded with secondary containment, unless:

(a) A structural evaluation is performed in accordance with API 570, as specified in "U" (2)(b), of Table AST, and results of the structural evaluation indicate that the bulk product piping has remaining useful life; or

(b) The integral piping conveys high viscosity regulated substances, that are exempt from secondary containment in accordance with Rule 62-761.500(4)(e) 4., F.A.C.; or

(c) The integral piping is protected from corrosion and is tested annually in accordance with ASME B31.4, API 1110, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C. This piping shall have secondary containment by January 1, 2010, in accordance with "U" of Table AST.

(3) Initial internal and external inspections, examinations, and tests for each tank shall be performed in accordance with API Standard 653, and an appropriate reinspection interval for each tank shall be established in accordance with API Standard 653. If any deficiency is discovered during the inspections, the person performing the evaluation of the tank in accordance with API 653 must verify that the tank is ready for service before the storage tank is put back into service. This verification must be documented in the internal inspection records. Future tests for each tank shall be performed in accordance with the inspection interval established in accordance with API 653 (1996). Baseline inspections already conducted according to the API Standard 653 (1991) will be accepted.

(4) As an alternative to installing secondary containment underneath an AST Category-A or Category-B storage tank, the interior bottom of the tank and at least 18 inches up the sides may be internally lined in accordance with API RP 652. Secondary containment must nonetheless be installed in the dike field area and be continuously bonded to the perimeter of the tank foundation.

U =

(1) All internally lined single bottom storage tanks, with the exception of tanks exempt under Rule 62-761.500(3)(c)1., F.A.C., shall be upgraded with secondary containment.

(2) All AST Category-A bulk product piping in contact with the soil , except for piping exempt from secondary containment requirements under Rule 62-761.500(4)(e)4. F.A.C., shall be:

(a) Upgraded with secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C.; or

(b) Instead of being upgraded with secondary containment, be evaluated for structural integrity by:

1. Establishing and maintaining the piping inspection intervals in accordance with API 570, Section 4-2, by January 1, 2000;

2. Determining the remaining life of the system in accordance with API 570, Section 5.0, by January 1, 2000. If the determination indicates that the piping:

a. Must be repaired, then the piping shall be repaired within three months of the determination in accordance with API 570 and Rule 62-761.700, F.A.C.;

b. Is leaking, then the piping must be immediately taken out of operation. If the piping cannot be repaired, it must be closed or upgraded with secondary containment within one year of the determination;

c. Is not leaking, but has corroded to a point where it no longer has structural integrity, then the piping shall be closed, or upgraded with secondary containment by January 1, 2000; or

d. Has remaining useful life, then the piping shall be closed or upgraded with secondary containment when the API 570 inspection and remaining life determination data indicates that closure or replacement is necessary.

3. Providing a certification by a professional engineer registered in the State of Florida that the evaluation meets the above criteria.

V =

(1) Secondary containment for cut and cover or concrete storage tanks.

(2) Spill containment in accordance with Rule 62-761.500(1)(c), F.A.C.

(3) Dispenser liners for shop-fabricated tanks in accordance with Rule 62-761.500(3)(e), F.A.C.

(4) Secondary containment in accordance with Rule 62-761.500(1)(e) and (3)(c), F.A.C., for dike field areas of facilities with shop-fabricated tanks having dike field area secondary containment that is constructed of concrete or installed with synthetic liners not meeting these requirements.

W =

(1) Secondary containment in accordance with Rule 62-761.500(1)(e) and (3)(c), F.A.C., for dike field areas of facilities with field-erected tanks having dike field area secondary containment that is constructed of concrete or installed with synthetic liners not meeting these requirements.

(2) Secondary containment for small diameter piping extending over surface waters.

(3) Secondary containment for small diameter petroleum contact water piping in contact with the soil.

X = Deadline to determine integrity of single wall bulk product piping with an API 570 structural integrity evaluation in accordance with the option for Category-A systems in "U" of Table AST.

Specific Authority 376.303 FS. Law Implemented 376.303-376.3072 FS. History--New 12-10-90, Amended 5-4-92, Formerly 17-761.510, Amended 9-30-96, 07-13-98.

62-761.520 Performance Standards for Other Existing Petroleum and Petroleum Product Storage Tank Systems (Non-Vehicular Fuels). (Repealed)

Specific Authority 376.303, FS.
Law Implemented 376.303, FS.
History -- New 12-10-90, Amended 5-4-92, Formerly 17-761.520, Repealed 9-30-96.

62-761.550 Performance Standards for New Hazardous Substance Storage Tank Systems. (Repealed)

Specific Authority 376.303, FS.

FPL'S EXISTING

UNDERGROUND STORAGE TANK SYSTEMS

RRL-2
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-2

Tank ID	Size (Gallons)	Contents	Description	Location	Year Installed	Removal / Replacement	Year of Removal/ Replacement
Tank 1R1	4000	Unleaded Gas	Single-walled	Turkey Point Unit 3 - Land Utilization	1988	Replace with AST	2004
Tank 2R2	4000	Vehicular Diesel	Single-walled	Turkey Point Unit 4 - Land Utilization)	1988	Replace with AST	2004
Tank # 1	1000	Vehicular Diesel	Single-walled	Area Office Broward	1989	Replace with AST	2005
Tank # 1	6000	Vehicular Diesel	Single-walled	Customer Service East Office	1989	Replace with AST	2006
Tank # 1	6000	Unleaded Gas	Single-walled	Juno Beach Office	1986	Replace with AST	2005
Tank # 7&# 8	10000	Vehicular Diesel	Single-walled	General Office	1992	Replace with AST	2005
1	1000	Vehicular Diesel	Single-walled	Ft. Lauderdale Plant	1990	Remove	2004

St. JOHN'S RIVER WATER MANAGEMENT DISTRICT

CONSUMPTIVE USE PERMIT NO. 10652

CAPE CANAVERAL PLANT

RRL-3
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-9

St. Johns River
Water Management District

Kirby B. Green III, Executive Director. John R. Wehle, Assistant Executive Director

Post Office Box 1429 • Palatka, FL 32178-1429 • (386)329-4500

October 9,2001

Florida Power and Light company
6000 North US Highway 1
Cocoa, FL 32927

SUBJECT: Consumptive Use Permit Number 10652
Cape Canaveral Plant

Dear Sir/Madam:

Enclosed is your permit and the forms necessary for submitting information to comply with conditions of the permit as authorized by the St. Johns River Water Management District on October 09,2001.

Permit issuance does not relieve you from the responsibility of obtaining permits from any federal, state and/or local agencies asserting concurrent jurisdiction over this work.

The enclosed permit is a legal document and should be kept with your other important records. Please read the permit and conditions carefully since the referenced conditions may require submittal of additional information. All information submitted as compliance with permit conditions must be submitted to the nearest District Service Center and should include the above referenced permit number.

Please be advised that the period of time within which a third party may request an administrative hearing on this permit may not have expired by the date of issuance. A potential petitioner has twenty-six (26) days from the date on which the actual notice is deposited in the mail, or twenty-one (21) days from publication of this notice when actual notice is not provided, within which to file a petition for an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes. Receipt of such a petition by the District may result in this permit becoming null and void.

Sincerely,

Gloria Lewis, Director
Permit Data Services Division

Enclosures: Permit, Conditions for Issuance, Compliance Forms, Map, Well Tags

cc: District Permit File

PERMIT NO. 10652 **DATE ISSUED:** October 9, 2001

PROJECT Cape Canaveral Plant

A PERMIT AUTHORIZING:

The District authorizes, as limited by the attached permit conditions, the use of up to 91.3 million gallons per year of groundwater from the Surficial aquifer, 54.75 million gallons per year from the Brevard County Sewer Authority, and 300,395 million gallons per year of surface water from the Indian River Lagoon for electrical power generation.

LOCATION:

Site: Cape Canavaral Plant
Brevard County

Section(s): 19 Township(s): 23S Range(s): 36E

ISSUED TO:

Florida Power and Light company
6000 North US Highway 1
Cocoa, FL 32927

Permittee agrees to hold and save the St. Johns River Water Management District and its successors harmless from any and all damages, claims, or liabilities which may arise from permit issuance. Said application, including all maps and specifications attached thereto, is by reference made a part hereof.

This permit does not convey to permittee any property rights nor any rights of privileges other than those specified herein, nor relieve the permittee from complying with any law, regulation or requirement affecting the rights of other bodies or agencies. All structures and works installed by permittee hereunder shall remain the property of the permittee.

This permit may be revoked, modified or transferred at any time pursuant to the appropriate provisions of Chapter 373, Florida Statutes and 40C-1, Florida Administrative Code.

PERMIT IS CONDITIONED UPON:

See conditions on attached "Exhibit A", dated October 9, 2001

AUTHORIZED BY: St. Johns River Water Management District
Department of Resource Management

By: ______________________
Harold A. Wilkening III
Director

By: ______________________
Kirby B. Green, III
Assistant Secretary

"EXHIBIT A"
CONDITIONS FOR ISSUANCE OF PERMIT NUMBER 10652
FLORIDA POWER AND LIGHT COMPANY
DATED OCTOBER 9,2001

1. District Authorized 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.

2. Nothing in this permit should be construed to limit the authority of the St. Johns River Water Management District to declare a water shortage and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate a plan for implementation during periods of water shortage, pursuant to Section 373.246, Florida Statutes. In the event a water shortage, is declared by the District Governing Board, the permittee must adhere to the water shortage restriction as specified by the District, even though the specified water shortage restrictions may be inconsistent with the terms and conditions of this permit.

3. Prior to the construction, modification, or abandonment of a well, the permittee must obtain a Water Well Construction Permit from the St. Johns River Water Management District, or the appropriate local government pursuant to Chapter 40C-3, Florida Administrative Code. Construction, modification, or abandonment of a well will require modification of the consumptive use permit when such construction, modification or abandonment is other than that specified and described on the consumptive use permit application form.

4. Leaking or inoperative well casings, valves, or controls must be repaired or replaced as required to eliminate the leak or make the system fully operational.

5. Legal uses of water existing at the time of the permit application may not be interfered with by the consumptive use. If unanticipated interference occurs, the District may revoke the permit in whole or in part to curtail or abate the interference unless the permittee mitigates for the interference. In those cases where other permit holders are identified by the District as also contributing to the interference, the permittee may choose to mitigate in a cooperative effort with these other permittees. The permittee must submit a mitigation plan to the District for approval prior to implementing such mitigation.

6. Off-site land uses existing at the time of permit application may not be significantly adversely impacted as a result of the consumptive use. If unanticipated significant adverse impacts occur, the District shall revoke the permit in whole or in part to

curtail or abate the adverse impacts, unless the impacts can be mitigated by the permittee.

7. The District must be notified, in writing, within 30 days of any sale, conveyance, or other transfer of a well or facility from which the permitted consumptive use is made or within 30 days of any transfer of ownership or control of the real property at which the permitted consumptive use is located. All transfers of ownership or transfers of permits are subject to the provisions of section 40C-1.612, Florida Administrative Code.

8. A District-issued identification tag shall be prominently displayed at each withdrawal site by permanently affixing such tag to the pump, headgate, valve or other withdrawal facility as provided by Section 40C-2.401, Florida Administrative Code. Permittee shall notify the District in the event that a replacement tag is needed.

9. Landscape irrigation is prohibited between the hours of 10:00 a.m. and 4:00 p.m., except as follows:

a) Irrigation using a micro-irrigation system is allowed anytime.

(b) The use of reclaimed water for irrigation is allowed anytime, provided appropriate signs are placed on the property to inform the general public and District enforcement personnel of such use. Such signs must be in accordance with local restrictions.

(c) Irrigation of, or in preparation for planting, new landscape is allowed any time of day for one 30 day period provided irrigation is limited to the amount necessary for plant establishment.

(d) Watering in of chemicals, including insecticides, pesticides, fertilizers, fungicides, and herbicides when required by law, the manufacturer, or best management practices is allowed anytime within 24 hours of application.

(e) Irrigation systems may be operated anytime for maintenance and repair purposes not to exceed ten minutes per hour per zone.

10. All submittals made to demonstrate compliance with this permit shall have the CUP number 10652 plainly labeled on the submittal.

11. This permit will expire 20 years from the date of issuance.

12. The maximum annual groundwater withdrawal from the Surficial aquifer for electrical power generation must not exceed 91.3 million gallons in the years 2001 through 2006.

13. The maximum daily groundwater withdrawals must not exceed 0.562 million gallons.

14. If the use of reclaimed water from the Brevard County Sewer Authority is deemed feasible, the maximum annual groundwater withdrawal from the Surficial aquifer for electrical power generation must not exceed 36.55 million gallons in years 2007 through 2021 (based on an available reclaimed volume of 0.15 million gallons per day from the Brevard County Port St. John Wastewater Facility). If a connection to the Brevard County Port St. John Wastewater Facility has not been completed then the maximum annual groundwater withdrawal from the Surficial aquifer for electrical power generation must not exceed 91.3 million gallons until the time that connection to reclaimed is complete

15. Maximum annual withdrawals from Surficial aquifer as an emergency backup for electrical power generation must not exceed 54.75 million gallons in the years 2007 through 2021. All available reclaimed water must be utilized prior to using groundwater. The use of groundwater as an emergency supplemental source must be reported separately along with the EN-50 reports outlined in Other Permit Condition No. 10. Documentation verifying the insufficient reclaimed water availability must also be included.

16. The annual surface withdrawal from the Indian River Lagoon for electrical power generation must not exceed 300,395 million gallons per year in the year 2001 through 2021.

17. By December 31, 2003, the permittee must submit a reuse feasibility report to the District. The report must include an executed contractual agreement with Brevard County Sewer Authority that requires the Brevard County Sewer Authority to provide, and the permittee to take and utilize, a minimum of 0.15 million gallons per day of reclaimed water based on an annual average basis. The report must also evaluate whether reclaimed water quality for 2000, 2001, 2002, and the first half of 2003 will meet the permittee's requirements and include a cost evaluation to design, manufacture and install a water delivery system and a dual source water supply system.

18. The use of reclaimed water from the Brevard County Sewer Authority must be implemented by December 31, 2006, if deemed feasible by District staff.

19. The lowest quality water source, such as reclaimed water and surface/storm

water, must be used as irrigation water and process water when available and deemed feasible pursuant to District rules and applicable state law.

20. The permittee has elected to implement an alternative method for Surficial aquifer wells **2 (4277), 3 (4278), 4 (33152), 5 (4280), 6 (4281), 7 (33153), 8 (4283), 9 (4284), 10 (4285), 11 (4286), 12 (4287),** and **13 (4288)** which utilizes an hour meter in conjunction with the measured flow rate for the well as a basis for calculating the quantity of water withdrawn from the well. The method'must be implemented as documented in the Alternative Method Criteria Checklist. The permittee may not alter the approved alternative method without prior written approval from the District. The method must maintain 90% accuracy and be verifiable. If after a period of one year, the selected alternative does not meet the accuracy criteria, totalizing flow meters or another District-approved alternative must be used. If flow meters are used, the meters must maintain **95%** accuracy, be verifiable and be installed according to manufacturer specifications.

21. Total withdrawal from surficial aquifer wells **2 (4277), 3 (4278), 4 (33152), 5 (4280), 6 (4281), 7 (33153), 8 (4283), 9 (4284), 10 (4285), 11 (4286), 12 (4287),** and **13 (4288),** the proposed reclaimed interconnection point **P-1 (34017),** and from the Indian River Lagoon must be recorded continuously, totaled monthly, and reported to the District every six months for the duration of the permit using District Form No. **EN-50.** The reporting dates each year will be as follows:

Reporting Period	Report Due Date
January - June	July **31**
July - December	January **31**

22. The permittee must maintain the meters. In case of failure or breakdown of any meter, the District must be notified in writing within **5** days of its discovery. The defective meter must be repaired or replaced within **30** days of its discovery.

23. If flow meters are installed in place of the hour meters on wells **2 (4277), 3 (4278), 4 (33152), 5 (4280), 6 (4281), 7 (33153), 8 (4283), 9 (4284), 10 (4285), 11 (4286), 12 (4287),** and **13 (4288)** then the permittee must have the flow meters calibrated once every **3** years within **30** days of the anniversary date of permit issuance, and recalibrated if the difference between the actual flow and the meter reading is greater than **5%.** District Form **No. EN-51** must be submitted to the District within **10** days of the inspection/ calibration.

24. The permittee must have wells 5 **(4280)** and **8 (4283)** rehabilitated and put into production within three years of issuance of this permit.

25. The permittee must follow the proposed well field management plan which includes pumping the wells in the following groups: Group I - wells 6 (4281), 11 (4286), 13 (4288) ;Group II - wells 3 (4278), 9 (4284), and 12 (4287) ;Group III - wells 2 (4277), 4 (33152), 7 (33153), and 10 (4285) . The pumping schedule must rotate well groups every 5th day. If the District determines that unacceptable saline water intrusion is occurring as a result of the withdrawals authorized by this permit, the District shall revoke the permit in whole or in part to curtail or abate the saline water intrusion.

26. Water samples for chloride must be collected every two months from Surficial aquifer wells 2 (4277), 3 (4278), 4 (33152), 5 (4280), 6 (4281), 7 (33153), 8 (4283), 9 (4284), 10 (4285), 11 (4286), 12 (4287), and 13 (4288) by the permittee, in accordance with a District approved QNQC program for chloride. The results of the analysis must be submitted to the District starting July 31, . 2002 and then every six months for the duration of the permit along with the mid-year water use submittals following the sampling event. If an evaluation of two years of chloride data indicates that unacceptable saline water intrusion is not occuring, then the chloride sampling frequency may be decreased to semi-annually. If the District determines that unacceptable saline water intrusion is occurring as a result of the withdrawals authorized by this permit, the District shall revoke the permit in whole or in part to curtail or abate the saline water intrusion.

27. Water quality samples must be collected from Surficial aquifer wells 2 (4277), 6 (4281), 8 (4283), 10 (4285), and 12 (4287) by the permittee, in accordance with a District approved QNQC program once a year beginning on May 15, 2002. The samples shall be analyzed for the following parameters: pH, Ca, Cl, Mg, Na, K, S04, C03, HCO3, total dissolved solids, total alkalinity, chloride, and total hardness.
The results will be submitted to the District with the mid-year water use submittals following the sampling event. All major ion analyses must be performed on filtered samples, and must be checked for a cation-anion balance of less than 10%. If a 10% error margin is exceeded in either sample, an additional sample must be collected within 24 hours and reanalyzed. If the District determines that unacceptable saline water intrusion is occurring as a result of the withdrawals authorized by this permit, the District shall revoke the permit in whole or in part to curtail or abate the saline water intrusion.

28. The permittee shall submit, to the District, a compliance report pursuant to subsection 373.236(3), F.S., 5, 10 and 15 years after permit issuance. Specifically, the permittee shall submit the report by October 15 of the years 2006, 2011, and 2016. The report shall contain sufficient information to demonstrate that the permittee's use of water will continue, for the remaining

duration of the permit, to meet the conditions for permit issuance set forth in the District rules that existed at the time the permit was issued by the District.'At a minimum, the compliance report must:

a.) meet the submittal requirements of section **4.2 of** the Applicant's Handbook: Consumptive Uses **of** Water, February **8,** 1999;

b.) include documentation verifying that the source is capable of supplying the needs authorized by this permit without causing harm to water resources;

c.) include documentation verifying that use of water is efficient and that the permittee **is** implementing all feasible water conservation measures;

d.) document that significant saltwater intrusion is not occurring; and

e.) include information documenting that the projected allocation is needed.

St. JOHN'S RIVER WATER MANAGEMENT DISTRICT

CONSUMPTIVE USE PERMIT NO. 9202

SANFORD PLANT

RRL-4
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ____________
PAGES 1-24

Henry Dean, Executive Director
John R. Wehle, Assistant Executive Director

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

POST OFFICE BOX 1429 PALATKA, FLORIDA 32178-1429
TELEPHONE 904-329-4500 SUNCOM 904-860-4500
TDD 9043294450 TDD SUNCOM 6604450
FAX (Executive) 329-4125 (Legal) 329-4465 (Permitting) 329-4315 (Administration/Finance) 329-4508

SERVICE CENTERS

616 E South Street Orlando 407-897-4300 Florida 32801 — 7775 Baymeadows way Jacksonville, Suite 102 Florida 32256 — PERMITTING Melbourne, East Drive Florida 32904 — OPERATIONS Melbourne, N Wickham Road Florida 32935
TDD 407-897-5960 — 904-730-6270 — 407-984-4940 — 407-752-3100
TDD 904-448-7900 — TDD 407-722-5368 — TDD 407-752-3102

June 13, 2000

FLORIDA POWER AND LIGHT COMPANY
950 South Highway 17-92
De Bary, FL 32713

SUBJECT: Consumptive Use Permit Number 9202
FLORIDA POWER AND LIGHT COMPANY

Dear Sir/Madam:

Enclosed is your permit and the forms necessary for submitting information to comply with conditions of the permit as authorized by the St. Johns River Water Management District on June 13, 2000.

Permit issuance does not relieve you from the responsibility of obtaining permits from any federal, state and/or local agencies asserting concurrent jurisdiction over this work.

The enclosed permit is a legal document and should be kept with your other important records. Please read the permit and conditions carefully since the referenced conditions may require submittal of additional information. All information submitted as compliance with permit conditions must be submitted to the nearest District Service Center and should include the above referenced permit number.

Please be advised that the period of time within which a third party may request an administrative hearing on this permit may not have expired by the date of issuance. A potential petitioner has twenty-six (26) days from the date on which the actual notice is deposited in the mail, or twenty-one (21) days from publication of this notice when actual notice is not provided, within which to file a petition for an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes. Receipt of such a petition by the District may result in this permit becoming null and void.

Sincerely,

Gloria Jean Lewis

Gloria Lewis, Director
Permit Data Services Division

Enclosures: Permit, Conditions for Issuance, Compliance Forms, **Map,Well** Tags

cc: District Permit File

PERMIT NO. 9202 **DATE ISSUED:** June 13, 2000
PROJECT NAME: FLORIDA POWER AND LIGHT COMPANY

A PERMIT AUTHORIZING:

The District authorizes, as limited by the attached permit conditions, the use of up to 65778.8 million gallons per year of surface water from the St Johns River and up to 182.5 million gallons per year of ground water from the Floridan aquifer system for commercial industrial use.

LOCATION:

Site: FLORIDA POWER AND LIGHT COMPANY
Volusia County

Section(s):	22, 31, 32	Township(s):	18S	Range(s):	30E
	4, 5, 6, 8, 9, 16		19S		30E

ISSUED TO:

FLORIDA POWER AND LIGHT COMPANY
950 South Highway 17-92
De Bary, FL 32713

Permittee agrees to hold and save the St. Johns River Water Management District and its successors harmless from any and all damages, claims, or liabilities which may arise from permit issuance. Said application, including all maps and specifications attached thereto, is by reference made a part hereof.

This permit does not convey to permittee any property rights nor any rights of privileges other than those specified herein, nor relieve the permittee from complying with any law, regulation or requirement affecting the rights of other bodies or agencies. All structures and works installed by permittee hereunder shall remain the property of the permittee.

This permit may be revoked, modified or transferred at any time pursuant to the appropriate provisions of Chapter 373, Florida Statutes and 40C-1, Florida Administrative Code.

PERMIT IS CONDITIONED UPON:

See conditions on attached "Exhibit A", dated June 13, 2000

AUTHORIZED BY: St. Johns River Water Management District
Department of Resource Management

Hal Wilkening
Director

By: Henry Dean
Henry Dean
Assitant Secretary

"EXHIBIT A"
CONDITIONS FOR ISSUANCE OF PERMIT NUMBER 9202
FLORIDA POWER AND LIGHT COMPANY
DATED JUNE 13, 2000

1. District Authorized 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.

2. Nothing in this permit should be construed to limit the authority of the St. Johns River Water Management District to declare a water shortage and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate a plan for implementation during periods of water shortage, pursuant to Section 373.246, Florida Statutes. In the event a water shortage, is declared by the District Governing Board, the permittee must adhere to the water shortage restriction as specified by the District, even though the specified water shortage restrictions may be inconsistent with the terms and conditions of this permit.

3. Prior to the construction, modification, or abandonment of a well, the permittee must obtain a Water Well Construction Permit from the St. Johns River Water Management District, or the appropriate local government pursuant to Chapter 40C-3, Florida Administrative Code. Construction, modification, or abandonment of a well will require modification of the consumptive use permit when such construction, modification or abandonment is other than that specified and described on the consumptive use. permit application form.

4. Leaking or inoperative well casings, valves, or controls must be repaired or replaced as required to eliminate the leak or make the system fully operational.

5. Legal uses of water existing at the time of the-permit application may not be interfered with by the consumptive use. If unanticipated interference occurs, the District may revoke the permit in whole or in part to curtail or abate the interference unless the permittee mitigates for the interference. In those cases where other permit holders are identified by the District as also contributing to the interference, the permittee may choose to mitigate in a cooperative effort with these other permittees. The permittee must submit a mitigation plan to the District for approval prior to implementing such mitigation.

6. Off-site land uses existing at the time of permit application may not be significantly adversely impacted as a result of the consumptive use. If unanticipated significant adverse impacts occur, the District shall revoke the permit in whole or in part to curtail or abate the adverse impacts, unless the impacts can be mitigated by the

permittee.

7. The District must be notified, in writing, within 30 days of any sale, conveyance, or other transfer of a well or facility from which the permitted consumptive use is **made** or within 30 days of any transfer of ownership or control of the real property at'which the permitted consumptive use is located. All transfers of ownership or transfers of permits are subject to the provisions of section 40C-1.612, Florida Administrative Code.

8. A District-issued identification tag shall be prominently displayed at each withdrawal site by permanently affixing such tag to the pump, headgate, valve or other withdrawal facility as provided by Section 40C-2.401, Florida Administrative Code. Permittee shall notify the District in the event that a replacement tag is needed.

9. Permittee must implement the conservation plan approved by the District in accordance with the schedule contained therein. A report detailing the progress of plan implementation must be submitted to the District on or before the midpoint of the permit duration.

10. All submittals made to demonstrate compliance with this permit must have the CUP number 9202 plainly labeled on the submittal.

11. This permit will expire twenty (20) years from the date of issuance.

12. Maximum annual ground water withdrawals for commercial industrial use must not exceed:

    182.5 million gallons in 2000 through 2002,
    103.7 million gallons in 2003 through 2020.

13. The maximum annual surface water surface water withdrawals for commercial industrial use must not exceed:

    65,700 million gallons in 2000 through 2002,
    65778.8 million gallons in 2003 through 2020.

14. The maximum daily surface water withdrawals for cooling and circulating must not exceed 270 million gallons per day.

15. The lowest quality water source, such as surface -water or reclaimed water, must be used as commercial industrial water in place of ground water when available and deemed feasible pursuant to District rules and applicable state law.

16. Within 6 months of permit issuance, wells 3 (No. 17680) and 4 (No. 17681) and pumps CW3A (No. 2956), CW 3B (No. 2957), OCW 3A (No. 22455) OCW 3B (No. 22454) and proposed pumps LF 3A (No. 22457) and LF 3B (No. 22456) must be equipped with totalizing flow meters or an alternative method for measuring flow must be implemented. The method must be implemented as documented in the permit application received by the District on August 9, 1999.

The permittee has elected to implement an alternative method for pumps CW3A (No. 2956), CW 3B (No. 2957), OCW 3A (No. 22455) OCW 3B (No. 22454) and proposed pumps LF 3A (No. 22457) and LF 3B (No. 22456) where the pump on/off times are electronically recorded. The flow is determined using the running times of the pumps and the appropriate pump log curves and pump rate as a basis for calculating the quantity of water withdrawn from the St Johns River. The permittee may not alter the approved alternative method without prior written approval from the District. The method must maintain 90% accuracy and be verifiable. If after a period of one year, the selected alternative method does not meet the accuracy criteria, a totalizing flow meter or another District-approved alternative must be used. If flow meters are used, the meters must maintain 95% accuracy, be verifiable and be installed according to manufacturer specifications. Documentation of proper installation of the flow meter may be accomplished by a site visit by District staff, or by submitting a copy of the manufacturer's specifications and a photograph within 30 days of meter installation.

17. The permittee must maintain all meters or other District approved flow measuring devices. In case of failure or breakdown of any meter or other device, the District must be notified in writing within 5 days of its discovery. A defective meter or other device must be repaired or replaced within 30 days of its discovery.

18. If utilized, the permittee must have all flow meters checked for accuracy at least once every 3 years within 30 days of the anniversary date of permit issuance, and recalibrated if the difference between the actual flow and the meter reading is greater than 5%. District Form No. EN-51 must be submitted to the District within 10 days of the inspection/calibration.

19. Total withdrawal, from well numbers 3 (No. 17680) and 4 (No. 17681), and pumps CW3A (No. 2956), CW 3B (No. 2957), OCW 3A (No. 22455) OCW 3B (No. 22454) and proposed pumps LF 3A (No. 22457) and LF 3B (No. 22456) as listed on the application, must be recorded continuously, totaled monthly, and reported to the District every six months for the duration of the permit using District Form No. EN-50. The reporting dates each year will be as follows:

Reporting Period	Report Due Date

January - June	July 31
July - December	January 31

20. Water samples must be collected in May every odd numbered year starting in 2001 from well number 3 (No. 17680) and submitted to a Department of Health and Rehabilitative Services or Florida Department of Environmental Protection approved laboratory for analysis. All water samples shall be analyzed for the following:

Calcium	Total Alkalinity
Sodium	Magnesium
Chlorides	Total Hardness
pH	Carbonate

All major ion analyses shall be conducted on filtered samples, and shall be checked for a cation-anion balance of less than 10%. If this 10% error margin is exceeded in any sample, an additional sample shall be collected immediately and reanalyzed. Results of these tests shall be submitted to the District by July 31 along with EN-50 reports. If the District determines that unacceptable saline water intrusion is occurring as a result of the withdrawals authorized by this permit, the District shall revoke the permit in whole or in part to curtail or abate the saline water intrusion.

21. The permittee shall submit, to the District, a compliance report pursuant to subsection 373.236(3), F.S., 5, 10, 15, and 20 years after permit issuance. Specifically, the permittee shall submit the reports by June 14, 2005, June 14, 2010, June 14, 2015, and June 14, 2020. The reports shall contain sufficient information to demonstrate that the permittee's use of water will continue, for the remaining duration of the permit, to meet the conditions for permit issuance set forth in the District rules that existed at the time the permit was issued by the District. At a minimum, the compliance report must:

(a) meet the submittal requirements of section 4.2 of the Applicant's Handbook: Consumptive Uses of Water, February 8, 1999;

(b) include documentation verifying that the source is capable of supplying the needs authorized by this permit without causing harm to water resources:

(c) include documentation verifying that the permittee is implementing all feasible water conservation measures;

(d) document that the lowest acceptable quality water source, including reclaimed water or surface water (which includes storm water), must be utilized for each consumptive use;

(e) ensure that all monitoring requirements are met;

(f) document that significant saltwater intrusion is not occurring; and include information documenting that the projected allocation is needed.

36204

St. Johns River Water Management Distric
P. 0. Box 142
Palatka, Florida 32178-142

WATER USE RECORD FORM EN • 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME 3 PUMP NAME

COMPLETE THE FORM BY PRINTING EACH "NUMBER" WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. **MARK ALL THAT APPLY**

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): ____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

		GALLONS	OR METER READING:
JAN	**00**		
FEB	**00**		
MAR	**00**		
APR	**00**		
MAY	**00**		
JUN	**00**		

Step 3. CONTACT NAME ____

PHONE NUMBER ____

17680

362041

St. Johns River Water Management Distric
P. 0. Box 142!
Palatka, Florida 32178-1 42!

WATER USE RECORC FORM EN • 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME 4 PUMP NAME

COMPLETE THE FORM BY PRINTING EACH "NUMBER" WITHOUTTOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

- O NO USE THIS PERIOD
- O WELL CAPPED
- O WELL ABANDONED (40C-3, FAC)
- O PROPERTY SOLD
- O COMMENTS: (PLEASE PRINT): ______________________

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING5
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME ______________________

PHONE NUMBER ______________________

17681

362041

St. Johns River Water Management Distri(
P. 0. Box 1422
Palatka, Florida 32178-142

WATER USE RECORC FORM EN - 50

CUP# 9 2 0 2 PERMIT ISSUE DATE 13-jun-2000

)ISTRICT ID OWNERS ID

'ERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

VELL NAME CW3A PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER' WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. **MARK ALL THAT APPLY**

0 NO USE THIS PERIOD
0 WELL CAPPED
0 WELL ABANDONED (40C-3, FAC)
O PROPERTY SOLD
O COMMENTS: (PLEASE PRINT): ____________________

Step 2. **REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).**

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

itep 3. CONTACT NAME ____________________

PHONE NUMBER ____________________

2956

36204

St. Johns River Water Management Distri(
P. 0. Box 1422
Palatka, Florida 32178-I 42'

WATER USE RECORC FORM EN • 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

ᴾERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME CW3B PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER" WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. **MARK ALL THAT APPLY**

0 NO USE THIS PERIOD

0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC)

O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): ____________________

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME ____________________

PHONE NUMBER ____________________

2957

362041

St. Johns River Water Management Distric
P. 0. Box 1422
Palatka, Florida 32178-142

WATER USE RECORC FORM EN •50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME LF3A PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER" WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): ______________________________

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME ______________________________

PHONE NUMBER ______________________________

22457

36204

St. Johns River Water Management Distric
P. O. Box 142$
Palatka, Florida 32178-142

WATER USE RECORC FORM EN · 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME LF3B PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER' WITHOUT TOUCHING THE SIDES OF THE BOX

0 1 2 3 4 5 6 7 8 9

Step 1. **MARK ALL THAT APPLY**

0 NO USE THIS PERIOD
0 WELL CAPPED
0 WELL ABANDONED (40C-3, FAC)
O PROPERTY SOLD
O COMMENTS: (PLEASE PRINT): ____________________

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME ____________________

PHONE NUMBER ____________________

22456

362041

St. Johns River Water Management Distric
P. O. Box 142$
Palatka, Florida 32178-142

WATER USE RECORC FORM EN-50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME OCW3A PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER' WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): ______________________________

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME ______________________________

PHONE NUMBER ______________________________

22455

36204

St. Johns River Water Management Distri(
P. 0. Box 1422
Palatka, Florida 32178-I 42'

WATER USE RECORC FORM EN - 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME OCW3B PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER" WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): ______________________

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

		GALLONS	OR METER READING:
JAN	00		
FEB	00		
MAR	00		
APR	00		
MAY	00		
JUN	00		

Step 3. CONTACT NAME ______________________

PHONE NUMBER ______________________

224'54

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **3**

ump Capacity: **200 GPM**

erial Number on Meter: ______________________________

eter Model: ______________________________

ischarge Pipe Diameter: ______________________________

ate of Last Meter Calibration: _______/_______/_______

ate of This Calibration: _______/_______/_______

ame of Person Performing Calibration: ______________________________

____

ethod or Equipment Used for Calibration: ______________________________

____

itial Meter Reading at Start of Calibration: ______________________________

nal Meter Reading at End of Calibration: ______________________________

eadings on Equipment Used for Calibration:

Start: ____________________ End: ____________________

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: ____________%

ame of Person Completing Form (Please Print): ______________________________

ompany Name: ______________________________

ddress: ______________________________

ity/State/Zip: ______________________________

aytime Telephone: (______) _______ - ____________

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: 9202

ermittee Name: FLORIDA POWER AND LIGHT COMPANY

ate of Permit Issuance: June 13, 2000 Station Name: 4

ump Capacity: 200 GPM

erial Number on Meter: ______________________________

eter Model: ______________________________

ischarge Pipe Diameter: ______________________________

ate of Last Meter Calibration: ________/________/________

ate of This Calibration: ________/________/________

ame of Person Performing Calibration: ______________________________

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ethod or Equipment Used for Calibration: ______________________________

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itial Meter Reading at Start of Calibration: ______________________________

nal Meter Reading at End of Calibration: ______________________________

eadings on Equipment Used for Calibration:

Start: ______________________ End: ______________________

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: ______________%

ame of Person Completing Form (Please Print): ______________________________

ompany Name: ______________________________

ddress: ______________________________

ity/State/Zip: ______________________________

aytime Telephone: (______) ________ - ______________

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **CW3A**

ump Capacity: **65000 GPM**

erial Number on Meter: ______________________________

leter Model: ______________________________

ischarge Pipe Diameter: ______________________________

ate of Last Meter Calibration: ________/________/________

ate of This Calibration: ________/________/________

lame of Person Performing Calibration: ______________________________

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lethod or Equipment Used for Calibration: ______________________________

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nitial Meter Reading at Start of Calibration: ______________________________

inal Meter Reading at End of Calibration: ______________________________

leadings on Equipment Used for Calibration:

Start: ______________________ End: ______________________

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: ______________%

lame of Person Completing Form (Please Print): ______________________________

ompany Name: ______________________________

ddress: ______________________________

ity/State/Zip: ______________________________

aytime Telephone: (______) ________ - ______________

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **CW3B**

ump Capacity: **65000 GPM**

erial Number on Meter: ______________________________

ıeter Model: ______________________________

ischarge Pipe Diameter: ______________________________

ate of Last Meter Calibration: ______/______/______

ate of This Calibration: ______/______/______

ame of Person Performing Calibration: ______________________________

____

ıethod or Equipment Used for Calibration: ______________________________

____

ıitial Meter Reading at Start of Calibration: ______________________________

ınal Meter Reading at End of Calibration: ______________________________

eadings on Equipment Used for Calibration:

Start: ____________________ End: ____________________

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: ____________%

ame of Person Completing Form (Please Print): ______________________________

ompany Name: ______________________________

ddress: ______________________________

ity/State/Zip: ______________________________

aytime Telephone: (______) ________ - ____________

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

ɔnsumptive Use Permit Number: 9202

ɜrmittee Name: FLORIDA POWER AND LIGHT COMPANY

ate of Permit Issuance: June 13, 2000 Station Name: LF3A

ımp Capacity: 10000 GPM

ɜrial Number on Meter: ______________________

eter Model: ______________________

scharge Pipe Diameter: ______________________

ate of Last Meter Calibration: ______/______/______

ate of This Calibration: ______/______/______

ame of Person Performing Calibration: ______________________

____

ethod or Equipment Used for Calibration: ______________________

____

itial Meter Reading at Start of Calibration: ______________________

nal Meter Reading at End of Calibration: ______________________

eadings on Equipment Used for Calibration:

Start: ______________ End: ______________

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: __________%

ame of Person Completing Form (Please Print): ______________________

ɔmpany Name: ______________________

ldress: ______________________

ty/State/Zip: ______________________

ıytime Telephone: (______) ______ - __________

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: 9202

ermittee Name: FLORIDA POWER AND LIGHT COMPANY

ate of Permit Issuance: June 13, 2000 Station Name: LF3B

ump Capacity: 10000 GPM

erial Number on Meter: ______________________________

eter Model: ______________________________

ischarge Pipe Diameter: ______________________________

ate of Last Meter Calibration: ________/________/________

ate of This Calibration: ________/________/________

ame of Person Performing Calibration: ______________________________

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ethod or Equipment Used for Calibration: ______________________________

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itial Meter Reading at Start of Calibration: ______________________________

nal Meter Reading at End of Calibration: ______________________________

eadings on Equipment Used for Calibration:

Start: ______________________ End: ______________________

(Attach Formulas Used to Make Calculations)

rcent of Error Between Meter Reading and Calibration Equipment: ____________%

ame of Person Completing Form (Please Print): ______________________________

ompany Name: ______________________________

dress: ______________________________

ity/State/Zip: ______________________________

aytime Telephone: (______) ________ - ______________

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **OCW3A**

ump Capacity: **4514 GPM**

erial Number on Meter: ______________________________

eter Model: ______________________________

ischarge Pipe Diameter: ______________________________

ate of Last Meter Calibration: ________/________/________

ate of This Calibration: ________/________/________

ame of Person Performing Calibration: ______________________________

____

ethod or Equipment Used for Calibration: ______________________________

____

itial Meter Reading at Start of Calibration: ______________________________

inal Meter Reading at End of Calibration: ______________________________

eadings on Equipment Used for Calibration:

Start: ______________________ End: ______________________

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: ____________%

ame of Person Completing Form (Please Print): ______________________________

ompany Name: ______________________________

dress: ______________________________

ity/State/Zip: ______________________________

aytime Telephone: (______) ________ - ______________

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: 9202

ermittee Name: FLORIDA POWER AND LIGHT COMPANY

ate of Permit Issuance: June 13, 2000 Station Name: OCW3B

ump Capacity: 4514 GPM

erial Number on Meter: ______________________________

eter Model: ______________________________

ischarge Pipe Diameter: ______________________________

ate of Last Meter Calibration: ______/______/______

ate of This Calibration: ______/______/______

ame of Person Performing Calibration: ______________________________

____

ethod or Equipment Used for Calibration: ______________________________

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itial Meter Reading at Start of Calibration: ______________________________

nal Meter Reading at End of Calibration: ______________________________

eadings on Equipment Used for Calibration:

Start: ____________________ End: ____________________

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: __________%

ame of Person Completing Form (Please Print): ______________________________

ompany Name: ______________________________

ddress: ______________________________

ity/State/Zip: ______________________________

aytime Telephone: (______) ________ - ____________

Please Retain a Copy for Your Records

DRAFT

TITLE V AIR OPERATION PERMIT RENEWAL

PROPOSED PERMIT NO. 0110036-006-AV

RRL-5
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-40

Title V Air Operation Permit Renewal
PROPOSED Permit No. **0110036-006-AV**

Table of Contents

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of four fossil fuel steam generators and twelve simple cycle combustion turbines.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V permit renewal application received on April 24, 2003, this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 225 MW, 2400 mmBtu/hr for natural gas and 2300 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 2 fuel oil, propane and on-specification used oil from FPL operations, with emissions exhausted through a 344 ft. stack.
002	Fossil Fuel Steam Generator, Unit 2, rated at 225 MW, 2400 mmBtu/hr for natural gas and 2300 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 2 fuel oil, propane and on-specification used oil from FPL operations, with emissions exhausted through a 344 ft. stack.
003	Fossil Fuel Steam Generator, Unit 3, rated at 402 MW, 4180 mmBtu/hr for natural gas and 4000 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 2 fuel oil, propane and on-specification used oil from FPL operations, with emissions exhausted through a 344 ft. stack.
004	Fossil Fuel Steam Generator, Unit 4, rated at 402 MW, 4180 mmBtu/hr for natural gas and 4000 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, diesel fuel, propane and on-specification used oil from FPL operations, with emissions exhausted through a 344 ft. stack.
005	12 Simple Cycle Gas Turbines, GT1 through GT12, with a total capacity rated at 504 MW, 8424 mmBtu/hr, capable of burning any combination of, number 2 fuel oil and natural gas, with emissions exhausted through twelve 44 ft. stacks.

Unregulated Emissions Units and/or Activities	
017	Above ground fuel oil storage tanks
018	Miscellaneous internal combustion engines and portable equipment

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

<u>These documents are provided to the permittee for information purposes only:</u>
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

<u>These documents are on file with the permitting authority:</u>
Title V Permit Renewal Application received on April 24, 2003.
DRAFT Title V Air Operation Permit Renewal clerked on June 5, 2003.
Letter from the applicant received on June 20, 2003.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. Appendix TV-4, Title V Conditions, is a part of this permit.
{Permitting note: Appendix TV-4, Title V Conditions, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. **Not Federally Enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4, F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

and,

b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6), and 62-4.040(1)(b), F.A.C.]

7. **Not Federally Enforceable.** General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. The owner or operator shall:

a. Tightly cover or close all VOC or OS containers when they are not in use.
b. Tightly cover all open tanks which contain VOC or OS when they are not in use.
c. Maintain all pipes, valves, fittings, etc., which handle VOC or OS in good operating condition.
d. Immediately confine and clean up VOC or OS spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

[Rule 62-296.320(1)(a), F.A.C.]

8. **Not Federally Enforceable.** No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility shall include:

a. The facility shall construct temporary sandblasting enclosures when necessary, in order to perform sandblasting on fixed plant equipment.
b. Maintenance of paved areas shall be performed as needed.
c. Regular mowing of grass and care of vegetation shall be performed.
d. Access to plant property by unnecessary vehicles shall be limited.
e. Bagged chemical products shall be stored in weather-tight buildings until they are used.
f. Spills of powdered chemical products shall be cleaned up as soon as practicable.
g. Vehicles shall be restricted to slow speeds on the plant site.

[Rule 62-296.320(4)(c)2., F.A.C.; and proposed by applicant in the Title V permit renewal application received on April 24, 2003.]

9. When appropriate, any recording, monitoring or reporting requirements that are time-specific shall be in accordance with the effective date of this permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of Appendix TV-4, Title V Conditions).}

11. Submittals. All reports, tests, notifications or other submittals required by this permit shall be submitted to the Broward County Department of Planning and Environmental Protection, Air Quality Division, and copies of those submittals shall be sent to the Department of Environmental Protection, Southeast District Office, Air Section. Addresses and telephone numbers are:

Broward County Department of Planning and Environmental Protection
Air Quality Division
218 SW 1st Avenue
Ft. Lauderdale, FL 33301
Phone: 954/519-1220

Department of Environmental Protection
Southeast District Office, Air Section
P.O. Box 15425
West Palm Beach, FL 33416
Phone: 561/681-6600

Any reports, data, notifications, certifications and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air & EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, GA 30303
Phone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

12. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit(s).

E.U. ID No.	**Brief Description**
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Fossil fuel fired steam generators Unit 1 and Unit 2 are each 225 MW (electric) steam generators. The emissions units are fired on a variable combination of No. 6 fuel oil, No. 2 fuel oil, natural gas, propane, and on-specification used oil from FPL operations. When firing fuel oil, the maximum heat input for each boiler is 2300 mmBtu per hour, and when firing natural gas or propane, the maximum heat input for each boiler is 2400 mmBtu per hour.

Each emissions unit consists of a boiler that drives a turbine generator. Emissions are controlled with low NOx burners, and multiple cyclones for particulate matter (for the period 1/01/04 through 10/31/05 for Unit 001, and period 1/01/04 through 4/01/05 for Unit 002). Electrostatic precipitators shall replace the multiple cyclones beyond these dates. Each unit is equipped with a 344-foot stack. *Following the construction and installation of the ESPs at the facility, these emissions units will be subject to Compliance Assurance Monitoring (CAM) for those control devices. See Specific Condition* ***A.15.1.***

{Permitting note(s): These emissions units are regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 1 began commercial operation in 1960 and fossil fuel fired steam generator Unit 2 began commercial operation in 1961. These emissions units may inject additives such as magnesium hydroxide and related compounds into each boiler.}

The following specific conditions apply to the emissions units listed above:

<u>Essential Potential to Emit (PTE) Parameters</u>

A.1. <u>Permitted Capacity</u>. The maximum operation heat input rates are as follows:

Unit No.	mmBtu/hr Heat Input*	Fuel Type
1	2400 2300	Natural Gas, Propane No. 2 or 6 Fuel Oil
2	2400 2300	Natural Gas, Propane No. 2 or 6 Fuel Oil

*When a blend of fuel oil and natural gas or propane is burned, the heat input is prorated based upon the percent heat input of each fuel.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

A.2. Emissions Unit Operating Rate Limitation After Testing. Emissions units may be limited to the operating rate or conditions tested. See Specific Conditions **D.14.** and **A.15.** of this permit.
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation. Fuels. The only fuels allowed to be burned are any combination of No. 6 fuel oil, No. 2 fuel oil, natural gas, propane, and on-specification used oil from FPL operations.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **A.4.1.** through **A.9.** are based on the specified averaging time of the applicable test method.}

A.4.1. Visible Emissions – Steady State Operation (effective 01/01/04 through 5/31/06 for Unit 001, and 01/01/04 through 10/31/05 for Unit 002). Visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions standard shall conduct a compliance test for visible emissions annually using EPA Reference Method 9.
[Rule 62-296.405(1)(a), F.A.C.; and Order dated January 2, 1986 (Unit 1), and OGC Case No. 83-0578, Order dated April 24, 1984 (Unit 2).]

A.4.2. Visible Emissions – Steady State Operation (effective 6/01/06 for Unit 001, and 11/01/05 for Unit 002). Visible emissions shall not exceed 20 percent opacity. Emissions units governed by this visible emissions standard shall conduct a compliance test for visible emissions annually using EPA Reference Method 9.
[0110036-005-AC, Specific Condition A.16.]

A.5.1. Visible Emissions - Soot Blowing and Load Change (effective 01/01/04 through 5/31/06 for Unit 001, and 01/01/04 through 10/31/05 for Unit 002). Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

Note: these units have operational continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

A.5.2. Visible Emissions -- Soot Blowing and Load Change (effective 6/01/06 for Unit 001, and 11/01/05 for Unit 002). Visible emissions shall not exceed 40 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 40 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

Note: these units have operational continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.; and 0110036-005-AC, Specific Condition A.17.]

A.6.1. Particulate Matter – Steady State Operation (effective 01/01/04 through 5/31/06 for Unit 001, and 01/01/04 through 10/31/05 for Unit 002). Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

A.6.2. Particulate Matter – Steady State Operation (effective 6/01/06 for Unit 001, and 11/01/05 for Unit 002). Particulate matter emissions shall not exceed 0.03 pound per million Btu heat input, as measured by applicable compliance methods.
[0110036-005-AC, Specific Condition A.18.]

A.7.1. Particulate Matter - Soot Blowing and Load Change (effective 01/01/04 through 5/31/06 for Unit 001, and 01/01/04 through 10/31/05 for Unit 002). Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

A.7.2. Particulate Matter -- Soot Blowing and Load Change (effective 6/01/06 for Unit 001, and 11/01/05 for Unit 002). Particulate matter emissions shall not exceed an average of 0.1 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[0110036-005-AC, Specific Condition A.19.]

A.8. Sulfur Dioxide. Sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods. Compliance shall be based on the total heat input from all liquid and gaseous fuels burned. The sulfur dioxide emission limitation shall apply at all times including startup, shutdown, and load change. See Specific Condition **A.11.**
[Rules 62-213.440 and 62-296.405(1)(c)1.j., F.A.C.]

A.9. Nitrogen Oxides. Nitrogen oxides emissions shall not exceed 0.20 pounds per million Btu while firing natural gas, and 0.36 pounds per million Btu while firing oil. Compliance shall be demonstrated based on a 30-day rolling average as measured by a continuous emissions monitoring system (CEMS). The CEMS must meet the performance specifications contained in 40 CFR 60, Appendix B, or 40 CFR 75.
[Rules 62-296.570(4)(a)4. and (4)(b)1., F.A.C.]

Monitoring of Operations

A.10. Annual Tests Required, PM and VE. Except as provided in specific conditions **D.6** and **D.7** of this permit, emission testing for particulate emissions and visible emissions shall be performed annually, no later than September 30th of each year, except for units that are not operating because of scheduled maintenance outages and emergency repairs, which will be tested within thirty days of returning to service.
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

A.11. Sulfur Dioxide. The owner or operator of the emission units shall demonstrate compliance with the sulfur dioxide limit of specific condition **A.8** of this permit by the following:

a. Through the use of a continuous emission monitoring system (CEMS) installed, calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800, F.A.C. A Relative Accuracy Test Audit of the SO_2 CEMS shall be conducted no less than annually. Compliance shall be demonstrated based on a 3-hour rolling average.

b. In the event the CEMS becomes temporarily inoperable or interrupted, the fuels and the maximum fuel oil to natural gas firing ratio that shall be used is limited to that which was last used to demonstrate compliance prior to the loss of the CEMS, or the emissions units shall fuel switch and be fired with a fuel oil containing a maximum sulfur content of 2.5%, by weight, or less.

c. When burning 100% fuel oil, the emissions units shall be fired with a fuel oil containing a maximum sulfur content of 2.5%, by weight, or less.

[Rules 62-213.440, 62-204.800 and 62-296.405(1)(c)3., F.A.C.]

<u>**Test Methods and Procedures**</u>

A.12. <u>Testing While Injecting Additives</u>. The owner or operator shall conduct emission tests while injecting additives consistent with normal operating practices.
[Rule 62-213.440, F.A.C., applicant agreement with EPA on March 3, 1998]

A.13. <u>Particulate Matter</u>. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17. Particulate testing shall be conducted in accordance with the requirements of specific conditions **D.14** and **A.15** of this permit.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

A.14. <u>Sulfur Dioxide</u>. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, **the permittee shall demonstrate compliance using CEMS for sulfur dioxide. See specific condition A.11 of this permit.**
[Rules 62-213.440 and 62-296.405(1)(c)3. and (1)(e)3., F.A.C.]

A.15. <u>Operating Conditions During Testing - PM and VE</u>. Compliance testing during sootblowing and steady-state operation for particulate matter and visible emissions shall be conducted at least once annually, if liquid fuel is fired for more than 400 hours. A visible emissions test shall be conducted during one run of each particulate matter test. Testing shall be conducted as follows:

a. <u>When Burning 100% Fuel Oil</u>. Particulate matter and visible emissions tests during sootblowing and steady-state operation shall be performed on such emissions unit while firing solely fuel oil of less than or equal to 2.5% sulfur by weight (stoichiometrically representative of sulfur dioxide emissions of the SO_2 emission limit of 2.75 lb/mmBtu), except that such test shall not be required to be performed during any year that testing is performed in accordance with specific condition **A.15.b.**

b. <u>When Burning Fuel Oil While Co-firing With Natural Gas</u>. Particulate matter and visible emissions tests during sootblowing and steady-state operation shall be performed on such

emissions unit while co-firing oil with the appropriate proportion of natural gas required to maintain SO_2 emissions below the emission limit of 2.75 lb/mmBtu heat input.
Test Required if Target SO_2 Emission Rate Increased. Following successful completion of such PM and VE testing, further PM and VE testing shall not be required during the next 12 months unless fuel oil is fired that contains greater than 0.20% sulfur above the percentage sulfur concentration fired during the most recent co-firing test. If fuel oil is co-fired containing greater than 0.20% sulfur above the percentage sulfur concentration fired during the most recent co-firing test, additional PM and VE tests shall be performed as described above as soon as practicable, but in no event more than 60 days after firing such higher sulfur fuel oil.
[Rules 62-4.070(3), 62-213.440, 62-296.405(1)(c)3. and 62-297.310(7)(a)9., F.A.C., Request of applicant; Administrative Correction 0110036-002-AV.]

Compliance Assurance Monitoring (CAM) Requirements

A.15.1. Following the construction and installation of the ESPs at the facility, these emissions units will be subject to Compliance Assurance Monitoring (CAM) for those control devices. Therefore, six months following the completion of construction the permittee shall request a revision to this permit to include the requirements for the proposed CAM plan.
[40 CFR 64; and Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

Recordkeeping and Reporting Requirements

A.16. Fuel Records. The owner or operator shall create and maintain for each emission unit hourly records of the amount of each fuel fired, the ratio of fuel oil to natural gas if co-fired, and the heating value and sulfur content of each fuel fired. These records must be of sufficient detail to identify the testing requirements of Specific Condition **A.15.**, and, when applicable, demonstrate compliance with the requirements of Specific Condition **A.11.**, paragraphs b and c, of this permit. Fuel oil heating value and sulfur content shall be determined by taking a daily sample of the fuel fired, combining those samples into a monthly composite, and analyzing a representative sample of the composite. Analysis for sulfur content shall be performed using one of ASTM D2622-94, ASTM D4294-90(95), ASTM D1552-95, ASTM D1266-91, both ASTM D4057-88 and ASTM D129-95, or the latest edition(s). Comparison of the as-fired fuel oil sulfur content shall be made and recorded monthly upon receipt of each monthly composite analysis.
[Rules 62-4.070(3), 62-213.410, 62-213.440 and 62-296.405(1)(c)3., F.A.C.]

A.17. COMS for Periodic Monitoring. The owner or operator is required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C., and applicant agreement with EPA on March 3, 1998]

Other Conditions

A.18. These emissions units are also subject to Specific Conditions **D.1.** through **D.20.**, contained in **Subsection D., Common Conditions.**

Subsection B. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4

Fossil fuel fired steam generators Unit 3 and Unit 4 are each 402 MW (electric) steam generators. The emissions units are fired on a variable combination of No. 6 fuel oil, No. 2 fuel oil, natural gas, propane, and on-specification used oil from FPL operations. When firing fuel oil, the maximum heat input for each boiler is 4000 mmBtu per hour, and when firing natural gas or propane, the maximum heat input for each boiler is 4180 mmBtu per hour. Each emissions unit consists of a boiler which drives a turbine generator. Emissions are controlled with low NOx burners and multiple cyclones for particulate matter (for the period 1/01/04 through 10/31/07 for Unit 003, and period 1/01/04 through 5/31/07 for Unit 004). Electrostatic precipitators shall replace the multiple cyclones beyond these dates. Each unit is equipped with a 344-foot stack. *Following the construction and installation of the ESPs at the facility, these emissions units will be subject to Compliance Assurance Monitoring (CAM) for those control devices. See Specific Condition **B.15.1.***

{Permitting note(s): These emissions units are regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 3 began commercial operation in 1965, and fossil fuel fired steam generator Unit 4 began commercial operation in 1964. These emissions units may inject additives such as magnesium hydroxide and related compounds into each boiler.}

The following specific conditions apply to the emissions units listed above:

<u>Essential Potential to Emit (PTE) Parameters</u>

B.1. <u>Permitted Capacity</u>. The maximum operation heat input rates are as follows:

Unit No.	mmBtu/hr Heat Input*	Fuel Type
3	4180 4000	Natural Gas, Propane No. 2 or 6 Fuel Oil
4	4180 4000	Natural Gas, Propane No. 2 or 6 Fuel Oil

*When a blend of fuel oil and natural gas or propane is burned, the heat input is prorated based upon the percent heat input of each fuel.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

B.2. <u>Emissions Unit Operating Rate Limitation After Testing</u>. Emissions units may be limited to the operating rate or conditions tested. See Specific Conditions **D.14.** and **B.15.** of this permit.
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation. Fuels. The only fuels allowed to be burned are any combination of No. 6 fuel oil, No. 2 fuel oil, natural gas, propane, and on-specification used oil from FPL operations.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **B.4.1.** through **B.9.** are based on the specified averaging time of the applicable test method.}

B.4.1. Visible Emissions – Steady State Operation (effective 01/01/04 through 10/31/07 for Unit 003, and 01/01/04 through 05/31/07 for Unit 004). Visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions standard shall conduct a compliance test for visible emissions annually using EPA Reference Method 9.
[Rule 62-296.405(1)(a), F.A.C.; and OGC Case No. 83-0577 & 83-0576, Order dated April 24, 1984.]

B.4.2. Visible Emissions – Steady State Operation (effective 11/01/07 for Unit 003, and 06/01/07 for Unit 004). Visible emissions shall not exceed 20 percent opacity. Emissions units governed by this visible emissions standard shall conduct a compliance test for visible emissions annually using EPA Reference Method 9.
[0110036-005-AC, Specific Condition A.16.]

B.5.1. Visible Emissions – Soot Blowing and Load Change (effective 01/01/04 through 10/31/07 for Unit 003, and 01/01/04 through 05/31/07 for Unit 004). Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

Note: these units have operational continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

B.5.2. Visible Emissions – Soot Blowing and Load Change (effective 11/01/07 for Unit 003, and 06/01/07 for Unit 004). Visible emissions shall not exceed 40 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 40 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

Note: these units have operational continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.; and 0110036-005-AC, Specific Condition A.17.]

B.6.1. Particulate Matter – Steady State Operation (effective 01/01/04 through 10/31/07 for Unit 003, and 01/01/04 through 05/31/07 for Unit 004). Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

B.6.2. Particulate Matter – Steady State Operation (effective 11/01/07 for Unit 003, and 06/01/07 for Unit 004). Particulate matter emissions shall not exceed 0.03 pound per million Btu heat input, as measured by applicable compliance methods.
[0110036-005-AC, Specific Condition A.18.]

B.7.1. Particulate Matter – Soot Blowing and Load Change (effective 01/01/04 through 10/31/07 for Unit 003, and 01/01/04 through 05/31/07 for Unit 004). Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

B.7.2. Particulate Matter – Soot Blowing and Load Change (effective 11/01/07 for Unit 003, and 06/01/07 for Unit 004). Particulate matter emissions shall not exceed an average of 0.1 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[0110036-005-AC, Specific Condition A.19.]

B.8. Sulfur Dioxide. Sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods. Compliance shall be based on the total heat input from all liquid and gaseous fuels burned. The sulfur dioxide emission limitation shall apply at all times including startup, shutdown, and load change. See Specific Condition **B.11.**
[Rules 62-213.440 and 62-296.405(1)(c)1.j., F.A.C.]

B.9. Nitrogen Oxides. Nitrogen oxides emissions shall not exceed 0.40 pounds per million Btu while firing natural gas, and 0.53 pounds per million Btu while firing oil. Compliance shall be demonstrated based on a 30-day rolling average as measured by a CEMS. The CEMS must meet the performance specifications contained in 40 CFR 60, Appendix B, or 40 CFR 75.
[Rules 62-296.570(4)(a)4. and (4)(b)2., F.A.C.]

Monitoring of Operations

B.10. Annual Tests Required, PM and VE. Except as provided in Specific Conditions **D.6.** and **D.7.** of this permit, emission testing for particulate emissions and visible emissions shall be performed annually, no later than September 30th of each year, except for units that are not operating because of scheduled maintenance outages and emergency repairs, which will be tested within thirty days of returning to service.
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

B.11. Sulfur Dioxide. The owner or operator of the emission units shall demonstrate compliance with the sulfur dioxide limit of Specific Condition **B.8.** of this permit by the following:

a. Through the use of a continuous emission monitoring system (CEMS) installed, calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800, F.A.C. A Relative Accuracy Test Audit of the SO_2 CEMS shall be conducted no less than annually. Compliance shall be demonstrated based on a 3-hour rolling average.

b. In the event the CEMS becomes temporarily inoperable or interrupted, the fuels and the maximum fuel oil to natural gas firing ratio that shall be used is limited to that which was last used to demonstrate compliance prior to the loss of the CEMS, or the emissions units shall fuel switch and be fired with a fuel oil containing a maximum sulfur content of 2.5%, by weight, or less.

c. When burning 100% fuel oil, the emissions units shall be fired with a fuel oil containing a maximum sulfur content of 2.5%, by weight, or less.

[Rules 62-213.440, 62-204.800 and 62-296.405(1)(c)3., F.A.C.]

Test Methods and Procedures

B.12. Testing While Injecting Additives. The owner or operator shall conduct emission tests while injecting additives consistent with normal operating practices.
[Rule 62-213.440, F.A.C., applicant agreement with EPA on March 3, 1998]

B.13. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17. Particulate testing shall be conducted in accordance with the requirements of specific conditions **D.14** and **B.15** of this permit.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

B.14. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, **the permittee shall demonstrate compliance using CEMS for sulfur dioxide. See specific condition B.11 of this permit**.
[Rules 62-213.440 and 62-296.405(1)(c)3. and (1)(e)3., F.A.C.]

B.15. Operating Conditions During Testing - PM and VE. Compliance testing during sootblowing and steady-state operation for particulate matter and visible emissions shall be conducted at least once annually, if liquid fuel is fired for more than 400 hours. A visible emissions test shall be conducted during one run of each particulate matter test. Testing shall be conducted as follows:

a. When Burning 100% Fuel Oil. Particulate matter and visible emissions tests during sootblowing and steady-state operation shall be performed on such emissions unit while firing solely fuel oil of less than or equal to 2.5% sulfur by weight (stoichiometrically representative of sulfur dioxide emissions of the SO_2 emission limit of 2.75 lb/mmBtu), except that such test shall not be required to be performed during any year that testing is performed in accordance with specific condition **B.15.b.**

b. When Burning Fuel Oil While Co-firing With Natural Gas. Particulate matter and visible emissions tests during sootblowing and steady-state operation shall be performed on such emissions unit while co-firing oil with the appropriate proportion of natural gas required to maintain SO_2 emissions below the emission limit of 2.75 lb/mmBtu heat input.
Test Required if Target SO_2 Emission Rate Increased. Following successful completion of such PM and VE testing, further PM and VE testing shall not be required during the next 12 months unless fuel oil is fired that contains greater than 0.20% sulfur above the percentage sulfur concentration fired during the most recent co-firing test. If fuel oil is co-fired containing greater than 0.20% sulfur above the percentage sulfur concentration fired during the most recent co-firing test, additional PM and VE tests shall be performed as described above as soon as practicable, but in no event more than 60 days after firing such higher sulfur fuel oil.
[Rules 62-4.070(3), 62-213.440, 62-296.405(1)(c)3. and 62-297.310(7)(a)9., F.A.C., Request of applicant; Administrative Correction 0110036-002-AV.]

Compliance Assurance Monitoring (CAM) Requirements

B.15.1. Following the construction and installation of the ESPs at the facility, these emissions units will be subject to Compliance Assurance Monitoring (CAM) for those control devices. Therefore, six months following the completion of construction the permittee shall request a revision to this permit to include the requirements for the proposed CAM plan.
[40 CFR 64; and Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

Recordkeeping and Reporting Requirements

B.16. Fuel Records. The owner or operator shall create and maintain for each emission unit hourly records of the amount of each fuel fired, the ratio of fuel oil to natural gas if co-fired, and the heating value and sulfur content of each fuel fired. These records must be of sufficient detail to identify the testing requirements of specific condition **B.15**, and, when applicable, demonstrate compliance with the requirements of condition **B.11**, paragraphs b and c, of this permit. Fuel oil heating value and sulfur content shall be determined by taking a daily sample of the fuel fired, combining those samples into a monthly composite, and analyzing a representative sample of the composite. Analysis for sulfur content shall be performed using one of ASTM D2622-94, ASTM D4294-90(95), ASTM D1552-95, ASTM D1266-91, both ASTM D4057-88 and ASTM D129-95, or the latest edition(s). Comparison of the as-fired fuel oil sulfur content shall be made and recorded monthly upon receipt of each monthly composite analysis.
[Rules 62-4.070(3), 62-213.410, 62-213.440 and 62-296.405(1)(c)3., F.A.C.]

B.17. COMS for Periodic Monitoring. The owner or operator is required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C., and applicant agreement with EPA on March 3, 1998]

Other Conditions

B.18. These emissions units are also subject to Specific Conditions **D.1.** through **D.20.**, contained in **Subsection D., Common Conditions.**

Subsection C. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
005	12 Simple Cycle Gas Turbines, GT1 through GT12

Emissions unit 005 consists of 12 simple cycle gas turbines (GT1 through GT12) manufactured by Pratt & Whitney, with a total capacity rated at 504 MW, 8424 mmBtu/hr. The emissions units are fired on any combination of No. 2 fuel oil and natural gas. Each turbine unit consists of two turbine engines which drive a turbine generator. Emissions are uncontrolled. Each unit is equipped with a 44-foot stack. The turbines are regulated collectively as one emission unit.

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are *not subject* to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. All turbines began commercial operation in 1971.}

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	mmBtu/hr Heat Input*	Fuel Type
GT1 through GT12	8424	Natural Gas
	8424	No. 2 Fuel Oil

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

C.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **D.14.** of this permit.
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation. Fuels. The only fuels allowed to be burned are any combination of No. 2 fuel oil and natural gas.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **C.4.** and **C.5.** are based on the specified averaging time of the applicable test method.}

C.4. Visible Emissions. Visible emissions from each turbine shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.]

C.5. Nitrogen Oxides. Nitrogen oxides emissions shall not exceed 0.50 pounds per million Btu while firing natural gas, and 0.90 pounds per million Btu while firing oil.
[Rules 62-296.570(4)(b)5., F.A.C.]

Monitoring of Operations

C.6. Visible Emissions Testing Required. The owner or operator shall conduct testing for visible emissions, using EPA Method 9, while the combustion turbine is operating at 90-100 percent of its capacity, according to the following schedule.

The owner or operator shall conduct testing for visible emissions while firing fuel oil for each simple-cycle turbine unit upon that turbine's exceeding 400 hours of operation on fuel oil, and every 150 hours of operation on fuel oil thereafter, in any given federal fiscal year (October 1 through September 30). Such tests shall be performed within 15 days of exceeding such operating hours, to allow for prior notification of the tests.
[Rule 62-213.440, F.A.C.; applicant agreement with EPA on March 3, 1998; and AO 06-230618.]

C.7. Nitrogen Oxides. Provided operation is no more than 320 hours/year/turbine on oil, NOx emissions for the combustion turbines shall be tested every five (5) years by EPA Method 20 tests as described in 40 CFR 60, Appendix A (July 1, 1996) on any representative unit in the bank of the combustion turbines. Tests shall be conducted both while burning 100% natural gas and 100% light distillate oil.
[Rule 62-296.570, F.A.C.; and requested by the applicant in a letter dated September 19, 2000.]

Test Methods and Procedures

C.8. Nitrogen Oxides. The test method for nitrogen oxides emissions shall be EPA Method 20, or EPA Method 7E, incorporated by reference in Chapter 62-297, F.A.C. If the owner or operator obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall automatically become a condition of this permit.
[Rules 62-213.440, 62-296.570(4)(a)3., 62-297.401, F.A.C.; and applicant request.]

Recordkeeping and Reporting Requirements

C.9. Records of Fuel Consumption and Operating Time Required. The owner or operator shall make and maintain records of the hours of operation of each turbine and the total fuel oil consumption of all twelve turbines in sufficient detail to ensure compliance with Specific Condition **C.6.** of this permit.
[Rule 62-4.070(3), F.A.C.]

Other Conditions

C.10. These emissions units are also subject to Specific Conditions **D.1.** through **D.19.**, contained in **Subsection D., Common Conditions.** Specific Condition **D.20.** is not applicable to these emission units.

Subsection D. Common Conditions.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1.
002	Fossil Fuel Steam Generator, Unit 2.
003	Fossil Fuel Steam Generator, Unit 3.
004	Fossil Fuel Steam Generator, Unit 4.
005	12 Simple Cycle Gas Turbines, GT1 through GT12.

The following conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

D.1. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

Excess Emissions

D.2. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.3. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

D.4. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

D.5. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

D.6. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant

emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C., SIP Approved]

D.7. When PM Tests Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

D.8. When VE Tests Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-4.070(3), F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.9. Visible Emissions - Turbines. The test method for visible emissions for emissions unit 005 (bank of twelve combustion turbines) shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800 and 62-297.401, F.A.C.]

D.10. Visible Emissions - Boilers, Units 1, 2, 3 and 4. The test method for visible emissions for emissions units 001 (Unit 1), 002 (Unit 2), 003 (Unit 3) and 004 (Unit 4) shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See Specific Condition **D.11**.
[Rules 62-296.405(1)(e)1. and 62-297.401, F.A.C.]

D.11. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:
   a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
   b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rule 62-297.401, F.A.C.]

D.12. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

D.13. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

D.14. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

D.15. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

D.16. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

Recordkeeping and Reporting Requirements

D.17. Malfunctions - Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Broward County Department of Planning and Environmental Protection, Air Quality Division, in accordance with Rule 62-4.130, F.A.C. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Broward County Department of Planning and Environmental Protection, Air Quality Division.
[Rule 62-210.700(6), F.A.C.]

D.18. Excess Emissions - Report. Submit to the Broward County Department of Planning and Environmental Protection, Air Quality Division, a written report of emissions in excess of emission limiting standards as set forth in this permit, for each calendar quarter. The nature and

cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

D.19. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Broward County Department of Planning and Environmental Protection, Air Quality Division, on the results of each such test.
(b) The required test report shall be filed with the Broward County Department of Planning and Environmental Protection, Air Quality Division, as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Broward County Department of Planning and Environmental Protection, Air Quality Division, to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

D.20. Used Oil. Burning of on-specification used oil is allowed in emissions units 001, 002, 003 and 004 in accordance with all other conditions of this permit and the following additional conditions:

a. On-specification Used Oil Allowed as Fuel: This permit allows the burning of used oil fuel meeting EPA "on-specification" used oil specifications, with a PCB concentration of less than 50 ppm, originating from FPL operations. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility.

   On-specification used oil shall meet the following specifications: [40 CFR 279, Subpart B.]

   Arsenic shall not exceed 5.0 ppm;
   Cadmium shall not exceed 2.0 ppm;
   Chromium shall not exceed 10.0 ppm;
   Lead shall not exceed 100.0 ppm;
   Total halogens shall not exceed 1000 ppm;
   Flash point shall not be less than 100 degrees F.

b. Quantity Limited: The maximum total quantity of used oil that may be burned in all four emissions units is 1.5 million gallons in any consecutive 12-month period.

c. Used Oil Containing PCBs Not Allowed: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. PCB Concentration of 2 to less than 50 ppm: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Required: The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

   Arsenic, cadmium, chromium, lead, total halogens, flash point, and PCBs.

   Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition.

f. Record Keeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department: [40 CFR 279.61 and 761.20(e)]

(1) The gallons of on-specification used oil received and burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)
(2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)
(3) Results of the analyses required above.

g. Reporting Required: The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted]

Section IV. This Section is the Acid Rain Part.

Operated by: Florida Power and Light Company
ORIS code: **0617**

Subsection A. This Subsection addresses Acid Rain, Phase II.

The emissions unit(s) listed below are regulated under Phase II of the federal Acid Rain Program.

E.U. ID No.	EPA ID No.	Brief Description
001	PPE1	Fossil Fuel Steam Generator, Unit 1
002	PPE2	Fossil Fuel Steam Generator, Unit 2
003	PPE3	Fossil Fuel Steam Generator, Unit 3
004	PPE4	Fossil Fuel Steam Generator, Unit 4

1. The Phase II part application renewal submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application renewal listed below:

a. DEP Form No. 62-210.900(1)(a), effective 04/16/01, and signed by the Designated Representative on 04/07/03.

[Chapter 62-213, F.A.C.; and Rule 62-214.320, F.A.C.]

2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2004	2005	2006	2007	2008
001	**PPE1**	**SO2 allowances, under Table 2 of 40 CFR Part 73**	2339*	2339*	2339*	2339*	2339*
002	**PPE2**	**SO2 allowances, under Table 2 of 40 CFR Part 73**	2413*	2413*	2413*	2413*	2413*
003	**PPE3**	**SO2 allowances, under Table 2 of 40 CFR Part 73**	5880*	5880*	5880*	5880*	5880*

E.U. ID No.	EPA ID	Year	2004	2005	2006	2007	2008
004	PPE4	SO2 allowances, under Table 2 of 40 CFR Part 73	5962*	5962*	5962*	5962*	5962*

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 of 40 CFR 73.

3. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, Fast-Track Revisions of Acid Rain Parts.
[Rule 62-213.413, F.A.C.]

4. Comments, notes, and justifications. The Phase II Part Application Renewal form was received on April 24, 2003.

5. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1., 2. & 3., F.A.C.]

6. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year.
{See condition No. 51., Appendix TV-4, Title V Conditions.}
[Rule 62-214.420(11), F.A.C.]

7. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

Appendix I-1, List of Insignificant Emissions Units and/or Activities

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities
1. Spent boiler chemical cleaning liquid evaporation.
2. Laboratory equipment used exclusively for chemical or physical analysis.
3. Brazing, soldering, or welding equipment.
4. Surface coating facilities provided that 6.0 gallons of coatings per day or less are applied.
5. Hydrazine feed line vent.
6. Lube oil system.
7. Oil/water separators and related equipment.
8. Misc. mobile vehicle operation.
9. Paint & lube oil building.
10. Chemical storage building.
11. Hazardous waste storage area.
12. Natural gas metering station.
13. Internal combustion engine.
14. Fire and safety equipment.

Appendix H-1, Permit History/ID Number Changes

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1, 2]	Revised Date(s)
001	Fossil Fuel Steam Generator #1	AO 06-223345	04/21/93	02/28/98		
002	Fossil Fuel Steam Generator #2	AO 06-223350	04/21/93	02/15/98		
003	Fossil Fuel Steam Generator #3	AO 06-223351	04/21/93	02/15/98		
004	Fossil Fuel Steam Generator #4	AO 06-223352	04/21/93	02/15/98		
005	Gas Turbine Generator #1 - 12	AO 06-230618	06/16/93	06/04/98		
001-005	As noted above.	0110036-001-AV 0110036-002-AV (Administrative Correction) 0110036-003-AV	06/24/98 02/26/01	12/31/03 12/31/03 12/31/03		
001-004	As noted above.	0110036-005-AC	07/14/03	04/01/07		

ID Number Changes (for tracking purposes):

From: **Facility ID No.:** 50BRO060036

To: **Facility ID No.:** 0110036

Notes:
1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective.}

Appendix U-1, List of Unregulated Emissions Units and/or Activities

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'insignificant emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activity
017	Above ground fuel oil storage tanks
018	Miscellaneous internal combustion engines and portable equipment

Table 1-1, Summary of Air Pollutant Emission Standards

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

			Allowable Emissions			Equivalent Emissions[1,2]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
VE Steady State	Oil, Natural Gas or Propane	8760	40% opacity, or 20% opacity (see Specific Condition **A.4.2.**)					Rule 62-296.405(1)(a), F.A.C.	**A.4.**
VE Soot Blowing or Load Change	Oil, Natural Gas or Propane	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods), or 40 % opacity (>40% opacity for not more than 4, six-minute periods) (see Specific Condition **A.5.2.**)					Rule 62-210.700(3), F.A.C.	**A.5.**
PM Steady State	Oil, Natural Gas or Propane	8760	0.1 lb/mmBtu, or 0.03 lb/mmBtu (see Specific condition **A.6.2.**)			230, or 69		Rule 62-296.405(1)(b), F.A.C.	**A.6.1.**, or **A.6.2.**
PM Soot Blowing or Load Change	Oil, Natural Gas or Propane	8760	0.3 lb/mmBtu, or 0.1 lb/mmBtu (see Specific condition **A.7.2.**)			690, or 230		Rule 62-210.700(3), F.A.C.	**A.7.1.**, or **A.7.2.**

Table 1-1, Continued

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

			Allowable Emissions			Equivalent Emissions[1,2]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	**lb/hour**	**TPY**	Regulatory Citations	See Permit Condition(s)
SO_2	Oil, Natural Gas	8760	2.75 lb/mmBtu			**6325***	**27704***	Rule 62-296.405(1)(c)1.j., F.A.C.	**A.8.**
NO_x	Oil	8760	0.36 lb/mmBtu			**828**	**3626.6**	Rule 62-296.570(4)(b)1, F.A.C.	**A.9.**
NO_x	Natural Gas	8760	0.20 lb/mmBtu			**480**	**2102.4**	Rule 62-296.570(4)(b)1, F.A.C.	**A.9.**

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Table 1-1, Continued

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4

			Allowable Emissions			Equivalent Emissions[1,2]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
VE Steady State	Oil, Natural Gas or Propane	8760	40% opacity, or 20% opacity (see Specific Condition **B.4.2.**)					Rule 62-296.405(1)(a), F.A.C.	**B.4.**
VE Soot Blowing or Load Change	Oil, Natural Gas or Propane	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods), or 40 % opacity (>40% opacity for not more than 4, six-minute periods) (see Specific Condition **B.5.2.**)					Rule 62-210.700(3), F.A.C.	**B.5.**
PM Steady State	Oil, Natural Gas or Propane	8760	0.1 lb/mmBtu, or 0.03 lb/mmBtu (see Specific Condition **B.6.2.**)			400, or 120		Rule 62-296.405(1)(b), F.A.C.	**B.6.1.**, or **B.6.2.**
PM Soot Blowing or Load Change	Oil, Natural Gas or Propane	8760	0.3 lb/mmBtu, or 0.1 lb/mmBtu (see Specific Condtion **B.7.2.**)			1200, or 400		Rule 62-210.700(3), F.A.C.	**B.7.1.**, or **B.7.2.**

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Table 1-1, Continued

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4

			Allowable Emissions			Equivalent Emissions[1,2]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
SO_2	Oil, Natural Gas	8760	2.75 lb/mmBtu			**11000***	**48180***	Rule 62-296.405(1)(c)1.j., F.A.C.	**B.8.**
NO_x	Oil	8760	0.53 lb/mmBtu			2120	9285.6	Rules 62-296.570(4)(b)2, F.A.C.	**B.9.**
NO_x	Natural Gas	8760	0.40 lb/mmBtu			1672	7323.4	Rule 62-296.570(4)(b)2, F.A.C.	**B.9.**

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Table 1-1, Continued

Emissions Unit	Brief Description
005	12 Simple Cycle Gas Turbines, GT1 through GT12.

			Allowable Emissions			Equivalent Emissions[1,3]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
VE Steady State	Oil, Natural Gas or Propane	8760	20% opacity					Rule 62-296.320(4)(b)1., F.A.C.	**C.4.**
NO_x	Oil	8760	0.90 lb/mmBtu			7581.6	33207	Rule 62-296.570(4)(b)2, F.A.C.	**C.5.**
NO_x	Natural Gas	8760	0.50 lb/mmBtu			4212	18449	Rule 62-296.570(4)(b)5, F.A.C.	**C.5.**

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Notes:

[1] The "Equivalent Emissions" listed are for informational purposes only.
[2] The "Equivalent Emissions" are for each emission unit, unless otherwise noted.
[3] The "Equivalent Emissions" are for all twelve turbines combined.
*Lb/hr and TPY values are for SO_2 emissions using fuel oil.

Table 2-1, Summary of Compliance Requirements

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	Oil, Natural Gas or Propane	DEP Method 9	Annual	September 30	1 hour	No	**A.10. & A.15.**
PM	Oil, Natural Gas or Propane	EPA Test Methods 5, 5B, or 17	Annual	September 30	3 hours	No	**A.10., A.13. & A.15.**
SO_2	Oil, Natural Gas or Propane	Continuous Emissions Monitor	Continuous			Yes	**A.11. & A.14.**
NOx	Oil, Natural Gas or Propane	Continuous Emissions Monitor	Continuous			Yes	**A.9.**

Table 2-1, Continued

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	Oil, Natural Gas or Propane	DEP Method 9	Annual	September 30	1 hour	No	**B.10. & B.15.**
PM	Oil, Natural Gas or Propane	EPA Test Methods 5, 5B, or 17	Annual	September 30	3 hours	No	**B.10., B.13. & B.15.**
SO_2	Oil, Natural Gas or Propane	Continuous Emissions Monitor	Continuous			Yes	**B.11. & B.14.**
NOx	Oil, Natural Gas or Propane	Continuous Emissions Monitor	Continuous			Yes	**B.9.**

Table 2-1, Continued

Emissions Unit	Brief Description
005	12 Simple Cycle Gas Turbines, GT1 through GT12.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	Oil, Natural Gas	EPA Method 9	Annual, each turbine exceeding fuel limit.	October 31	30 min.	No	**C.6.**
NOx	Oil, Natural Gas	EPA Method 20 or EPA Method 7E	Every five years, one turbine only, provided operation is no more than 320 hours/year/ turbine on oil.	September 30	3 hours	No	**C.7., C.8.**

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Notes:

[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system

ADVANTAGES/DISADVANTAGES

PARTICULATE REMOVAL TECHNOLOGIES

RRL-6
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-2

Advantages and Disadvantages of Particulate Removal Technologies				
Characteristic	**Mechanical Collectors**	*** ESPs**	**Fabric Filters**	**Combustion Controls**
Capability of producing < 5% opacity	No	Yes	Yes	No
Suitable for No. 6 oil-fired boilers	Yes	Yes	No	Yes
Flue gas pressure drop, inwg	4 to 6	1 to 2	-------	NA
Energy demand (other than ID fan)	None	High	-------	High
Capital cost	Lowest	High	-------	Moderate
Operating/Maintenance cost - relative	Low	High	-------	Moderate

* Recommended Technology

Items of note in this table are the mechanical collector's inability to achieve the desired plume opacity and the fabric filter's unsuitability for flue gas generated by No. 6 fuel oil due to the stickiness of the ash and resultant potential for the bags to be "blinded".

ADVANTAGES/DISADVANTAGES

SO_3 REMOVAL TECHNOLOGIES

RRL-7
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-2

Advantages and Disadvantages of SO_3 Removal Technologies				
Characteristic	**Alkaline Reagent Injection**		**Wet ESP**	**** Flue Gas Reheat**
	**** MgO**	**Na_2SO_3 / $NaHSO_3$**		
Capability of producing < 10 ppm SO_3	Yes	Yes	Yes	No
Visible moisture plume produced	No	No	Yes	No – would prevent such plume
Suitable for No. 6 oil-fired boilers	Yes	Yes	Yes	Yes
Flue gas pressure drop, inwg	<1	<1	2 to 4	<1
Energy demand (other than ID fan)	Low	Low	High	Low
Level of development	Demonstrated	Developmental	Demonstrated	Demonstrated
Space requirements – relative	Low	Low	High	Low
Effect on existing stacks	None	None	Corrosion resistant lining required	None
Capital cost - relative	Very Low	Very low	Very high	Low
Operating/Maintenance cost - relative	High	High	High	Low

**Recommended Technology