Security

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 020007-EI
FLORIDA POWER & LIGHT COMPANY

SEPTEMBER 9, 2002

ENVIRONMENTAL COST RECOVERY

PROJECTIONS
JANUARY 2003 THROUGH DECEMBER 2003

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. 020007-EI

SEPTEMBER 9, 2002

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 2003 through December 2003 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, it is. 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, I have. 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 provides a summary of Environmental costs being presented for the period January 2003 through December 2003. Total environmental costs, adjusted for revenue taxes, amount to $19,149,944 (Appendix I, Page 2, Line 5a) and include $11,049,501 of environmental project costs (Appendix I, Page 2, Line 1c) increased by the estimated/ actual underrecovery of $7,799,426 for the January 2002 - December

2002 period as filed on August 9, 2002 (Appendix I, Page 2, Line 4).

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

A. Form 42-2P 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 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 34) 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 35 through 61) 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 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 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 Pipeline Integrity Management Program Project which was filed with the Commission on August 9, 2002, the St. Lucie Turtle Net project which was filed with the Commission on June 18, 2002, and two new environmental projects, the Manatee Reburn NOx Control Technology Project, and the Spill Prevention, Control, and Countermeasures Project, which are presented in the testimony of R. R. LaBauve.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 020007-EI

September 9, 2002

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

A. Yes, I have. It consists of the following documents:

Document RRL-2, Conceptual Application of Reburning in a Utility Boiler.

Document RRL-3, Environmental Protection Agency 40 CFR Part 112.

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, two new environmental projects – the Manatee Reburn NOx Control Technology Project and the Spill Prevention, Control, and Countermeasures (SPCC) Project. Additionally, I will address a change to the Pipeline Integrity Management Program Project. This project was filed with the Commission on August 9, 2002.

MANATEE REBURN NOx CONTROL TECHNOLOGY PROJECT

Q. Please briefly describe the scope of the Manatee Reburn NOx Control Technology Project.

A. The Manatee Reburn NOx Control Technology Project will be the subject of an agreement between FPL and the Florida Department of Environmental Protection (FDEP) to install reburn technology at the Manatee Plant Units 1 and 2 for the exclusive purpose of ensuring compliance with ozone ambient air quality standards in the Tampa Bay Airshed, as provided for by Section 366.8255, Florida Statutes, as amended in 2002. FPL has discussed the project with the FDEP staff and FPL and the FDEP are working to formalize this in a written agreement as contemplated by Section 366.8255(1)(d) 7, Florida Statutes. FPL expects to receive the finalized agreement near the end of September 2002, and will provide the Commission with a copy of the agreement when it is signed.

Q. What is the statutory basis for FPL's request in this docket?

A. A new paragraph 7 was added to the definition of "environmental compliance costs" in Subsection 366.8255(1)(d), Florida Statutes by the 2002 Legislature (Chapter 2002-276, Laws of Florida). Governor Bush signed the legislation into law on May 23, 2002. For purposes of environmental cost recovery under Section 366.8255, such "environmental compliance costs" are now defined to include "costs or expenses prudently incurred by an electric utility pursuant to an agreement entered into on or after the effective date of this act and prior to October 1, 2002, between the electric utility and the Florida Department of Environmental Protection or the United States Environmental Protection Agency for the exclusive purpose of ensuring compliance with ozone ambient air quality standards by an electrical generating facility owned by the electric utility."

Q. Please explain how the Manatee Reburn NOx Control Technology Project relates to ozone ambient air quality standards.

A. The U.S. EPA has promulgated a new ambient air quality standard for ozone that establishes a permissible limit on the level of ozone during any 8-hour period. Manatee County is located in the vicinity of the Tampa Bay Airshed, which has experienced recent episodes of elevated ozone levels higher than the U.S. EPA's new ambient air quality standard for ozone on at least 15 separate days in the past four years. Despite expected reductions in NOx emissions in the Tampa Bay Airshed, compliance with the ambient air quality standards for ozone will be uncertain in the future because of continued commercial, industrial, population, traffic, and electrical demand growth in the region, coupled with meteorological conditions beyond the control of regulatory authorities or regulated industry.

Manatee Units 1 and 2 emit nitrogen oxides (NOx), a precursor to regional ozone formation, into the atmosphere of Manatee County and surrounding areas, including the Tampa Bay Airshed. The Manatee Plant, together with other regional power plants, commercial and industrial activities, and transportation, are the main sources of NOx affecting regional ozone formation in the Tampa Bay Airshed.

Installation of reburn technology in FPL's Manatee Units 1 and 2, by reducing NOx emissions, will help to ensure that the Tampa Bay Airshed will comply with the ozone ambient air quality standards established by the U.S. EPA and by the FDEP.

Q. Please describe FPL's Manatee Plant Units 1 & 2.

A. Units 1 and 2 are each 800 megawatt class fossil fuel-fired steam electric generating units located at FPL's Manatee Plant in Manatee County, Florida. The units have been in service since 1976 and 1977, firing residual fuel oil with a maximum sulfur content of one percent. FPL has recently decided to add natural gas as an additional permitted fuel for Units 1 and 2. The FDEP issued an air construction permit authorizing the addition of gas for these Units earlier this month.

Q. Please describe reburn technology.

A. This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced NOx control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process relies upon a reburn-like flue gas incineration technique that dates back to the late 1960s. Developments of this technique 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 Exhibit A, Document RRL-2, 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. Reburn fuel injectors will 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 have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, the reburn overfire air (OFA) ports will be located between the boiler wing walls and angled 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, or "add-on" pollution reduction or removal equipment.

Q. Has FPL estimated the cost of the proposed Project?

A. Yes. The use of reburn technology for Manatee Units 1 and 2 will require FPL to incur costs and expenses to install, operate and maintain that technology. FPL's capital cost estimate for the Manatee Reburn NOx Control Technology Project is $32.0 million for both units, to be incurred in 2003 through 2005. FPL projects to incur $5.0 million in 2003, $21.0 million in 2004, and $6.0 million in 2005. FPL has estimated this cost based on: a) prorating/scaling a leading vendor's budgetary estimate; b) prorating/scaling a recent firm-price proposal for oil & coal fired units for various plant sizes & applications; and c) escalated 1997 firm-price for the Manatee reburn conversion. O&M costs are estimated to be $250,000 in 2004, with an on-going O&M cost of $500,000 per year thereafter.

Q. Has FPL estimated how much will be spent on the Project in 2003?

A. FPL's capital cost estimate for 2003 is $5 million, which is for engineering related costs. The projected in-service date for Manatee Unit 1 is April 2004, and for Manatee Unit 2 is October 2004, therefore, no capital costs are included for recovery in 2003. FPL has not projected to incur any O&M costs in 2003.

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

A. FPL performed a cost/benefit analysis of proven technologies and determined that the reburn process is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2. FPL is currently preparing a formal request for proposal, which includes pricing options for turnkey and engineering/material to ensure the selection of the best offer.

Q. What alternatives did FPL consider?

A. FPL considered the following NOx control technologies for the Manatee Units;

Technology	Status
Overfire Air (OFA)	Not effective in current configuration
Reburning	Best option
Selective Non-Catalytic Reduction (SNCR)	Not feasible – high operating cost
Selective Catalytic Reduction (SCR)	Not Feasible-excessive capital & O&M costs

SPILL PREVENTION, CONTROL, AND COUNTERMEASURES PROJECT – SPCC

Q. Please describe the law or regulation requiring this Project.

A. The regulation is promulgated under the authority of the Clean Water Act and is published in Title 40 Code of Federal Regulation Part 112; Oil Pollution Prevention and Response; Non-Transportation-Related Onshore and Offshore Facilities; Final Rule (see Exhibit A, Document RRL-3). The rule is more commonly known as the Spill Prevention Control and Countermeasures (SPCC) Plan regulation or SPCC Rule. The final rule was published in the Federal Register (67 Fed. Reg. 47042) on July 17, 2002. The effective date of the regulation is August 16, 2002.

Q. How does this new law or regulation affect FPL?

A. FPL facilities that meet the general applicability standards as specified in the revised SPCC rule must comply with the rule's substantive oil spill prevention requirements. These FPL facilities include power plants, fuel oil terminal facilities, substations, recycling & distribution centers, and some service centers and office buildings. The rule clarifies for the first time that, facilities that also use oil in equipment such as transformers, turbine lube oil systems, and hydraulic oil systems are also subject to the rule and as such must also prepare and implement SPCC Plans.

Q. Please provide a summary of the SPCC requirements that apply to FPL's SPCC regulated facilities.

A. Oil–filled electrical equipment such as transformers, and electrical cable systems that could discharge to navigable waters must have appropriate containment and/or diversionary structures to prevent such a discharge. Bulk storage containers including piping must be provided with sufficiently impervious secondary containment (i.e., containment in which any discharge will not escape the containment system before cleanup occurs). Bulk storage containers include any container 55-gallons & greater.

Containment must be designed for the entire capacity of the largest single tank/container and have sufficient freeboard to contain precipitation. Expected impacts include diesel fuel storage tanks, turbine lube oil storage tanks and systems without sufficiently impervious containment, and regulated piping outside of secondary containment.

Tank truck unloading areas must be provided with a method of secondary containment that contains the largest compartment of a tank truck. The revised rule also requires that an interlock warning light or physical barrier system, warning signs, wheel chocks, or vehicle break interlock system in loading/unloading areas be provided to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines.

SPCC plan modifications will be required for existing facility SPCC Plans to address new requirements (e.g., a new PE certification to address applicability of industry standards, facility diagram indicating the location and contents of oil storage containers/tanks, piping & transfer stations, etc.).

Integrity testing of storage tanks must be conducted on a regular schedule or when materials repairs are conducted.

Storage tanks must be provided with one or more devices to alert operators of the level in the tanks (e.g., high level alarms with gauges, high-level pump cutoff device, etc).

All buried piping installed after August 16, 2002, must have protective wrappings and coating and be provided with cathodic protection. Facilities must establish a warning system (e.g., warning signs) to warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

The facilities' drainage systems must be designed from undiked areas with a potential for a discharge (e.g., piping located outside containment walls) to flow to ponds, lagoons, or catchment basins designed to return oil to the facility. If not engineered in this fashion, the final discharge of all ditches in the facility must be equipped with a diversion system to retain oil in the event of an uncontrolled discharge.

Q. Has FPL estimated the cost of the proposed Project?

A. FPL's capital cost estimate for the SPCC Project is $19.4 million to be incurred in 2003 through 2005. Estimated O&M costs are $211,000 to be incurred in 2002 through 2003.

Q. Has FPL estimated how much will be spent on the Project in 2002?

A. In the October – December 2002 timeframe, FPL has estimated to incur $36,000 of O&M costs associated with pre-engineering work for drainage in the containment areas.

Q. Has FPL estimated how much will be spent on the Project in 2003?

A. FPL has estimated $2.0 million of capital costs and $175,000 of O&M costs to be spent in 2003.

<u>**PIPELINE INTEGRITY MANAGEMENT PROGRAM (PIM) PROJECT**</u>

Q. Please briefly describe the PIM project.

A. On August 9, 2002, FPL filed its Estimated/Actual True-up for the period January 2002 through December 2002 which included FPL's request for recovery of the PIM Project through the ECR.

Per the U.S. Department of Transportation Regulation 49 CFR Part 195, operators with 500 or fewer mile of regulated pipelines are required to establish a program for managing the integrity of pipelines that could affect high consequence areas if a leak occurs. The objective of this requirement is to improve the integrity of pipeline systems in the U.S. in order to protect public safety, human health, and the environment.

FPL currently owns four hazardous liquid pipelines: the Martin 18 inch pipeline, the Martin 30 inch pipeline, the Manatee 16 inch pipeline, and the Dania Spur 8 inch pipeline. These four pipelines were included in the PIM Project filed on August 9, 2002.

Q. Please describe the change to the PIM Project which FPL is proposing.

A. The Dania Spur Pipeline has been removed from the PIM Project. The Dania Spur Pipeline was determined to be non-jurisdictional by the U.S. Department of Transportation Office of Pipeline Safety (OPS), based on the following conditions that are exempt under 49 CFR Part 195.1: The Dania Spur pipeline is operated as a low stress pipeline which serves manufacturing facilities such as power generation, is less that 1 mile in length, and does not cross an offshore area of a waterway currently used for commercial operation.

This determination is documented in a letter from the USDOT OPS dated January 10, 2001. If any of the specified conditions change, FPL would be immediately subject to the provisions of 49 CFR Part 195. OPS strongly recommended that FPL operate the pipeline as if it was regulated, and FPL has made a corporate commitment to do so.

Q. Has FPL revised the cost estimates of the PIM Project?

A. Yes. The estimated costs of the PIM Project have been revised due to the removal of the Dania Spur pipeline from the Project. Total project costs are now estimated to be $1,140,000 through 2004. Capital costs associated with metering equipment, piping changes and drainage structures for the Martin 30" pipeline are now estimated to be $810,000 for 2003. O&M costs for 2003 are now estimated to be $200,000 and O&M costs for 2004 are now estimated to be $50,000.

In 2002, FPL now projects O&M costs for the development of the written PIM plan and the identification of the high consequence areas to be $80,000.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

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

JANUARY 2003 – DECEMBER 2003

KMD-3
DOCKET NO. 020007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT ______
PAGES 1-63

Form 42-1P

Florida Power & Light Company

Environmental Cost Recovery Clause

Total Jurisdictional Amount to Be Recovered

For the Projected Period

January 2003 to December 2003

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)	2,755,165	1,157,598	720,184	4,632,947
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	3,810,237	2,606,317	0	6,416,554
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	6,565,402	3,763,915	720,184	11,049,501
2	True-up for Estimated Over/(Under) Recovery for the current period January 2002 - December 2002 (FORM 42-1E, Line 4, filed on August 9, 2002)	(4,996,960)	(2,119,407)	(683,059)	(7,799,426)
3	Final True-up Over/(Under) for the period January 2001 - December 2001 (FORM 42-1A, Line 5, filed on April 1, 2002)	0	0	0	0
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2003 - December 2003 (Line 1 - Line 2 - Line 3)	11,562,362	5,883,322	1,403,243	18,848,927
5a	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.01597)	11,747,013	5,977,279	1,425,653	19,149,944

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 2003 - December 2003

O&M Activities
(in Dollars)

Line	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	$5,800	$5,800	$87,832	$6,700	$6,200	$6,200	$118,532
3a Continuous Emission Monitoring Systems-O&M	31,941	34,768	94,281	31,951	34,778	94,201	321,920
4a Clean Closure Equivalency-O&M	0	0	0	0	0	0	0
5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	0	10,500	17,000	50,000	24,000	25,000	126,500
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	10,000	10,000	10,000	25,000	10,000	10,000	75,000
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	0	0	0	0	0	0	0
14 NPDES Permit Fees-O&M	112,900	0	0	0	0	0	112,900
17a Disposal of Noncontainerized Liquid Waste-O&M	10,000	47,500	29,000	22,500	41,000	18,000	168,000
19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	168,900	189,400	189,400	81,900	40,900	40,900	711,400
19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	65,900	121,900	121,900	120,500	54,600	53,000	537,800
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	10,000	50,000	25,000	0	0	0	85,000
NA Amortization of Gains on Sales of Emissions Allowances	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(259,134)
21 St Lucie Turtle Net	0	0	0	0	0	0	0
22 Pipeline Integrity Management	0	20,000	0	20,000	0	20,000	60,000
23 SPCC - Spill Prevention, Control & Countermeasures	0	0	0	43,750	43,750	43,750	131,250
2 Total of O&M Activities	$ 325,566	$ 399,993	$ 484,538	$ 312,426	$ 165,353	$ 221,176	$ 1,909,052
3 Recoverable Costs Allocated to Energy	$ 17,826	$ 62,460	$ 185,505	$ 50,436	$ 51,193	$ 87,493	$ 454,914
4a Recoverable Costs Allocated to CP Demand	$ 162,183	$ 171,476	$ 132,976	$ 203,433	$ 96,603	$ 116,126	$ 882,796
4b Recoverable Costs Allocated to GCP Demand	$ 145,557	$ 166,057	$ 166,057	$ 58,557	$ 17,557	$ 17,557	$ 571,342
5 Retail Energy Jurisdictional Factor	98 97818%	98 97818%	98 97818%	98 97818%	98 97818%	98 97818%	
6a Retail CP Demand Jurisdictional Factor	99 01742%	99 01742%	99 01742%	99 01742%	99 01742%	99 01742%	
6b Retail GCP Demand Jurisdictional Factor	100 00000%	100 00000%	100 00000%	100 00000%	100 00000%	100 00000%	
7 Jurisdictional Energy Recoverable Costs (A)	$ 17,643	$ 61,822	$ 183,610	$ 49,920	$ 50,670	$ 86,599	$ 450,264
8a Jurisdictional CP Demand Recoverable Costs (B)	$ 160,590	$ 169,791	$ 131,669	$ 201,434	$ 95,653	$ 114,985	$ 874,122
8b Jurisdictional GCP Demand Recoverable Costs (C)	$ 145,557	$ 166,057	$ 166,057	$ 58,557	$ 17,557	$ 17,557	$ 571,342
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 323,790	$ 397,670	$ 481,336	$ 309,911	$ 163,880	$ 219,141	$ 1,895,728

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 2003 - December 2003

O&M Activities
(in Dollars)

Line	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	$6,200	$6,200	$6,200	$6,200	$6,200	$2,059,223	$2,090,223	$2,208,755			$2,208,755
3a Continuous Emission Monitoring Systems-O&M	31,951	34,778	94,281	31,951	34,860	93,783	321,604	643,524			643,524
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	0	0	3,000	0	11,500	38,000	52,500	179,000	179,000		
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	10,000	10,000	10,000	20,000	10,000	15,000	75,000	150,000			150,000
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	0	0	0	0	0	50,000	50,000	50,000	50,000		
14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	112,900	112,900		
17a Disposal of Noncontainerized Liquid Waste-O&M	9,500	18,000	12,500	23,000	15,000	23,000	101,000	269,000			269,000
19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	19,900	19,900	40,900	40,900	88,900	78,400	288,900	1,000,300		1,000,300	
19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	10,500	10,500	10,500	10,500	62,500	35,600	140,100	677,900	625,754		52,146
19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	85,000	85,000		
NA Amortization of Gains on Sales of Emissions Allowances	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(259,134)	(518,268)			(518,268)
21 St Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
22 Pipeline Integrity Management	0	20,000	100,000	20,000	0	0	140,000	200,000	200,000		
23 SPCC - Spill Prevention, Control & Countermeasures	43,750	0	0	0	0	0	43,750	175,000	175,000		
2 Total of O&M Activities	$ 41,926	$ 29,503	$ 187,506	$ 62,676	$ 139,085	$2,303,131	$ 2,763,827	$ 4,672,879	$ 1,169,085	$ 720,184	$2,783,610
3 Recoverable Costs Allocated to Energy	$ 13,474	$ 24,801	$ 78,804	$ 36,974	$ 25,883	$2,148,760	$ 2,328,696	$ 2,783,610			
4a Recoverable Costs Allocated to CP Demand	$ 31,895	$ 8,145	$ 91,145	$ 8,145	$ 47,645	$ 99,314	$ 286,289	$ 1,169,085			
4b Recoverable Costs Allocated to GCP Demand	$ (3,443)	$ (3,443)	$ 17,557	$ 17,557	$ 65,557	$ 55,057	$ 148,842	$ 720,184			
5 Retail Energy Jurisdictional Factor	98 97818%	98 97818%	98 97818%	98 97818%	98 97818%	98 97818%					
6a Retail CP Demand Jurisdictional Factor	99 01742%	99 01742%	99 01742%	99 01742%	99 01742%	99 01742%					
6b Retail GCP Demand Jurisdictional Factor	100 00000%	100 00000%	100 00000%	100 00000%	100 00000%	100 00000%					
7 Jurisdictional Energy Recoverable Costs (A)	$ 13,336	$ 24,548	$ 77,999	$ 36,596	$ 25,619	$2,126,803	$ 2,304,901	$ 2,755,165			
8a Jurisdictional CP Demand Recoverable Costs (B)	$ 31,582	$ 8,065	$ 90,249	$ 8,065	$ 47,177	$ 98,338	$ 283,476	$ 1,157,598			
8b Jurisdictional GCP Demand Recoverable Costs (C)	$ (3,443)	$ (3,443)	$ 17,557	$ 17,557	$ 65,557	$ 55,057	$ 148,842	$ 720,184			
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 41,475	$ 29,170	$ 185,805	$ 62,218	$ 138,353	$2,280,198	$ 2,737,219	$ 4,632,947			

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 2003 - December 2003

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	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	$ 177,623	$ 176,731	$ 175,840	$ 174,948	$ 174,056	$ 173,164	$ 1,052,362
3b Continuous Emission Monitoring Systems-Capital	138,753	138,222	138,240	138,646	138,499	138,119	830,479
4b Clean Closure Equivalency-Capital	522	520	518	516	514	512	3,102
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	161,545	161,214	160,883	160,552	160,221	159,890	964,305
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	289	288	287	286	284	283	1,717
8b Oil Spill Cleanup/Response Equipment-Capital	11,703	11,637	11,570	11,503	11,436	11,370	69,219
10 Relocate Storm Water Runoff-Capital	1,005	1,003	1,000	998	995	993	5,994
NA SO2 Allowances-Negative Return on Investment	(11,817)	(11,474)	(11,130)	(10,786)	(10,443)	(11,690)	(67,340)
12 Scherer Discharge Pipeline-Capital	7,703	7,679	7,655	7,631	7,606	7,582	45,856
17b Disposal of Noncontainerized Liquid Waste-Capital	4,360	4,329	4,299	4,269	4,238	4,208	25,703
20 Wastewater Discharge Elimination &Reuse	17,399	17,345	17,292	17,238	17,184	17,130	103,588
21 St Lucie Turtle Net	7,104	7,091	7,078	7,066	7,053	7,040	42,432
22 Pipeline Integrity Management	0	0	0	0	4,433	8,855	13,288
23 SPCC - Spill Prevention, Control & Countermeasures	0	0	2,457	6,112	7,303	10,375	26,247
2 Total Investment Projects - Recoverable Costs	$ 516,189	$ 514,585	$ 515,989	$ 518,979	$ 523,379	$ 527,831	$ 3,116,952
3 Recoverable Costs Allocated to Energy	$ 320,838	$ 319,718	$ 319,338	$ 319,437	$ 319,133	$ 317,150	$ 1,915,613
4 Recoverable Costs Allocated to Demand	$ 195,351	$ 194,867	$ 196,651	$ 199,542	$ 204,246	$ 210,681	$ 1,201,339
5 Retail Energy Jurisdictional Factor	98.97818%	98 97818%	98.97818%	98.97818%	98.97818%	98.97818%	
6 Retail Demand Jurisdictional Factor	99.01742%	99 01742%	99.01742%	99 01742%	99.01742%	99.01742%	
7 Jurisdictional Energy Recoverable Costs (B)	$ 317,560	$ 316,451	$ 316,075	$ 316,172	$ 315,872	$ 313,909	$ 1,896,039
8 Jurisdictional Demand Recoverable Costs (C)	$ 193,431	$ 192,952	$ 194,719	$ 197,582	$ 202,240	$ 208,611	$ 1,189,535
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 510,991	$ 509,403	$ 510,794	$ 513,754	$ 518,112	$ 522,520	$ 3,085,574

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

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2003 - December 2003

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	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	$ 172,272	$ 171,380	$ 170,488	$ 169,597	$ 168,705	$ 167,813	$ 1,020,255	$ 2,072,617		$ 2,072,617
3b Continuous Emission Monitoring Systems-Capital	138,186	139,787	142,975	145,766	148,811	151,415	866,940	$ 1,697,419		1,697,419
4b Clean Closure Equivalency-Capital	510	508	506	504	502	500	3,030	$ 6,132	5,660	472
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	161,216	162,537	162,197	161,857	161,517	166,668	975,992	$ 1,940,297	1,791,043	149,254
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	282	281	280	278	277	276	1,674	$ 3,391	3,130	261
8b Oil Spill Cleanup/Response Equipment-Capital	11,303	12,970	13,591	13,516	15,175	15,788	82,343	$ 151,562	139,903	11,659
10 Relocate Storm Water Runoff-Capital	990	988	985	983	980	978	5,904	$ 11,898	10,983	915
NA SO2 Allowances-Negative Return on Investment	(12,938)	(12,594)	(12,251)	(11,907)	(11,563)	(11,220)	(72,473)	$ (139,813)		(139,813)
12 Scherer Discharge Pipeline-Capital	7,558	7,534	7,510	7,486	7,462	7,438	44,988	$ 90,844	83,856	6,988
17b Disposal of Noncontainerized Liquid Waste-Capital	4,177	4,147	4,117	4,086	4,056	4,025	24,608	$ 50,311	46,441	3,870
20 Wastewater Discharge Elimination &Reuse	17,077	17,023	16,969	16,916	16,862	16,808	101,655	$ 205,243	189,455	15,788
21 St. Lucie Turtle Net	7,027	7,014	7,001	6,988	6,975	6,962	41,967	$ 84,399	77,907	6,492
22 Pipeline Integrity Management	8,836	8,817	8,797	8,778	8,759	8,739	52,726	$ 66,014	60,936	5,078
23 SPCC - Spill Prevention, Control & Countermeasures	16,945	20,724	23,653	26,271	26,223	101,375	215,191	$ 241,438	222,866	18,572
2 Total Investment Projects - Recoverable Costs	$ 533,441	$ 541,116	$ 546,818	$ 551,119	$ 554,741	$ 637,565	$ 3,364,800	$ 6,481,752	$ 2,632,180	$ 3,849,572
3 Recoverable Costs Allocated to Energy	$ 315,668	$ 317,230	$ 320,105	$ 322,507	$ 325,091	$ 333,359	$ 1,933,959	$ 3,849,572		
4 Recoverable Costs Allocated to Demand	$ 217,773	$ 223,886	$ 226,713	$ 228,612	$ 229,650	$ 304,206	$ 1,430,841	$ 2,632,180		
5 Retail Energy Jurisdictional Factor	98.97818%	98.97818%	98 97818%	98 97818%	98.97818%	98.97818%				
6 Retail Demand Jurisdictional Factor	99.01742%	99.01742%	99.01742%	99 01742%	99.01742%	99.01742%				
7 Jurisdictional Energy Recoverable Costs (B)	$ 312,442	$ 313,989	$ 316,834	$ 319,212	$ 321,769	$ 329,952	$ 1,914,198	$ 3,810,237		
8 Jurisdictional Demand Recoverable Costs (C)	$ 215,633	$ 221,686	$ 224,486	$ 226,366	$ 227,394	$ 301,217	$ 1,416,782	$ 2,606,317		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 528,075	$ 535,675	$ 541,320	$ 545,578	$ 549,163	$ 631,169	$ 3,330,980	$ 6,416,554		

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 2003

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	$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 (B)	9,319,144	9,431,236	9,543,328	9,655,420	9,767,512	9,879,603	9,991,695	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$8,292,324	$8,180,232	$8,068,140	$7,956,048	$7,843,956	$7,731,865	$7,619,773	n/a
6	Average Net Investment		8,236,278	8,124,186	8,012,094	7,900,002	7,787,910	7,675,819	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		48,813	48,149	47,485	46,820	46,156	45,492	282,914
	b. Debt Component (Line 6 x 2 4358% x 1/12)		16,718	16,491	16,263	16,036	15,808	15,581	96,897
8.	Investment Expenses								
	a Depreciation (D)		112,092	112,092	112,092	112,092	112,092	112,092	672,551
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e. Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$177,623	$176,731	$175,840	$174,948	$174,056	$173,164	$1,052,362

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month acti
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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	$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 (B)	9,991,695	10,103,787	10,215,879	10,327,971	10,440,063	10,552,154	10,664,246	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$7,619,773	$7,507,681	$7,395,589	$7,283,497	$7,171,405	$7,059,314	$6,947,222	n/a
6	Average Net Investment		7,563,727	7,451,635	7,339,543	7,227,451	7,115,360	7,003,268	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		44,827	44,163	43,499	42,834	42,170	41,506	541,913
	b Debt Component (Line 6 x 2 4358% x 1/12)		15,353	15,126	14,898	14,671	14,443	14,215	185,602
8	Investment Expenses								
	a Depreciation (D)		112,092	112,092	112,092	112,092	112,092	112,092	1,345,102
	b Amortization								
	c Dismantlement								
	d. Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$172,272	$171,380	$170,488	$169,597	$168,705	$167,813	$2,072 617

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month act
(E) In June and July depreciation expense of $28,528.50 was inadvertently omitted from the Low Nox total This error was corrected in August ($28,258.50 x 2 = $57,057)

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

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		$0	$0	$78,000	$52,000	$0	$26,000	$156,000
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$12,995,106	12,995,106	12,995,106	13,073,106	13,125,106	13,125,106	13,151,106	0
3.	Less Accumulated Depreciation (B)	3,914,073	3,980,839	4,047,606	4,114,612	4,182,042	4,249,655	4,317,323	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$9,081,034	$9,014,267	$8,947,501	$8,958,495	$8,943,065	$8,875,451	$8,833,783	n/a
6.	Average Net Investment		9,047,650	8,980,884	8,952,998	8,950,780	8,909,258	8,854,617	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		53,622	53,226	53,061	53,048	52,802	52,478	318,236
	b Debt Component (Line 6 x 2 4358% x 1/12)		18,365	18,230	18,173	18,169	18,084	17,973	108,994
8.	Investment Expenses								
	a Depreciation (D)		66,766	66,766	67,006	67,430	67,613	67,668	403,250
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$138,753	$138,222	$138,240	$138,646	$138,499	$138,119	$830,481

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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		$66,100	$275,600	$330,700	$212,400	$346,400	$132,200	$1,519,400
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$13,151,106	13,217,206	13,492,806	13,823,506	14,035,906	14,382,306	14,514,506	n/a
3	Less. Accumulated Depreciation (B)	4,317,323	4,385,231	4,453,924	4,523,945	4,595,158	4,667,765	4,741,655	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$8,833,783	$8,831,976	$9,038,883	$9,299,562	$9,440,749	$9,714,542	$9,772,852	n/a
6.	Average Net Investment		8,832,879	8,935,429	9,169,222	9,370,155	9,577,645	9,743,697	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		52,349	52,957	54,342	55,533	56,763	57,747	647,927
	b Debt Component (Line 6 x 2 4358% x 1/12)		17,929	18,137	18,612	19,020	19,441	19,778	221,912
8.	Investment Expenses								
	a Depreciation (D)		67,908	68,693	70,021	71,213	72,607	73,890	827,582
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$138,186	$139,787	$142,975	$145,766	$148,811	$151,415	$1,697,421

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity.
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

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	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3	Less Accumulated Depreciation (B)	23,882	24,126	24,370	24,615	24,859	25,103	25,348	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$34,984	$34,740	$34,496	$34,251	$34,007	$33,763	$33,518	n/a
6	Average Net Investment		34,862	34,618	34,373	34,129	33,885	33,640	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		207	205	204	202	201	199	1,218
	b Debt Component (Line 6 x 2 4358% x 1/12)		71	70	70	69	69	68	417
8	Investment Expenses								
	a Depreciation (D)		244	244	244	244	244	244	1,466
	b. Amortization								
	c Dismantlement								
	d. Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$522	$520	$518	$516	$514	$512	$3,102

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity.
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3	Less: Accumulated Depreciation (B)	25,348	25,592	25,836	26,081	26,325	26,569	26,814	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$33,518	$33,274	$33,030	$32,785	$32,541	$32,297	$32,052	n/a
6	Average Net Investment		33,396	33,152	32,907	32,663	32,419	32,174	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		198	196	195	194	192	191	2,384
	b. Debt Component (Line 6 x 2 4358% x 1/12)		68	67	67	66	66	65	816
8.	Investment Expenses								
	a Depreciation (D)		244	244	244	244	244	244	2,932
	b. Amortization								
	c. Dismantlement								
	d Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$510	$508	$506	$504	$502	$500	$6,132

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

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						$0		$0
	c. Retirements								
	d Other (A)								
2.	Plant-In-Service/Depreciation Base	$13,520,438	13,520,438	13,520,438	13,520,438	13,520,438	13,520,438	13,520,438	n/a
3	Less: Accumulated Depreciation (B)	(1,576,631)	(1,535,040)	(1,493,448)	(1,451,857)	(1,410,265)	(1,368,674)	(1,327,083)	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$15,097,069	$15,055,478	$15,013,886	$14,972,295	$14,930,703	$14,889,112	$14,847,520	n/a
6.	Average Net Investment		15,076,273	15,034,682	14,993,090	14,951,499	14,909,908	14,868,316	
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		89,351	89,105	88,858	88,612	88,365	88,119	532,409
	b Debt Component (Line 6 x 2.4358% x 1/12)		30,602	30,518	30,433	30,349	30,265	30,180	182,348
8	Investment Expenses								
	a. Depreciation (D)		41,591	41,591	41,591	41,591	41,591	41,591	249,549
	b Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$161,545	$161,214	$160,883	$160,552	$160,221	$159,890	$964,305

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the mont
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior mon
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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		$270,000	$0	$0	$0	$0	$860,000	$1,130,000
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$13,520,438	13,790,438	13,790,438	13,790,438	13,790,438	13,790,438	14,650,438	n/a
3	Less Accumulated Depreciation (B)	(1,327,083)	(1,284,906)	(1,242,145)	(1,199,383)	(1,156,622)	(1,113,860)	(1,069,021)	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$14,847,520	$15,075,344	$15,032,583	$14,989,821	$14,947,060	$14,904,298	$15,719,459	n/a
6	Average Net Investment		14,961,432	15,053,963	15,011,202	14,968,440	14,925,679	15,311,878	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		88,670	89,219	88,965	88,712	88,459	90,747	1,067,182
	b Debt Component (Line 6 x 2 4358% x 1/12)		30,369	30,557	30,470	30,383	30,297	31,081	365,505
8	Investment Expenses								
	a Depreciation (D)		42,176	42,761	42,761	42,761	42,761	44,840	507,610
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$161,216	$162,537	$162,197	$161,857	$161,517	$166,668	$1,940,297

Notes

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior mont
(E) To correct depreciation expense for Work Order No 5367/70/913/06 from 1994 to present A retirement made in 1994 was not removed from the depreciation calculation causing excess depreciation to be calculated

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

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	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3	Less Accumulated Depreciation (B)	13,765	13,917	14,070	14,222	14,375	14,527	14,680	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$17,265	$17,113	$16,960	$16,808	$16,655	$16,503	$16,350	n/a
6.	Average Net Investment		17,189	17,037	16,884	16,732	16,579	16,426	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		102	101	100	99	98	97	598
	b Debt Component (Line 6 x 2.4358% x 1/12)		35	35	34	34	34	33	205
8	Investment Expenses								
	a. Depreciation (D)		153	153	153	153	153	153	915
	b. Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$289	$288	$287	$286	$284	$283	$1,717

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3	Less: Accumulated Depreciation (B)	14,680	14,832	14,985	15,138	15,290	15,443	15,595	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$16,350	$16,198	$16,045	$15,892	$15,740	$15,587	$15,435	n/a
6	Average Net Investment		16,274	16,121	15,969	15,816	15,664	15,511	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		96	96	95	94	93	92	1,163
	b Debt Component (Line 6 x 2 4358% x 1/12)		33	33	32	32	32	31	398
8.	Investment Expenses								
	a. Depreciation (D)		153	153	153	153	153	153	1,831
	b. Amortization								
	c. Dismantlement								
	d Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$282	$281	$280	$278	$277	$276	$3,391

Notes.

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) 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 2003

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		$0	$0	$0	$0	$0	$0	$0
	c Retirements								
	d Other (A)								
2.	Plant-In-Service/Depreciation Base	$782,623	782,623	782,623	782,623	782,623	782,623	782,623	n/a
3	Less Accumulated Depreciation (B)	361,326	369,711	378,096	386,480	394,865	403,250	411,634	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$421,297	$412,912	$404,527	$396,143	$387,758	$379,373	$370,989	n/a
6	Average Net Investment		417,104	408,720	400,335	391,950	383,566	375,181	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		2,472	2,422	2,373	2,323	2,273	2,224	14,087
	b Debt Component (Line 6 x 2 4358% x 1/12)		847	830	813	796	779	762	4,825
8	Investment Expenses								
	a Depreciation (D)		8,385	8,385	8,385	8,385	8,385	8,385	50,308
	b Amortization								
	c Dismantlement								
	d. Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,703	$11,637	$11,570	$11,503	$11,436	$11,370	$69,219

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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		$0	$175,000	$0	$0	$175,000	$0	$350,000
	c. Retirements								
	d Other (A)								
2.	Plant-In-Service/Depreciation Base	$782,623	782,623	957,623	957,623	957,623	1,132,623	1,132,623	n/a
3.	Less Accumulated Depreciation (B)	411,634	420,019	429,445	438,872	448,298	458,766	469,234	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$370,989	$362,604	$528,178	$518,751	$509,325	$673,857	$663,389	n/a
6.	Average Net Investment		366,796	445,391	523,465	514,038	591,591	668,623	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		2,174	2,640	3,102	3,047	3,506	3,963	32,518
	b. Debt Component (Line 6 x 2 4358% x 1/12)		745	904	1,063	1,043	1,201	1,357	11,137
8.	Investment Expenses								
	a Depreciation (D)		8,385	9,426	9,426	9,426	10,468	10,468	107,907
	b. Amortization								
	c. Dismantlement								
	d Property Expenses								
	e. Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$11,303	$12,970	$13,591	$13,516	$15,175	$15,788	$151,562

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

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	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3	Less: Accumulated Depreciation (B)	30,767	31,081	31,395	31,709	32,023	32,337	32,651	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$87,027	$86,713	$86,399	$86,085	$85,771	$85,457	$85,143	n/a
6	Average Net Investment		86,870	86,556	86,242	85,928	85,614	85,300	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		515	513	511	509	507	506	3,061
	b Debt Component (Line 6 x 2.4358% x 1/12)		176	176	175	174	174	173	1,048
8.	Investment Expenses								
	a Depreciation (D)		314	314	314	314	314	314	1,885
	b. Amortization								
	c Dismantlement								
	d Property Expenses								
	e. Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$1,005	$1,003	$1,000	$998	$995	$993	$5,994

Notes:
(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3	Less Accumulated Depreciation (B)	32,651	32,966	33,280	33,594	33,908	34,222	34,536	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$85,143	$84,828	$84,514	$84,200	$83,886	$83,572	$83,258	n/a
6	Average Net Investment		84,985	84,671	84,357	84,043	83,729	83,415	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		504	502	500	498	496	494	6,055
	b Debt Component (Line 6 x 2.4358% x 1/12)		173	172	171	171	170	169	2,074
8.	Investment Expenses								
	a Depreciation (D)		314	314	314	314	314	314	3,769
	b Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$990	$988	$985	$983	$980	$978	$11,898

Notes:

(A) N/A

(B) N/A

(C) 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 a 11% return on equity

(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity

(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

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	$864,260	864,260	864,260	864,260	864 260	864,260	864 260	n/a
3	Less Accumulated Depreciation (B)	275,308	278,337	281,366	284,395	287,423	290,452	293,481	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$588,952	$585,923	$582,894	$579,865	$576,837	$573,808	$570,779	n/a
6	Average Net Investment		587,438	584,409	581,380	578,351	575,322	572,293	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		3,482	3,464	3,446	3,428	3,410	3,392	20,620
	b Debt Component (Line 6 x 2.4358% x 1/12)		1,192	1,186	1,180	1,174	1,168	1,162	7,062
8	Investment Expenses								
	a Depreciation (D)		3,029	3,029	3,029	3,029	3,029	3,029	18,173
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$7,703	$7,679	$7 655	$7,631	$7,606	$7,582	$45,856

Notes:
(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3	Less: Accumulated Depreciation (B)	293,481	296,510	299,539	302,568	305,597	308,626	311,655	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$570,779	$567,750	$564,721	$561,692	$558,663	$555,634	$552,605	n/a
6	Average Net Investment		569,264	566,235	563,207	560,178	557,149	554 120	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		3,374	3,356	3,338	3,320	3,302	3,284	40,593
	b Debt Component (Line 6 x 2 4358% x 1/12)		1,156	1,149	1,143	1,137	1,131	1,125	13,903
8.	Investment Expenses								
	a Depreciation (D)		3,029	3,029	3,029	3,029	3,029	3,029	36,347
	b Amortization								
	c. Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$7,558	$7,534	$7,510	$7,486	$7,462	$7,438	$90,844

Notes
(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) 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 2003

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	$694,142	694,142	694,142	694,142	694,142	694,142	694,142	n/a
3	Less Accumulated Depreciation (B)	4,049	5,669	7,289	8,909	10,529	12,149	13,769	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$690,093	$688,473	$686,853	$685,233	$683,613	$681,993	$680,373	n/a
6.	Average Net Investment		689,283	687,663	686,043	684,423	682,803	681,183	
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		4,085	4,076	4,066	4,056	4,047	4,037	24,367
	b Debt Component (Line 6 x 2.4358% x 1/12)		1,399	1,396	1,393	1,389	1,386	1,383	8,345
8	Investment Expenses								
	a Depreciation (D)		1,620	1,620	1,620	1,620	1,620	1,620	9,720
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,104	$7,091	$7,078	$7,066	$7,053	$7,040	$42,432

Notes.
(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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	$694,142	694,142	694,142	694,142	694,142	694,142	694,142	n/a
3.	Less Accumulated Depreciation (B)	$13,769	15,389	17,008	18,628	20,248	21,867	23,487	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$680,373	$678,753	$677,133	$675,514	$673,894	$672,274	$670,655	n/a
6	Average Net Investment		679,563	677,943	676,324	674,704	673,084	671,465	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		4,028	4,018	4,008	3,999	3,989	3,980	48,388
	b Debt Component (Line 6 x 2.4358% x 1/12)		1,379	1,376	1,373	1,370	1,366	1,363	16,573
8.	Investment Expenses								
	a. Depreciation (D)		1,620	1,620	1,620	1,620	1,620	1,620	19,438
	b Amortization								
	c. Dismantlement								
	d Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,027	$7,014	$7,001	$6,988	$6,975	$6,962	$84,399

Notes
(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

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	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3	Less: Accumulated Depreciation (B)	241,264	245,084	248,904	252,724	256,544	260,364	264,184	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$69,745	$65,925	$62,105	$58,285	$54,465	$50,645	$46,825	n/a
6.	Average Net Investment		67,835	64,015	60,195	56,375	52,555	48,735	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		402	379	357	334	311	289	2,073
	b. Debt Component (Line 6 x 2.4358% x 1/12)		138	130	122	114	107	99	710
8	Investment Expenses								
	a Depreciation (D)		3,820	3,820	3,820	3,820	3,820	3,820	22,920
	b Amortization								
	c Dismantlement								
	d. Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,360	$4,329	$4,299	$4,269	$4,238	$4,208	$25,703

Notes:
(A) N/A
(B) N/A
(C) 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 a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

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	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3.	Less Accumulated Depreciation (B)	264,184	268,004	271,824	275,644	279,464	283,284	287,104	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$46,825	$43,005	$39,185	$35,365	$31,545	$27,725	$23,905	n/a
6.	Average Net Investment		44,915	41,095	37,275	33,455	29,635	25,815	
7.	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		266	244	221	198	176	153	3,330
	b. Debt Component (Line 6 x 2 4358% x 1/12)		91	83	76	68	60	52	1,141
8.	Investment Expenses								
	a Depreciation (D)		3,820	3,820	3,820	3,820	3,820	3,820	45,840
	b. Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,177	$4,147	$4,117	$4,086	$4,056	$4,025	$50,311

Notes.
(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/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		$0	$0	$0	$0	$0	$0	$0
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	n/a
3	Less Accumulated Depreciation (B)	222,099	228,848	235,597	242,346	249,095	255,844	262,593	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$1,341,896	$1,335,147	$1,328,398	$1,321,649	$1,314,900	$1,308,151	$1,301,402	n/a
6	Average Net Investment		1,338,521	1,331,772	1,325,023	1,318,274	1,311,525	1,304,776	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		7,933	7,893	7,853	7,813	7,773	7,733	46,997
	b Debt Component (Line 6 x 2 4358% x 1/12)		2,717	2,703	2,690	2,676	2,662	2,648	16,096
8	Investment Expenses								
	a Depreciation (D)		6,749	6,749	6,749	6,749	6,749	6,749	40,494
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$17,399	$17,345	$17,292	$17,238	$17,184	$17,130	$103,588

Notes

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/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	$0
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	n/a
3	Less Accumulated Depreciation (B)	$262,593	269,342	276,091	282,841	289,590	296,339	303,088	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$1,301,402	$1,294,653	$1,287,903	$1,281,154	$1,274,405	$1,267,656	$1,260,907	n/a
6	Average Net Investment		1,298,027	1,291,278	1,284,529	1,277,780	1,271,031	1,264,282	
7	Return on Average Net Investment								
	Equity Component grossed up for taxes (C)		7,693	7,653	7,613	7,573	7,533	7,493	92,555
	Debt Component (Line 6 x 2.4358% x 1/12)		2,635	2,621	2,607	2,594	2,580	2,566	31,700
8	Investment Expenses								
	a Depreciation (D)		6,749	6,749	6,749	6,749	6,749	6,749	80,988
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$17,077	$17,023	$16,969	$16,916	$16,862	$16,808	$205,243

Notes

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management Program (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		$0	$0	$0	$0	$810,000	$0	$810,000
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$0	0	0	0	0	810,000	810,000	n/a
3	Less Accumulated Depreciation (B)	0	0	0	0	0	1,215	3,645	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$808,785	$806,355	n/a
6	Average Net Investment		0	0	0	0	404,393	807,570	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		0	0	0	0	2,397	4,786	7,183
	b Debt Component (Line 6 x 2 4358% x 1/12)		0	0	0	0	821	1,639	2,460
8	Investment Expenses								
	a Depreciation (D)		0	0	0	0	1,215	2,430	3,645
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$4,433	$8,855	$13,288

Notes:

(A) N/A

(B) N/A

(C) 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 a 11% return on equity

(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity

(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project Pipeline Integrity Management Program (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	$810,000
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$810,000	810,000	810,000	810,000	810,000	810,000	810,000	n/a
3	Less Accumulated Depreciation (B)	$3,645	6,075	8,505	10,935	13,365	15,795	18,225	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$806,355	$803,925	$801,495	$799,065	$796,635	$794,205	$791,775	n/a
6	Average Net Investment		805,140	802,710	800,280	797,850	795,420	792,990	
7	Return on Average Net Investment								
	Equity Component grossed up for taxes (C)		4,772	4,757	4,743	4,729	4,714	4,700	35,597
	Debt Component (Line 6 x 2 4358% x 1/12)		1,634	1,629	1,624	1,620	1,615	1,610	12,192
8	Investment Expenses								
	a Depreciation (D)		2,430	2,430	2,430	2,430	2,430	2,430	18,225
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$8,836	$8,817	$8,797	$8,778	$8,759	$8,739	$66,014

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention, Control, and Countermeasures (SPCC) (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		$0	$0	$502,250	$200,000	$0	$622,250	$1,324,500
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$0	0	0	502,250	702,250	702,250	1,324,500	n/a
3	Less Accumulated Depreciation (B)	0	0	0	460	1,789	3,526	5,876	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$501,790	$700,461	$698,724	$1,318,624	n/a
6	Average Net Investment		0	0	250,895	601,125	699 592	1 008,674	
7	Return on Average Net Investment								
	a Equity Component grossed up for taxes (C)		0	0	1,487	3,563	4,146	5,978	15,174
	b Debt Component (Line 6 x 2 4358% x 1/12)		0	0	509	1,220	1,420	2,047	5,197
8	Investment Expenses								
	a Depreciation (D)		0	0	460	1 329	1,737	2,350	5,876
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$2,457	$6,112	$7,303	$10,375	$26,247

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project. Spill Prevention, Control, and Countermeasures (SPCC) (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		$660,000	$50,000	$537,250	$0	$0	$12,768,250	$15,340,000
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$1,324,500	1,984,500	2,034,500	2,571,750	2,571,750	2,571,750	15,340,000	n/a
3	Less Accumulated Depreciation (B)	$5,876	9,719	14,551	20,017	26,009	32,001	62,495	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 - 3 + 4)	$1,318,624	$1,974,781	$2,019,949	$2,551,733	$2,545,741	$2,539,749	$15,277,505	n/a
6	Average Net Investment		1,646,702	1,997,365	2,285,841	2,548,737	2,542,745	8,908,627	
7	Return on Average Net Investment								
	Equity Component grossed up for taxes (C)		9,759	11,838	13,547	15,105	15,070	52,798	133,291
	Debt Component (Line 6 x 2 4358% x 1/12)		3,343	4,054	4,640	5,174	5,161	18,083	45,652
8	Investment Expenses								
	a Depreciation (D)		3,843	4,832	5,466	5,992	5,992	30,494	62,495
	b Amortization								
	c Dismantlement								
	d Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$16,945	$20,724	$23,653	$26,271	$26,223	$101,375	$241,438

Notes:

(A) N/A
(B) N/A
(C) 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 a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

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

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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	(1,506,826)	(1,463,637)	(1,420,448)	(1,377,259)	(1,334,070)	(1,290,881)	(1,647,692)	
2	Total Working Capital	($1,506,826)	($1,463,637)	($1,420,448)	($1,377,259)	($1,334,070)	($1,290,881)	($1,647,692)	
3	Average Net Working Capital Balance		(1,485,231)	(1,442,042)	(1,398,853)	(1,355,664)	(1,312,475)	(1,469,286)	
4	Return on Average Net Working Capital Balance								
	a Equity Component grossed up for taxes (A)		(8,802)	(8,546)	(8,290)	(8,034)	(7,779)	(8,708)	(50,160)
	b Debt Component (Line 3 x 2.4358% x 1/12)		(3,015)	(2,927)	(2,839)	(2,752)	(2,664)	(2,982)	(17,180)
5	Total Return Component		($11,817)	($11,474)	($11,130)	($10,786)	($10,443)	($11,690)	($67,340) (D)
6	Expense Dr (Cr)								
	a 411 800 Gains from Dispositions of Allowances		(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(259,134)
	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)		($43,189)	($43,189)	($43,189)	($43,189)	($43,189)	($43,189)	($259,134) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(55,006)	(54,663)	(54,319)	(53,975)	(53,632)	(54,879)	
	a Recoverable Costs Allocated to Energy		(55,006)	(54,663)	(54,319)	(53,975)	(53,632)	(54,879)	
	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)		(54,202)	(53,863)	(53,525)	(53,186)	(52,847)	(54,077)	(321,700)
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($54,202)	($53,863)	($53,525)	($53,186)	($52,847)	($54,077)	($321,700)

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 a 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 2003

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	(1,647,692)	(1,604,503)	(1,561,313)	(1,518,124)	(1,474,935)	(1,431,746)	(1,388,557)	
2	Total Working Capital	($1,647,692)	($1,604,503)	($1,561,313)	($1,518,124)	($1,474,935)	($1,431,746)	($1,388,557)	
3	Average Net Working Capital Balance		(1,626,097)	(1,582,908)	(1,539,719)	(1,496,530)	(1,453,341)	(1,410,152)	
4	Return on Average Net Working Capital Balance								
	a Equity Component grossed up for taxes (A)		(9,637)	(9,381)	(9,125)	(8,869)	(8,613)	(8,357)	(104,144)
	b Debt Component (Line 6 x 2 358% x 1/12)		(3,301)	(3,213)	(3,125)	(3,038)	(2,950)	(2,862)	(35,669)
5	Total Return Component		($12,938)	($12,594)	($12,251)	($11,907)	($11,563)	($11,220)	($139,813)
6	Expense Dr (Cr)								
	a 411 800 Gains from Dispositions of Allowances		(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(518,269)
	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)		($43,189)	($43,189)	($43,189)	($43,189)	($43,189)	($43,189)	($518,269)
8	Total System Recoverable Expenses (Lines 5+7)		($56,127)	($55,783)	($55,440)	($55,096)	($54,752)	($54,409)	
	a Recoverable Costs Allocated to Energy		(56,127)	(55,783)	(55,440)	(55,096)	(54,752)	(54,409)	
	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)		(55,306)	(54,968)	(54,629)	(54,290)	(53,952)	(53,613)	(648,458)
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($55,306)	($54,968)	($54,629)	($54,290)	($53,952)	($53,613)	($648,458)

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 a 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
PROJECT DESCRIPTION AND PROGRESS

Project Title: Air Operating Permit Fees – O&M
Project No. 1
Project Description:

The Clean Air Act Amendments of 1990, Public Law 101-549, and Florida Statutes 403.0872, require each major source of air pollution to pay an annual license fee. The amount of the fee is based on each source's previous year's emissions. It is calculated by multiplying the applicable annual operation license fee factor ($25 per ton for both Florida and Georgia) by the tons of each air pollutant emitted by the unit during the previous year and regulated in each unit's air operating permit, up to a total of 4,000 tons per pollutant. The major regulated pollutants at the present time are sulfur dioxide (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:

(April 15, 2002 to June 30, 2002)
The monthly fees for 2001 emissions at Scherer have been paid and continue to be paid in 2002. 2001 air operating permit fees for the Florida facilities were calculated in January 2002 utilizing 2001 operating information. They were paid to the FDEP in March 2002.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $15,852 or 0.8% higher than previously projected. This variance is primarily due to fluctuations in permit fees for 2002, which are based on tons of pollutants discharged from the fossil fuel fired power plants during the previous year. These emissions are proportionate to the type of fuel used at each plant. These variables fluctuate daily, based on weather conditions and fuel type.

Project Progress Summary:

2001 air operating permit fees for the Florida facilities were calculated in January 2002 utilizing 2001 operating information. They were paid to the FDEP in March 2002.

Project Projections:

Estimated project expenditures for the period January 2003 through December 2003 are expected to be $2,208,755.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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:

(April 15, 2002 to June 30, 2002)
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:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $46,593 or 11.4% lower than previously projected. This variance is primarily due to the delay in the payment of the CEMS software support service contract. The original software vendor, KVB-Entertec has been acquired by GE Energy Services. FPL is in the final stages of the negotiations with GE Energy Services to determine the terms and conditions of the software support contract, therefore the scheduled payment has not yet been made.

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 2003 through December 2003 are expected to be $643,524. The increase in cost for 2003 is due to the increase in number of analyzers required by the repowering at Sanford , Fort Myers and peaking units at Martin Plant.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M
Project No. 5a
Project Description:

Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

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:

(April 15, 2002 to June 30, 2002)
Work continued on miscellaneous maintenance of above ground fuel storage tank and pipe systems. All required tank registration fees have been paid for 2002.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $20,640 or 42.8% higher than previously projected. The majority of the storage tank work was performed at the beginning of the year versus the latter part of the year, as originally projected.

Project Projections:

Estimated project fiscal expenditures for the period January 2003 through December 2003 are expected to be $179,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil Spill Cleanup/Response Equipment - O&M
Project No. 8a
Project Description:

The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments:

(April 15, 2002 to June 30, 2002)
Plan updates have continued to be performed and filed for all sites as required, routine maintenance of oil spill equipment has been on-going throughout the year, spill management team drill, equipment deployment drills have been performed throughout the system as well as oil spill training for team members.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $6,480 or 9.8% lower than previously projected.

Project Projections:

Estimated project fiscal expenditures for the period January 2003 through December 2003 are expected to be $150,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: RCRA Corrective Action - O & M
Project No. 13
Project Description:

Under the Hazardous and Solid Waste Amendments of 1984 (amending the Resource Conservation and Recovery Act, or RCRA), the U.S. EPA has the authority; to require hazardous waste treatment facilities to investigate whether there have been releases of hazardous waste or constituents from non-regulated units on the facility site. If contamination is found to be present at levels that represent a threat to human health or the environment, the facility operator can be required to undertake "corrective action" to remediate the contamination. In April 1994, the U.S. EPA advised FPL that it intended to initiate RCRA Facility Assessments (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:

No further action has been received for Ft. Myers. Visual Site Inspections have been conducted at Martin, Cape Canaveral, and Putnam. The following is the completion status of source removal activities at each site: St. Lucie 100%, Martin 100%, Fort Myers 100%, Port Everglades 100%, Cape Canaveral 100%, Manatee 100%, Sanford 90%. Additional source removal activity was identified at Putnam and Turkey Point.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $25,000 or 71.4% lower than previously projected. This variance is primarily due to a decrease in projected cost associated with the preparation of a facility for an expected assessment by the EPA, which did not occur. These expenditures are contingent upon receiving notification from EPA of its intent to move forward with the process.

Project Progress Summary:

This is an ongoing project. The next Visual Site Inspection date is pending. Completion of the RFA reports for Martin, Cape Canaveral, and Putnam is being negotiated.

Project Projection:
Estimated project expenditures for the period of January 2003 through December 2003 are expected to be $50,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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

In compliance with State of Florida Rule 62-4.052, 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:

(April 15, 2002 to June 30, 2002)
The NPDES permit fees were paid to the FDEP during the month of January. Fees associated with the Industrial wastewater permit renewal application have been paid for Port Everglades Plant.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $13,500 or 45.0% higher than previously projected. This variance is primarily due to incurring costs for a permit renewal for Cape Canaveral Plant in 2002 rather than 2003 as originally projected. Additionally, payments were made for sodium exemptions at Cape Canaveral Plant, Fort Myers Plant, and Port Everglades Plant that were not included in the original projections.

Project Progress Summary:

The NPDES permit fees were paid to the FDEP during the month of January. Fees associated with the Industrial Wastewater Permit renewal application fees have been paid for Port Everglades Plant, and will be paid for Cape Canaveral, Lauderdale, Riviera and Fort Myers Plants.

Project Projections:

Estimated project expenditures for the period January 2003 through December 2003 are expected to be $112,900.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Disposal of Noncontainerized Liquid Waste - O&M
Project 17a
Project Description:

FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:

(April 15, 2002 to June 30, 2002)
Ash de-watering has been completed at the following sites at the Cape Canaveral and Ft. Myers Plants. Currently processing material at Port Everglades. Ash de-watering at Manatee Plant was completed before April 16, 2002.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $33,268 or 12.7% lower than previously projected. This variance is primarily due to the deferral of the ash-processing project at Riviera Plant to 2003 due to conflicts in scheduling the ash press. This equipment separates ash from the water and is integral to the job. The ash press will not be available for use at the Riviera Plant until late December 2002.

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 2003 through December 2003 are expected to be $269,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Substation Pollutant Discharge Prevention & Removal - O&M
Project No. 19a, 19b, 19c

Project Description:

Florida Statute Chapter 376 Pollutant Discharge Prevention and Removal requires that any person discharging a pollutant, defined as any commodity made from oil or gas, shall immediately undertake to contain, remove and abate the discharge to the satisfaction of the department. Florida Statute Chapter 403 holds it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. 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:

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 369 transformers have been regasketed and 777 transformers have been encapsulated.

Project Fiscal Expenditures:

Project expenditures are estimated to be:
- 19a $321,104 or 26.4% lower than previously projected
- 19b $88,240 or 13.5% lower than previously projected
- 19c 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 2003 through December 2003 are expected to be $1,117,968.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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:

Facility specific BMP3 Action Plans have been approved by the Florida Department of Environmental Protection. The agency has also determined that a BMP3 Plan is not required for the Turkey Point Plant. Remediation of ash basin is 100% complete, ash waste water chemical treatment system is 100% complete, major surface water discharges at two facilities have been reduced, recycling systems at four facilities have been installed. The Martin Plant wastewater treatment system was completed in 2000.

Project Fiscal Expenditures:

Project expenditures are estimated to be $0.

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 2003 through December 2003 are expected to be $85,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) – O&M
Project No.22
Project Description:

FPL is required to develop a written pipeline integrity management program for its hazardous liquid 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:

(April 15, 2002 to June 30, 2002)

The PIM project is in its early stages and FPL has put together a cost estimate and a Request For Proposal (RFP) with detailed specifications. The RFP will be issued for program development and will be awarded to the lowest or best qualified bidder. In-house resources and current contracted resources will be utilized where practical and cost effective. Capital improvement bids will also be awarded through RFPs based on cost effectiveness.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $80,000 of O&M to be spent late in the year. This is for identifying which pipeline segments could affect a high consequence area and a baseline assessment.

Project Projections:

Estimated project fiscal expenditures for the period January 2003 through December 2003 are expected to be $200,000 of O&M.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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:

(April 15, 2002 to June 30, 2002)
The SPCC project is in its early stages and FPL has put together cost estimates and the company will be performing a more detailed analysis in the coming months to examine the cost and effectiveness of other construction alternatives.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are for the pre-engineering and are projected to be $36,000 of O&M. This will be spent late in the year for 2002.

Project Progress Summary:

FPL has conducted a preliminary analysis of its affected facilities and has developed a cost estimate to bring these facilities into compliance with the final rule. The company will be fine tuning its cost projections in the coming months.

Project Projections:

Estimated project expenditures for the period January 2003 through December 2003 are expected to be $175,000 of O&M.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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:

(April 15, 2002 to June 30, 2002)
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:

(April 15, 2002 to December 31, 2002)
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 2003 through December 2003 are expected to be $0 of O&M.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low NO_x Burner Technology (LNBT) – Capital
Project No. 2

Project Description:

Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce NO_x emissions. The Dade, Broward and Palm Beach county areas were classified as "moderate non-attainment" by the EPA. FPL has six units in this affected area.

LNBT meets the requirement to reduce NO_x emissions by delaying the mixing of the fuel and air at the burner, creating a staged combustion process along the length of the flame. NO_x formation is reduced because peak flame temperatures and availability of oxygen for combustion is reduced in the initial stages.

Project Accomplishments:

All six units are in service and operational.

Project Fiscal Expenditures:

Project expenditures are estimated to be $6,218 or 0.4% higher than originally projected. The variance is not significantly different from the projection.

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 fiscal expenditures for the period January 2003 through December 2003 are expected to be $2,072,617.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring System (CEMS) – Capital
Project No. 3b
Project Description:

The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping and reporting of 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:

(April 15, 2002 to June 30, 2002)
NOx Continuos Emission Monitoring systems were installed at Martin Plant Units # 1 and #2. The analyzers for all other plants will be installed in 2003.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $50,494 or 4.0% lower than originally projected due to the retirements resulting from the Ft. Myers and Sanford repowering projects that were not included in the original projections. By reducing net plant, these retirements caused both the annual depreciation and return on investment to be lower than projected.

Project Progress Summary:

NOx Continuos Emission Monitoring systems were installed at Martin Plant Units # 1 and #2.

Project Projections:

Estimated project expenditures for the period January 2003 through December 2003 are expected to be $1,697,419.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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.

(April 15, 2002 to December 31, 2002)
Project Accomplishments:

No additional wells were installed and the activities are complete.

(April 15, 2002 to December 31, 2002)
Project Fiscal Expenditures:
Project expenditures are estimated to be $17 or 0.4% higher than originally projected. The variance is not significantly different from the projection.

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 2003 through December 2003 are expected to be $6,132.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital
Project No. 5b
Project Description:

Florida Administrative Code (F.A.C.) Chapter 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

The capital project associated with complying with the new standards includes the installation of items for each tank such as liners, cathodic projection systems and tank high-level alarms.

Project Accomplishments:
(April 15, 2002 to June 30, 2002)
Initial preparation for the installation of a double bottom on Tank 901 at the Port Everglades Terminal has begun. This project should be completed by the end of the year.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are estimated to be $22,867 or 1.7% lower than originally projected due to the retirements resulting from the Ft. Myers and Sanford repowering projects that were not included in the original projections. By reducing net plant, these retirements caused both the annual depreciation and return on investment to be lower than projected.

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 need to 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. FPL planned to install an internal storage tank liner in Tank B at the Riviera plant in 2002, but the project has been postponed until 2003.

Project Projections:

Estimated project fiscal expenditures for the period January 2003 through December 2003 are expected to be $1,940,297.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Turbine Lube Oil Underground Piping to Above Ground - Capital
Project No. 7
Project Description:

In accordance with criteria contained in Chapter 62-762 of the Florida Administrative Code (F.A.C.) for storage of pollutants, FPL initiated the replacement of underground Turbine Lube Oil piping to above ground installations at the St. Lucie Nuclear Power Plant.

Project Accomplishments:

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:

Project expenditures are estimated to be $10 or 0.4% higher than originally projected. The variance is not significantly different from the projection.

Project Progress Summary:

This project is complete.

Project Projections:

Estimated project fiscal expenditures (depreciation and return) for the period of January 2003 through December 2003 are expected to be $3,391.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil Spill Cleanup/Response Equipment – Capital
Project No. 8b
Project Description:

The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments:

Oil spill equipment has been maintained, upgraded and replaced to meet federal and state requirements.

Project Fiscal Expenditures:

(April 15, 2002 to June 30, 2002)
Expenditures are estimated to be $5,457 or 5.3% less than previously projected. The variance is not significantly different from the projection.

Project Progress Summary:

(April 15, 2002 to December 31, 2002)
All deadlines, both state and federal, have been met. Ongoing annual costs will consist of equipment upgrades/replacements.

Project Projections:

Estimated project fiscal expenditures (depreciation and return) for the period January 2003 through December 2003 are expected to be $151,562.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Storm Water Runoff - Capital
Project No. 10
Project Description:

The new National Pollutant Discharge Elimination System (NPDES) permit, Permit No. FL0002206, for the St. Lucie Plant, issued by the United States Environmental Protection Agency contains new effluent discharge limitations for industrial-related storm water from the paint and land utilization building areas. The new requirements become effective on January 1, 1994. As a result of these new requirements, the effected areas will be surveyed, graded, excavated and paved as necessary to clean and redirect the storm water runoff. The storm water runoff will be collected and discharged to existing water catch basins on site.

Project Accomplishments:

The rerouting of the storm water runoff was completed in April 1994.

Project Fiscal Expenditures:

Project expenditures are estimated to be $35 or 0.4% more than previously projected. No significant variance is anticipated.

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 2003 through December 2003 are expected to be $11,898.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Sulfur Dioxide (SO_2) Allowances - Capital
Project No. 11
Project Description:

The Clean Air Act Amendments of 1990, Public Law 101-549 Section 416, established a U.S. Environmental Protection Agency (EPA) tracking system for managing domestic air pollution sources emitting sulfur dioxide, a regulated pollutant. In brief, historical power plant operating data regarding fuel type and quantity burned are used to determine the tons of annual SO_2 emissions that may be emitted from a facility or generating system. Each ton of SO_2 to be emitted corresponds to one EPA SO_2 emissions "allowance". These allowances may be freely bought and sold, within certain constraints, to minimize the cost of environmental compliance using a free market-based approach. FPL was allocated allowances for its use beginning in the year 2000. However, the law established a mechanism for an annual auction to assure the availability of these required allowances to parties that had no historical emissions or that needed to increase their total annual emissions now or in the future. To establish a "pool" of available allowances for the auction, EPA withheld a percentage of all allowances, with compensation for the original allowance holder to be made following their sale to the highest bidder at the annual auction.

Project Accomplishments:

Auctions of emission allowances were conducted by the U.S. EPA in March of 1993 through and including March of 2000. FPL has received the revenues for the allowances sold at these auctions and is recording the proceeds as negative return on investment in accordance with the Commission's order dated April 6, 1994. In 2000 FPL began using SO2 allowances in accordance with Phase II of the Clean Air Act Amendments.

Project Fiscal Expenditures:

Project expenditures are estimated to be $35,621 or 46.4% higher than originally projected, is due to higher than anticipated gains from the DOE sales of emission allowances in 2002.

Project Progress Summary:

Revenues from the eight auctions of allowances held to date have been received and are being recorded in accordance with the Commission's order.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2003 through December 2003 are expected to be ($139,813).

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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

On March 16, 1992, pursuant to the provisions of the Georgia Water 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:

The discharge pipeline was placed in-service in February 1994.

Project Fiscal Expenditures:

Project expenditures are estimated to be $265 or 0.4% higher than originally projected. No significant variance is anticipated.

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 2003 through December 2003 are expected to be $90,844.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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:

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:

Project expenditures are estimated to be $155 or 0.4% higher than originally projected. No significant variance is anticipated.

Project Progress Summary:

This project is complete.

Project Projections:

Estimated project fiscal expenditures for the period January 2003 through December 2003 are expected to be $50,311.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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:

Facility specific BMP3 Action Plans have been approved by the Florida Department of Environmental Protection. The agency has also determined that a BMP3 Plan is not required for the Turkey Point Plant. Ash basin lining is 100% complete, ash waste water chemical treatment system is 90% complete, major surface water discharges at two facilities have been reduced, recycling systems at four facilities have been installed.

Project Fiscal Expenditures:

Project expenditures are estimated to be $600 or 0.4% higher than originally projected. No significant variance is anticipated.

Project Progress Summary:

Developments since our last filing 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. 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 expenditures for the period January 2003 through December 2003 are expected to be $ 205,243.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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:

(April 15, 2002 to June 30, 2002)
The Turtle Net Project has been fully developed and is currently being implemented. FPL expects to complete the installation of the Turtle Net Project in September 2002.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures are projected to be $17,975 of capital. This will be spent late in the year for 2002.

Project Progress Summary:

Request for proposals for the Turtle Net project have been issued and we are waiting on a final response from the vendors.

Project Projections:

Estimated project expenditures for the period January 2003 through December 2003 are expected to be $84,399 of capital.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) – Capital
Project No.22
Project Description:

FPL is required to develop a written pipeline integrity management program for its hazardous liquid pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments:

(April 15, 2002 to June 30, 2002)
The PIM project is in its early stages and FPL has put together a cost estimate and a Request For Proposal (RFP) with detailed specifications. The RFP will be issued for program development and will be awarded to the lowest or best qualified bidder. In-house resources and current contracted resources will be utilized where practical and cost effective. Capital improvement bids will also be awarded through RFPs based on cost effectiveness.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures will be $0 for capital.

Project Projections:

Estimated project fiscal expenditures for the period January 2003 through December 2003 are expected to be $66,014 of capital.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (Spill Prevention, Control, and Countermeasures) – Capital
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:

(April 15, 2002 to June 30, 2002)
The SPCC project is in its early stages and FPL has put together cost estimates and the company will be performing a more detailed analysis in the coming months to examine the cost and effectiveness of other construction alternatives.

Project Fiscal Expenditures:

(April 15, 2002 to December 31, 2002)
Project expenditures will be $0 for capital.

Project Progress Summary:

FPL has conducted a preliminary analysis of its affected facilities and has developed a cost estimate to bring these facilities into compliance with the final rule. The company will be fine tuning its cost projections in the coming months.

Project Projections:

Estimated project expenditures for the period January 2003 through December 2003 are expected to be $241,438 of Capital.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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:

(April 15, 2002 to June 30, 2002)
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:

(April 15, 2002 to December 31, 2002)
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 2003 through December 2003 are expected to be $0 of Capital.

Form 42-6P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2003 to December 2003

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	62.616%	58 009%	50,471,039,871	9,201,377	9,932,149	1.094827488	1.073915762	54,201,645,242	10,073,920	10,873,990	52.79090%	57.91053%	56 36791%
GS1	68.676%	57.609%	5,793,955,050	963,088	1,148,100	1.094827488	1.073915762	6,222,219,653	1,054,415	1,256,971	6.06027%	6.06137%	6.51581%
GSD1	73.696%	66 863%	21,865,398,011	3,386,955	3,733,067	1 094723515	1 073838681	23,479,910,160	3,707,779	4,086,676	22 86878%	21 31439%	21.18425%
OS2	105 150%	26 201%	21,461,533	2,330	9,351	1 058079498	1.045886865	22,446,335	2,465	9,894	0 02186%	0 01417%	0.05129%
GSLD1/CS1	79.862%	68 285%	9,938,252,955	1,420,580	1,661,419	1 093047752	1 072600787	10,659,777,941	1,552,762	1,816,010	10 38233%	8 92614%	9.41372%
GSLD2/CS2	81.244%	72 422%	1,553,745,889	218,316	244,909	1.086373648	1.067208009	1,658,170,057	237,173	266,063	1 61501%	1 36340%	1 37920%
GSLD3/CS3	91.313%	78.567%	184,853,894	23,110	26,859	1.027640676	1.022546340	189,021,673	23,749	27,601	0 18410%	0.13652%	0 14308%
SST1T	121.750%	33 372%	156,626,041	14,686	53,577	1 027640676	1 022546340	160,157,385	15,092	55,058	0.15599%	0.08676%	0 28541%
SST1D	80.766%	66 089%	63,776,080	9,014	11,016	1.064343398	1.052972443	67,154,455	9,594	11,725	0.06541%	0.05515%	0.06078%
CILCD/CILCG	91 552%	84 170%	3,410,560,539	425,259	462,557	1.082801970	1 064967021	3,632,134,497	460,471	500,858	3.53760%	2 64704%	2 59632%
CILCT	100 265%	87 192%	1,577,785,426	179,636	206,571	1 027640676	1 022546340	1,613,358,713	184,601	212,281	1 57137%	1.06119%	1 10041%
MET	67 043%	56.592%	91,521,766	15,584	18,461	1 058079498	1.045886865	95,721,413	16,489	19,533	0.09323%	0 09479%	0.10125%
OL1/SL1/PL1	145.050%	46 921%	538,601,843	42,388	131,037	1.094827488	1.073915762	578,413,009	46,408	143,463	0 56336%	0.26678%	0.74367%
SL2	99.861%	97.729%	85,846,103	9,813	10,027	1.094827488	1 073915762	92,191,483	10,744	10,978	0.08979%	0.06176%	0.05691%
TOTAL			95,753,425,000	15,912,136	17,649,100			102,672,322,014	17,395,662	19,291,101	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 2003 through December 2003
(4) Calculated. (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2001 demand losses
(7) Based on 2001 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 2003 to December 2003

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	52.79090%	57.91053%	56.36791%	$6,201,354	$3,461,474	$803,611	$10,466,439	50,471,039,871	0.00021
GS1	6.06027%	6.06137%	6.51581%	$711,901	$362,305	$92,893	$1,167,099	5,793,955,050	0.00020
GSD1	22.86878%	21.31439%	21.18425%	$2,686,399	$1,274,020	$302,014	$4,262,433	21,865,398,011	0.00019
OS2	0.02186%	0 01417%	0 05129%	$2,568	$847	$731	$4,146	21,461,533	0.00019
GSLD1/CS1	10.38233%	8 92614%	9 41372%	$1,219,613	$533,541	$134,207	$1,887,361	9,938,252,955	0.00019
GSLD2/CS2	1.61501%	1 36340%	1.37920%	$189,716	$81,494	$19,663	$290,873	1,553,745,889	0.00019
GSLD3/CS3	0.18410%	0.13652%	0.14308%	$21,626	$8,160	$2,040	$31,826	184,853,894	0.00017
SST1T	0 15599%	0.08676%	0.28541%	$18,324	$5,186	$4,069	$27,579	156,626,041	0.00018
SST1D	0.06541%	0.05515%	0.06078%	$7,683	$3,297	$867	$11,847	63,776,080	0.00019
CILC D/CILC G	3.53760%	2.64704%	2 59632%	$415,562	$158,221	$37,014	$610,797	3,410,560,539	0.00018
CILC T	1.57137%	1 06119%	1.10041%	$184,589	$63,430	$15,688	$263,707	1,577,785,426	0.00017
MET	0.09323%	0 09479%	0.10125%	$10,952	$5,666	$1,444	$18,062	91,521,766	0.00020
OL1/SL1/PL1	0 56336%	0.26678%	0.74367%	$66,178	$15,946	$10,602	$92,726	538,601,843	0.00017
SL2	0 08979%	0.06176%	0.05691%	$10,548	$3,692	$811	$15,051	85,846,103	0.00018
TOTAL				$11,747,013	$5,977,279	$1,425,653	$19,149,944	95,753,425,000	0 00020

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 2003 through December 2003
(9) Col 7 / Col 8 x 100

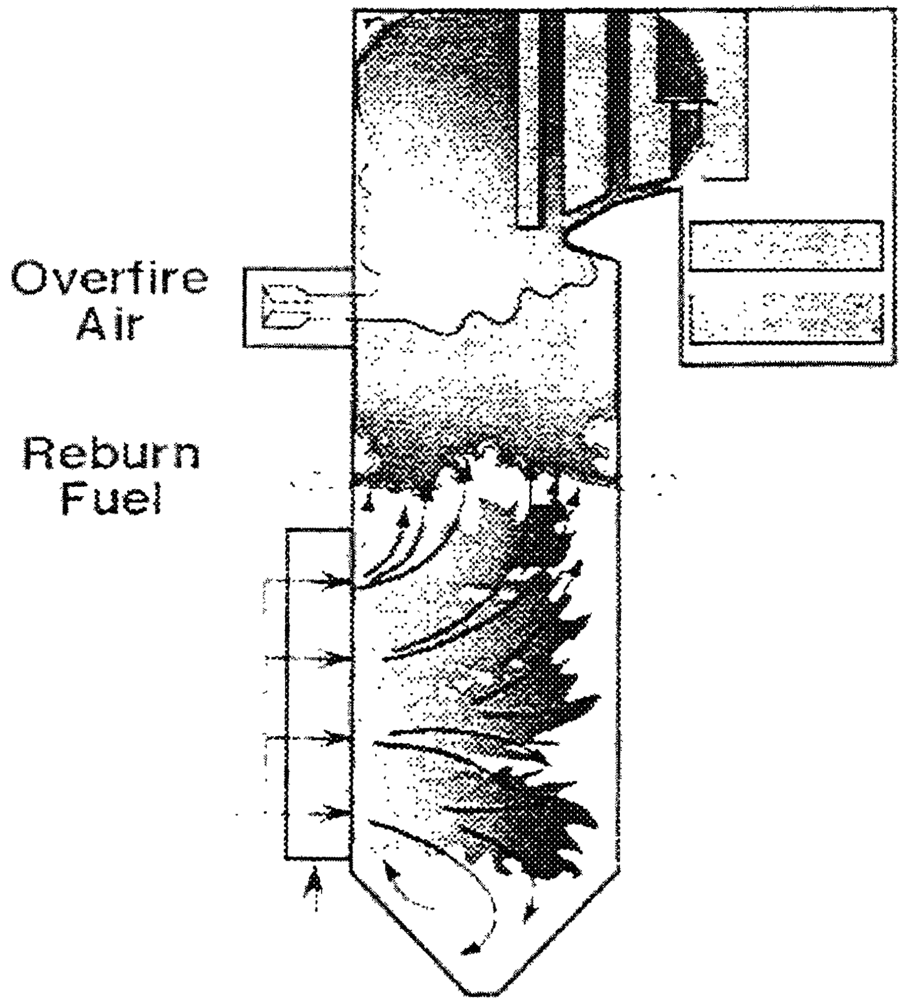

Figure 1 Conceptual application of reburning in a utility boiler

RRL-2
DOCKET NO. 020007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGE 1-1

ENVIRONMENTAL PROTECTION AGENCY

40 CFR PART 112

RRL-3
DOCKET NO. 020007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT ______________
PAGES 1-14

112 of the Code of Federal Regulations, is amended as follows:

PART 112—OIL POLLUTION PREVENTION

1. The authority for part 112 continues to read as follows:

Authority: 33 U.S.C. 1251 *et seq.*; 33 U.S.C 2720; E.O. 12777 (October 18, 1991), 3 CFR, 1991 Comp., p. 351.

2. Part 112 is amended by designating §§ 112.1 through 112.7 as subpart A, adding a subpart heading and revising newly designated subpart A to read as follows:

Subpart A—Applicability, Definitions, and General Requirements For All Facilities and All Types of Oils

Sec.

Subpart A—Applicability, Definitions, and General Requirements for All Facilities and All Types of Oils

§ 112.1 General applicability.

(a)(1) This part establishes procedures, methods, equipment, and other requirements to prevent the discharge of oil from non-transportation-related onshore and offshore facilities into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act).

(2) As used in this part, words in the singular also include the plural and words in the masculine gender also include the feminine and vice versa, as the case may require.

(b) Except as provided in paragraph (d) of this section, this part applies to any owner or operator of a non-transportation-related onshore or offshore facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location, could reasonably be expected to discharge oil in quantities that may be harmful, as described in part 110 of this chapter, into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act) that has oil in:

(1) Any aboveground container;

(2) Any completely buried tank as defined in § 112.2;

(3) Any container that is used for standby storage, for seasonal storage, or for temporary storage, or not otherwise "permanently closed" as defined in § 112.2;

(4) Any "bunkered tank" or "partially buried tank" as defined in § 112.2, or any container in a vault, each of which is considered an aboveground storage container for purposes of this part.

(c) As provided in section 313 of the Clean Water Act (CWA), departments, agencies, and instrumentalities of the Federal government are subject to this part to the same extent as any person.

(d) Except as provided in paragraph (f) of this section, this part does not apply to:

(1) The owner or operator of any facility, equipment, or operation that is not subject to the jurisdiction of the Environmental Protection Agency (EPA) under section 311(j)(1)(C) of the CWA, as follows:

(i) Any onshore or offshore facility, that due to its location, could not reasonably be expected to have a discharge as described in paragraph (b) of this section. This determination must be based solely upon consideration of the geographical and location aspects of the facility (such as proximity to navigable waters or adjoining shorelines, land contour, drainage, etc.) and must exclude consideration of manmade features such as dikes, equipment or other structures, which may serve to restrain, hinder, contain, or otherwise prevent a discharge as described in paragraph (b) of this section.

(ii) Any equipment, or operation of a vessel or transportation-related onshore or offshore facility which is subject to the authority and control of the U.S. Department of Transportation, as defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of EPA, dated November 24, 1971 (Appendix A of this part).

(iii) Any equipment, or operation of a vessel or onshore or offshore facility which is subject to the authority and control of the U.S. Department of Transportation or the U.S. Department of the Interior, as defined in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (Appendix B of this part).

(2) Any facility which, although otherwise subject to the jurisdiction of EPA, meets both of the following requirements:

(i) The completely buried storage capacity of the facility is 42,000 gallons or less of oil. For purposes of this exemption, the completely buried storage capacity of a facility excludes the capacity of a completely buried tank, as defined in § 112.2, and connected underground piping, underground ancillary equipment, and containment systems, that is currently subject to all of the technical requirements of part 280 of this chapter or all of the technical requirements of a State program approved under part 281 of this chapter. The completely buried storage capacity of a facility also excludes the capacity of a container that is "permanently closed," as defined in § 112.2.

(ii) The aggregate aboveground storage capacity of the facility is 1,320 gallons or less of oil. For purposes of this exemption, only containers of oil with a capacity of 55 gallons or greater are counted. The aggregate aboveground storage capacity of a facility excludes the capacity of a container that is "permanently closed," as defined in § 112.2.

(3) Any offshore oil drilling, production, or workover facility that is subject to the notices and regulations of the Minerals Management Service, as specified in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (Appendix B of this part).

(4) Any completely buried storage tank, as defined in § 112.2, and connected underground piping, underground ancillary equipment, and containment systems, at any facility, that is subject to all of the technical requirements of part 280 of this chapter or a State program approved under part 281 of this chapter, except that such a tank must be marked on the facility diagram as provided in § 112.7(a)(3), if

the facility is otherwise subject to this part.

(5) Any container with a storage capacity of less than 55 gallons of oil.

(6) Any facility or part thereof used exclusively for wastewater treatment and not used to satisfy any requirement of this part. The production, recovery, or recycling of oil is not wastewater treatment for purposes of this paragraph.

(e) This part establishes requirements for the preparation and implementation of Spill Prevention, Control, and Countermeasure (SPCC) Plans. SPCC Plans are designed to complement existing laws, regulations, rules, standards, policies, and procedures pertaining to safety standards, fire prevention, and pollution prevention rules. The purpose of an SPCC Plan is to form a comprehensive Federal/State spill prevention program that minimizes the potential for discharges. The SPCC Plan must address all relevant spill prevention, control, and countermeasures necessary at the specific facility. Compliance with this part does not in any way relieve the owner or operator of an onshore or an offshore facility from compliance with other Federal, State, or local laws.

(f) Notwithstanding paragraph (d) of this section, the Regional Administrator may require that the owner or operator of any facility subject to the jurisdiction of EPA under section 311(j) of the CWA prepare and implement an SPCC Plan, or any applicable part, to carry out the purposes of the CWA.

(1) Following a preliminary determination, the Regional Administrator must provide a written notice to the owner or operator stating the reasons why he must prepare an SPCC Plan, or applicable part. The Regional Administrator must send such notice to the owner or operator by certified mail or by personal delivery. If the owner or operator is a corporation, the Regional Administrator must also mail a copy of such notice to the registered agent, if any and if known, of the corporation in the State where the facility is located.

(2) Within 30 days of receipt of such written notice, the owner or operator may provide information and data and may consult with the Agency about the need to prepare an SPCC Plan, or applicable part.

(3) Within 30 days following the time under paragraph (b)(2) of this section within which the owner or operator may provide information and data and consult with the Agency about the need to prepare an SPCC Plan, or applicable part, the Regional Administrator must make a final determination regarding whether the owner or operator is required to prepare and implement an SPCC Plan, or applicable part. The Regional Administrator must send the final determination to the owner or operator by certified mail or by personal delivery. If the owner or operator is a corporation, the Regional Administrator must also mail a copy of the final determination to the registered agent, if any and if known, of the corporation in the State where the facility is located.

(4) If the Regional Administrator makes a final determination that an SPCC Plan, or applicable part, is necessary, the owner or operator must prepare the Plan, or applicable part, within six months of that final determination and implement the Plan, or applicable part, as soon as possible, but not later than one year after the Regional Administrator has made a final determination.

(5) The owner or operator may appeal a final determination made by the Regional Administrator requiring preparation and implementation of an SPCC Plan, or applicable part, under this paragraph. The owner or operator must make the appeal to the Administrator of EPA within 30 days of receipt of the final determination under paragraph (b)(3) of this section from the Regional Administrator requiring preparation and/or implementation of an SPCC Plan, or applicable part. The owner or operator must send a complete copy of the appeal to the Regional Administrator at the time he makes the appeal to the Administrator. The appeal must contain a clear and concise statement of the issues and points of fact in the case. In the appeal, the owner or operator may also provide additional information. The additional information may be from any person. The Administrator may request additional information from the owner or operator. The Administrator must render a decision within 60 days of receiving the appeal or additional information submitted by the owner or operator and must serve the owner or operator with the decision made in the appeal in the manner described in paragraph (f)(1) of this section.

§ 112.2 Definitions.

For the purposes of this part:

Adverse weather means weather conditions that make it difficult for response equipment and personnel to clean up or remove spilled oil, and that must be considered when identifying response systems and equipment in a response plan for the applicable operating environment. Factors to consider include significant wave height as specified in Appendix E to this part (as appropriate), ice conditions, temperatures, weather-related visibility, and currents within the area in which the systems or equipment is intended to function.

Alteration means any work on a container involving cutting, burning, welding, or heating operations that changes the physical dimensions or configuration of the container.

Animal fat means a non-petroleum oil, fat, or grease of animal, fish, or marine mammal origin.

Breakout tank means a container used to relieve surges in an oil pipeline system or to receive and store oil transported by a pipeline for reinjection and continued transportation by pipeline.

Bulk storage container means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container.

Bunkered tank means a container constructed or placed in the ground by cutting the earth and re-covering the container in a manner that breaks the surrounding natural grade, or that lies above grade, and is covered with earth, sand, gravel, asphalt, or other material. A bunkered tank is considered an aboveground storage container for purposes of this part.

Completely buried tank means any container completely below grade and covered with earth, sand, gravel, asphalt, or other material. Containers in vaults, bunkered tanks, or partially buried tanks are considered aboveground storage containers for purposes of this part.

Complex means a facility possessing a combination of transportation-related and non-transportation-related components that is subject to the jurisdiction of more than one Federal agency under section 311(j) of the CWA.

Contiguous zone means the zone established by the United States under Article 24 of the Convention of the Territorial Sea and Contiguous Zone, that is contiguous to the territorial sea and that extends nine miles seaward from the outer limit of the territorial area.

Contract or other approved means means:

(1) A written contractual agreement with an oil spill removal organization that identifies and ensures the availability of the necessary personnel and equipment within appropriate response times; and/or

(2) A written certification by the owner or operator that the necessary personnel and equipment resources, owned or operated by the facility owner or operator, are available to respond to a discharge within appropriate response times; and/or

(3) Active membership in a local or regional oil spill removal organization that has identified and ensures adequate access through such membership to necessary personnel and equipment to respond to a discharge within appropriate response times in the specified geographic area; and/or

(4) Any other specific arrangement approved by the Regional Administrator upon request of the owner or operator.

Discharge includes, but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil, but excludes discharges in compliance with a permit under section 402 of the CWA; discharges resulting from circumstances identified, reviewed, and made a part of the public record with respect to a permit issued or modified under section 402 of the CWA, and subject to a condition in such permit; or continuous or anticipated intermittent discharges from a point source, identified in a permit or permit application under section 402 of the CWA, that are caused by events occurring within the scope of relevant operating or treatment systems. For purposes of this part, the term discharge shall not include any discharge of oil that is authorized by a permit issued under section 13 of the River and Harbor Act of 1899 (33 U.S.C. 407).

Facility means any mobile or fixed, onshore or offshore building, structure, installation, equipment, pipe, or pipeline (other than a vessel or a public vessel) used in oil well drilling operations, oil production, oil refining, oil storage, oil gathering, oil processing, oil transfer, oil distribution, and waste treatment, or in which oil is used, as described in Appendix A to this part. The boundaries of a facility depend on several site-specific factors, including, but not limited to, the ownership or operation of buildings, structures, and equipment on the same site and the types of activity at the site.

Fish and wildlife and sensitive environments means areas that may be identified by their legal designation or by evaluations of Area Committees (for planning) or members of the Federal On-Scene Coordinator's spill response structure (during responses). These areas may include wetlands, National and State parks, critical habitats for endangered or threatened species, wilderness and natural resource areas, marine sanctuaries and estuarine reserves, conservation areas, preserves, wildlife areas, wildlife refuges, wild and scenic rivers, recreational areas, national forests, Federal and State lands that are research national areas, heritage program areas, land trust areas, and historical and archaeological sites and parks. These areas may also include unique habitats such as aquaculture sites and agricultural surface water intakes, bird nesting areas, critical biological resource areas, designated migratory routes, and designated seasonal habitats.

Injury means a measurable adverse change, either long- or short-term, in the chemical or physical quality or the viability of a natural resource resulting either directly or indirectly from exposure to a discharge, or exposure to a product of reactions resulting from a discharge.

Maximum extent practicable means within the limitations used to determine oil spill planning resources and response times for on-water recovery, shoreline protection, and cleanup for worst case discharges from onshore non-transportation-related facilities in adverse weather. It includes the planned capability to respond to a worst case discharge in adverse weather, as contained in a response plan that meets the requirements in § 112.20 or in a specific plan approved by the Regional Administrator.

Navigable waters means the waters of the United States, including the territorial seas.

(1) The term includes:

(i) All waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters subject to the ebb and flow of the tide;

(ii) All interstate waters, including interstate wetlands;

(iii) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, wetlands, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation, or destruction of which could affect interstate or foreign commerce including any such waters:

(A) That are or could be used by interstate or foreign travelers for recreational or other purposes; or

(B) From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or,

(C) That are or could be used for industrial purposes by industries in interstate commerce;

(iv) All impoundments of waters otherwise defined as waters of the United States under this section;

(v) Tributaries of waters identified in paragraphs (1)(i) through (iv) of this definition;

(vi) The territorial sea; and

(vii) Wetlands adjacent to waters (other than waters that are themselves wetlands) identified in paragraph (1) of this definition.

(2) Waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of the CWA (other than cooling ponds which also meet the criteria of this definition) are not waters of the United States. Navigable waters do not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other Federal agency, for the purposes of the CWA, the final authority regarding CWA jurisdiction remains with EPA.

Non-petroleum oil means oil of any kind that is not petroleum-based, including but not limited to: Fats, oils, and greases of animal, fish, or marine mammal origin; and vegetable oils, including oils from seeds, nuts, fruits, and kernels.

Offshore facility means any facility of any kind (other than a vessel or public vessel) located in, on, or under any of the navigable waters of the United States, and any facility of any kind that is subject to the jurisdiction of the United States and is located in, on, or under any other waters.

Oil means oil of any kind or in any form, including, but not limited to: fats, oils, or greases of animal, fish, or marine mammal origin; vegetable oils, including oils from seeds, nuts, fruits, or kernels; and, other oils and greases, including petroleum, fuel oil, sludge, synthetic oils, mineral oils, oil refuse, or oil mixed with wastes other than dredged spoil.

Oil Spill Removal Organization means an entity that provides oil spill response resources, and includes any for-profit or not-for-profit contractor, cooperative, or in-house response resources that have been established in a geographic area to provide required response resources.

Onshore facility means any facility of any kind located in, on, or under any land within the United States, other than submerged lands.

Owner or operator means any person owning or operating an onshore facility or an offshore facility, and in the case of any abandoned offshore facility, the person who owned or operated or maintained the facility immediately prior to such abandonment.

Partially buried tank means a storage container that is partially inserted or constructed in the ground, but not entirely below grade, and not completely covered with earth, sand, gravel, asphalt, or other material. A partially buried tank is considered an aboveground storage container for purposes of this part.

Permanently closed means any container or facility for which:

(1) All liquid and sludge has been removed from each container and connecting line; and

(2) All connecting lines and piping have been disconnected from the container and blanked off, all valves (except for ventilation valves) have been closed and locked, and conspicuous signs have been posted on each container stating that it is a permanently closed container and noting the date of closure.

Person includes an individual, firm, corporation, association, or partnership.

Petroleum oil means petroleum in any form, including but not limited to crude oil, fuel oil, mineral oil, sludge, oil refuse, and refined products.

Production facility means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil, or associated storage or measurement, and located in a single geographical oil or gas field operated by a single operator.

Regional Administrator means the Regional Administrator of the Environmental Protection Agency, in and for the Region in which the facility is located.

Repair means any work necessary to maintain or restore a container to a condition suitable for safe operation, other than that necessary for ordinary, day-to-day maintenance to maintain the functional integrity of the container and that does not weaken the container.

Spill Prevention, Control, and Countermeasure Plan; SPCC Plan, or Plan means the document required by § 112.3 that details the equipment, workforce, procedures, and steps to prevent, control, and provide adequate countermeasures to a discharge.

Storage capacity of a container means the shell capacity of the container.

Transportation-related and non-transportation-related, as applied to an onshore or offshore facility, are defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, dated November 24, 1971, (Appendix A of this part).

United States means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Commonwealth of the Northern Mariana Islands, Guam, American Samoa, the U.S. Virgin Islands, and the Pacific Island Governments.

Vegetable oil means a non-petroleum oil or fat of vegetable origin, including but not limited to oils and fats derived from plant seeds, nuts, fruits, and kernels.

Vessel means every description of watercraft or other artificial contrivance used, or capable of being used, as a means of transportation on water, other than a public vessel.

Wetlands means those areas that are inundated or saturated by surface or groundwater at a frequency or duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include playa lakes, swamps, marshes, bogs, and similar areas such as sloughs, prairie potholes, wet meadows, prairie river overflows, mudflats, and natural ponds.

Worst case discharge for an onshore non-transportation-related facility means the largest foreseeable discharge in adverse weather conditions as determined using the worksheets in Appendix D to this part.

§ 112.3 Requirement to prepare and implement a Spill Prevention, Control, and Countermeasure Plan.

The owner or operator of an onshore or offshore facility subject to this section must prepare a Spill Prevention, Control, and Countermeasure Plan (hereafter "SPCC Plan" or "Plan")," in writing, and in accordance with § 112.7, and any other applicable section of this part.

(a) If your onshore or offshore facility was in operation on or before August 16, 2002, you must maintain your Plan, but must amend it, if necessary to ensure compliance with this part, on or before February 17, 2003, and must implement the amended Plan as soon as possible, but not later than August 18, 2003. If your onshore or offshore facility becomes operational after August 16, 2002, through August 18, 2003, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare a Plan on or before August 18, 2003, and fully implement it as soon as possible, but not later than August 18, 2003.

(b) If you are the owner or operator of an onshore or offshore facility that becomes operational after August 18, 2003, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan before you begin operations.

(c) If you are the owner or operator of an onshore or offshore mobile facility, such as an onshore drilling or workover rig, barge mounted offshore drilling or workover rig, or portable fueling facility, you must prepare, implement, and maintain a facility Plan as required by this section. This provision does not require that you prepare a new Plan each time you move the facility to a new site. The Plan may be a general plan. When you move the mobile or portable facility, you must locate and install it using the discharge prevention practices outlined in the Plan for the facility. You may not operate a mobile or portable facility subject to this part unless you have implemented the Plan. The Plan is applicable only while the facility is in a fixed (non-transportation) operating mode.

(d) A licensed Professional Engineer must review and certify a Plan for it to be effective to satisfy the requirements of this part.

(1) By means of this certification the Professional Engineer attests:

(i) That he is familiar with the requirements of this part ;

(ii) That he or his agent has visited and examined the facility;

(iii) That the Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part;

(iv) That procedures for required inspections and testing have been established; and

(v) That the Plan is adequate for the facility.

(2) Such certification shall in no way relieve the owner or operator of a facility of his duty to prepare and fully implement such Plan in accordance with the requirements of this part.

(e) If you are the owner or operator of a facility for which a Plan is required under this section, you must:

(1) Maintain a complete copy of the Plan at the facility if the facility is normally attended at least four hours per day, or at the nearest field office if the facility is not so attended, and

(2) Have the Plan available to the Regional Administrator for on-site review during normal working hours.

(f) *Extension of time.* (1) The Regional Administrator may authorize an extension of time for the preparation and full implementation of a Plan, or any amendment thereto, beyond the time permitted for the preparation, implementation, or amendment of a

Plan under this part, when he finds that the owner or operator of a facility subject to this section, cannot fully comply with the requirements as a result of either nonavailability of qualified personnel, or delays in construction or equipment delivery beyond the control and without the fault of such owner or operator or his agents or employees.

(2) If you are an owner or operator seeking an extension of time under paragraph (f)(1) of this section, you may submit a written extension request to the Regional Administrator. Your request must include:

(i) A full explanation of the cause for any such delay and the specific aspects of the Plan affected by the delay;

(ii) A full discussion of actions being taken or contemplated to minimize or mitigate such delay; and

(iii) A proposed time schedule for the implementation of any corrective actions being taken or contemplated, including interim dates for completion of tests or studies, installation and operation of any necessary equipment, or other preventive measures. In addition you may present additional oral or written statements in support of your extension request.

(3) The submission of a written extension request under paragraph (f)(2) of this section does not relieve you of your obligation to comply with the requirements of this part. The Regional Administrator may request a copy of your Plan to evaluate the extension request. When the Regional Administrator authorizes an extension of time for particular equipment or other specific aspects of the Plan, such extension does not affect your obligation to comply with the requirements related to other equipment or other specific aspects of the Plan for which the Regional Administrator has not expressly authorized an extension.

§ 112.4 Amendment of Spill Prevention, Control, and Countermeasure Plan by Regional Administrator.

If you are the owner or operator of a facility subject to this part, you must:

(a) Notwithstanding compliance with § 112.3, whenever your facility has discharged more than 1,000 U.S. gallons of oil in a single discharge as described in § 112.1(b), or discharged more than 42 U.S. gallons of oil in each of two discharges as described in § 112.1(b), occurring within any twelve month period, submit the following information to the Regional Administrator within 60 days from the time the facility becomes subject to this section:

(1) Name of the facility;

(2) Your name;

(3) Location of the facility;

(4) Maximum storage or handling capacity of the facility and normal daily throughput;

(5) Corrective action and countermeasures you have taken, including a description of equipment repairs and replacements;

(6) An adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary;

(7) The cause of such discharge as described in § 112.1(b), including a failure analysis of the system or subsystem in which the failure occurred;

(8) Additional preventive measures you have taken or contemplated to minimize the possibility of recurrence; and

(9) Such other information as the Regional Administrator may reasonably require pertinent to the Plan or discharge.

(b) Take no action under this section until it applies to your facility. This section does not apply until the expiration of the time permitted for the initial preparation and implementation of the Plan under § 112.3, but not including any amendments to the Plan.

(c) Send to the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located a complete copy of all information you provided to the Regional Administrator under paragraph (a) of this section. Upon receipt of the information such State agency or agencies may conduct a review and make recommendations to the Regional Administrator as to further procedures, methods, equipment, and other requirements necessary to prevent and to contain discharges from your facility.

(d) Amend your Plan, if after review by the Regional Administrator of the information you submit under paragraph (a) of this section, or submission of information to EPA by the State agency under paragraph (c) of this section, or after on-site review of your Plan, the Regional Administrator requires that you do so. The Regional Administrator may require you to amend your Plan if he finds that it does not meet the requirements of this part or that amendment is necessary to prevent and contain discharges from your facility.

(e) Act in accordance with this paragraph when the Regional Administrator proposes by certified mail or by personal delivery that you amend your SPCC Plan. If the owner or operator is a corporation, he must also notify by mail the registered agent of such corporation, if any and if known, in the State in which the facility is located. The Regional Administrator must specify the terms of such proposed amendment. Within 30 days from receipt of such notice, you may submit written information, views, and arguments on the proposed amendment. After considering all relevant material presented, the Regional Administrator must either notify you of any amendment required or rescind the notice. You must amend your Plan as required within 30 days after such notice, unless the Regional Administrator, for good cause, specifies another effective date. You must implement the amended Plan as soon as possible, but not later than six months after you amend your Plan, unless the Regional Administrator specifies another date.

(f) If you appeal a decision made by the Regional Administrator requiring an amendment to an SPCC Plan, send the appeal to the EPA Administrator in writing within 30 days of receipt of the notice from the Regional Administrator requiring the amendment under paragraph (e) of this section. You must send a complete copy of the appeal to the Regional Administrator at the time you make the appeal. The appeal must contain a clear and concise statement of the issues and points of fact in the case. It may also contain additional information from you, or from any other person. The EPA Administrator may request additional information from you, or from any other person. The EPA Administrator must render a decision within 60 days of receiving the appeal and must notify you of his decision.

§ 112.5 Amendment of Spill Prevention, Control, and Countermeasure Plan by owners or operators.

If you are the owner or operator of a facility subject to this part, you must:

(a) Amend the SPCC Plan for your facility in accordance with the general requirements in § 112.7, and with any specific section of this part applicable to your facility, when there is a change in the facility design, construction, operation, or maintenance that materially affects its potential for a discharge as described in § 112.1(b). Examples of changes that may require amendment of the Plan include, but are not limited to: commissioning or decommissioning containers; replacement, reconstruction, or movement of containers; reconstruction, replacement, or installation of piping systems; construction or demolition that might alter secondary containment structures; changes of product or service; or revision of standard operation or maintenance procedures at a facility. An amendment made under this section must be prepared within six months, and implemented as soon as possible, but not later than six months following preparation of the amendment.

(b) Notwithstanding compliance with paragraph (a) of this section, complete a review and evaluation of the SPCC Plan at least once every five years from the date your facility becomes subject to this part; or, if your facility was in operation on or before August 16, 2002, five years from the date your last review was required under this part. As a result of this review and evaluation, you must amend your SPCC Plan within six months of the review to include more effective prevention and control technology if the technology has been field-proven at the time of the review and will significantly reduce the likelihood of a discharge as described in § 112.1(b) from the facility. You must implement any amendment as soon as possible, but not later than six months following preparation of any amendment. You must document your completion of the review and evaluation, and must sign a statement as to whether you will amend the Plan, either at the beginning or end of the Plan or in a log or an appendix to the Plan. The following words will suffice, "I have completed review and evaluation of the SPCC Plan for (name of facility) on (date), and will (will not) amend the Plan as a result."

(c) Have a Professional Engineer certify any technical amendment to your Plan in accordance with § 112.3(d).

§ 112.6 [Reserved]

§ 112.7 General requirements for Spill Prevention, Control, and Countermeasure Plans.

If you are the owner or operator of a facility subject to this part you must prepare a Plan in accordance with good engineering practices. The Plan must have the full approval of management at a level of authority to commit the necessary resources to fully implement the Plan. You must prepare the Plan in writing. If you do not follow the sequence specified in this section for the Plan, you must prepare an equivalent Plan acceptable to the Regional Administrator that meets all of the applicable requirements listed in this part, and you must supplement it with a section cross-referencing the location of requirements listed in this part and the equivalent requirements in the other prevention plan. If the Plan calls for additional facilities or procedures, methods, or equipment not yet fully operational, you must discuss these items in separate paragraphs, and must explain separately the details of installation and operational start-up. As detailed elsewhere in this section, you must also:

(a)(1) Include a discussion of your facility's conformance with the requirements listed in this part.

(2) Comply with all applicable requirements listed in this part. Your Plan may deviate from the requirements in paragraphs (g), (h)(2) and (3), and (i) of this section and the requirements in subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§ 112.8(c)(2),112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), 112.12(c)(11),112.13(c)(2), and 112.14(c), where applicable to a specific facility, if you provide equivalent environmental protection by some other means of spill prevention, control, or countermeasure. Where your Plan does not conform to the applicable requirements in paragraphs (g), (h)(2) and (3), and (i) of this section, or the requirements of subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§ 112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), 112.12(c)(11), 112.13(c)(2), and 112.14(c), you must state the reasons for nonconformance in your Plan and describe in detail alternate methods and how you will achieve equivalent environmental protection. If the Regional Administrator determines that the measures described in your Plan do not provide equivalent environmental protection, he may require that you amend your Plan, following the procedures in § 112.4(d) and (e).

(3) Describe in your Plan the physical layout of the facility and include a facility diagram, which must mark the location and contents of each container. The facility diagram must include completely buried tanks that are otherwise exempted from the requirements of this part under § 112.1(d)(4). The facility diagram must also include all transfer stations and connecting pipes. You must also address in your Plan:

(i) The type of oil in each container and its storage capacity;

(ii) Discharge prevention measures including procedures for routine handling of products (loading, unloading, and facility transfers, *etc.*);

(iii) Discharge or drainage controls such as secondary containment around containers and other structures, equipment, and procedures for the control of a discharge;

(iv) Countermeasures for discharge discovery, response, and cleanup (both the facility's capability and those that might be required of a contractor);

(v) Methods of disposal of recovered materials in accordance with applicable legal requirements; and

(vi) Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with whom you have an agreement for response, and all appropriate Federal, State, and local agencies who must be contacted in case of a discharge as described in § 112.1(b).

(4) Unless you have submitted a response plan under § 112.20, provide information and procedures in your Plan to enable a person reporting a discharge as described in § 112.1(b) to relate information on the exact address or location and phone number of the facility; the date and time of the discharge, the type of material discharged; estimates of the total quantity discharged; estimates of the quantity discharged as described in § 112.1(b); the source of the discharge; a description of all affected media; the cause of the discharge; any damages or injuries caused by the discharge; actions being used to stop, remove, and mitigate the effects of the discharge; whether an evacuation may be needed; and, the names of individuals and/or organizations who have also been contacted.

(5) Unless you have submitted a response plan under § 112.20, organize portions of the Plan describing procedures you will use when a discharge occurs in a way that will make them readily usable in an emergency, and include appropriate supporting material as appendices.

(b) Where experience indicates a reasonable potential for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of a discharge), include in your Plan a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure.

(c) Provide appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in § 112.1(b). The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank or pipe, will not escape the containment system before cleanup occurs. At a minimum, you must use one of the following prevention systems or its equivalent:

(1) For onshore facilities:
(i) Dikes, berms, or retaining walls sufficiently impervious to contain oil;
(ii) Curbing;
(iii) Culverting, gutters, or other drainage systems;
(iv) Weirs, booms, or other barriers;
(v) Spill diversion ponds;
(vi) Retention ponds; or
(vii) Sorbent materials.
(2) For offshore facilities:
(i) Curbing or drip pans; or
(ii) Sumps and collection systems.

(d) If you determine that the installation of any of the structures or pieces of equipment listed in paragraphs (c) and (h)(1) of this section, and §§ 112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), 112.12(c)(11), 112.13(c)(2), and 112.14(c) to prevent a discharge as described in § 112.1(b) from any onshore or offshore facility is not practicable, you must clearly explain in your Plan why such measures are not practicable; for bulk storage containers, conduct both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; and, unless you have submitted a response plan under § 112.20, provide in your Plan the following:

(1) An oil spill contingency plan following the provisions of part 109 of this chapter.

(2) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

(e) *Inspections, tests, and records.* Conduct inspections and tests required by this part in accordance with written procedures that you or the certifying engineer develop for the facility. You must keep these written procedures and a record of the inspections and tests, signed by the appropriate supervisor or inspector, with the SPCC Plan for a period of three years. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

(f) *Personnel, training, and discharge prevention procedures.* (1) At a minimum, train your oil-handling personnel in the operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and, the contents of the facility SPCC Plan.

(2) Designate a person at each applicable facility who is accountable for discharge prevention and who reports to facility management.

(3) Schedule and conduct discharge prevention briefings for your oil-handling personnel at least once a year to assure adequate understanding of the SPCC Plan for that facility. Such briefings must highlight and describe known discharges as described in § 112.1(b) or failures, malfunctioning components, and any recently developed precautionary measures.

(g) *Security (excluding oil production facilities).* (1) Fully fence each facility handling, processing, or storing oil, and lock and/or guard entrance gates when the facility is not in production or is unattended.

(2) Ensure that the master flow and drain valves and any other valves permitting direct outward flow of the container's contents to the surface have adequate security measures so that they remain in the closed position when in non-operating or non-standby status.

(3) Lock the starter control on each oil pump in the "off" position and locate it at a site accessible only to authorized personnel when the pump is in a non-operating or non-standby status.

(4) Securely cap or blank-flange the loading/unloading connections of oil pipelines or facility piping when not in service or when in standby service for an extended time. This security practice also applies to piping that is emptied of liquid content either by draining or by inert gas pressure.

(5) Provide facility lighting commensurate with the type and location of the facility that will assist in the:
(i) Discovery of discharges occurring during hours of darkness, both by operating personnel, if present, and by non-operating personnel (the general public, local police, etc.); and
(ii) Prevention of discharges occurring through acts of vandalism.

(h) *Facility tank car and tank truck loading/unloading rack (excluding offshore facilities).* (1) Where loading/unloading area drainage does not flow into a catchment basin or treatment facility designed to handle discharges, use a quick drainage system for tank car or tank truck loading and unloading areas. You must design any containment system to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility.

(2) Provide an interlocked warning light or physical barrier system, warning signs, wheel chocks, or vehicle break interlock system in loading/unloading areas to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines.

(3) Prior to filling and departure of any tank car or tank truck, closely inspect for discharges the lowermost drain and all outlets of such vehicles, and if necessary, ensure that they are tightened, adjusted, or replaced to prevent liquid discharge while in transit.

(i) If a field-constructed aboveground container undergoes a repair, alteration, reconstruction, or a change in service that might affect the risk of a discharge or failure due to brittle fracture or other catastrophe, or has discharged oil or failed due to brittle fracture failure or other catastrophe, evaluate the container for risk of discharge or failure due to brittle fracture or other catastrophe, and as necessary, take appropriate action.

(j) In addition to the minimal prevention standards listed under this section, include in your Plan a complete discussion of conformance with the applicable requirements and other effective discharge prevention and containment procedures listed in this part or any applicable more stringent State rules, regulations, and guidelines.

3. Part 112 is amended adding subpart B consisting of §§ 112.8 through 112.11 to read as follows:

Subpart B—Requirements for Petroleum Oils and Non-Petroleum Oils, Except Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and Vegetable Oils (Including Oils from Seeds, Nuts, Fruits, and Kernels)

Subpart B—Requirements for Petroleum Oils and Non-Petroleum Oils, Except Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and Vegetable Oils (Including Oils from Seeds, Nuts, Fruits, and Kernels)

§ 112.8 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).

If you are the owner or operator of an onshore facility (excluding a production facility), you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed in this section.

(b) *Facility drainage.* (1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, as provided in paragraphs (c)(3)(ii), (iii), and (iv) of this section.

(3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.

(4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.

(5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two "lift" pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in § 112.1(b) in case there is an equipment failure or human error at the facility.

(c) *Bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.

(2) Construct all bulk storage container installations so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

(3) Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in § 112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§ 122.41(j)(2) and 122.41(m)(3) of this chapter.

(4) Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

(5) Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.

(6) Test each aboveground container for integrity on a regular schedule, and whenever you make material repairs. The frequency of and type of testing must take into account container size and design (such as floating roof, skid-mounted, elevated, or partially buried). You must combine visual inspection with another testing technique such as hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or another system of non-destructive shell testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

(7) Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.

(8) Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

(9) Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in § 112.1(b).

(10) Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

(11) Position or locate mobile or portable oil storage containers to prevent a discharge as described in § 112.1(b). You must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

(d) *Facility transfer operations, pumping, and facility process.* (1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.

(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.

(3) Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

§ 112.9 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil production facilities.

If you are the owner or operator of an onshore production facility, you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed under this section.

(b) *Oil production facility drainage.* (1) At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in § 112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under § 112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in § 112.8(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

(c) *Oil production facility bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage.

(2) Provide all tank battery, separation, and treating facility installations with a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely confine drainage from undiked areas in a catchment basin or holding pond.

(3) Periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground.

(4) Engineer or update new and old tank battery installations in accordance with good engineering practice to prevent discharges. You must provide at least one of the following:

(i) Container capacity adequate to assure that a container will not overfill if a pumper/gauger is delayed in making regularly scheduled rounds.

(ii) Overflow equalizing lines between containers so that a full container can overflow to an adjacent container.

(iii) Vacuum protection adequate to prevent container collapse during a pipeline run or other transfer of oil from the container.

(iv) High level sensors to generate and transmit an alarm signal to the computer where the facility is subject to a computer production control system.

(d) *Facility transfer operations, oil production facility.* (1) Periodically and upon a regular schedule inspect all aboveground valves and piping associated with transfer operations for the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items.

(2) Inspect saltwater (oil field brine) disposal facilities often, particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge.

(3) Have a program of flowline maintenance to prevent discharges from each flowline.

§ 112.10 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.

If you are the owner or operator of an onshore oil drilling and workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Position or locate mobile drilling or workover equipment so as to prevent a discharge as described in § 112.1(b).

(c) Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.

(d) Install a blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

§ 112.11 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

If you are the owner or operator of an offshore oil drilling, production, or workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Use oil drainage collection equipment to prevent and control small oil discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment. You must control and direct facility drains toward a central collection sump to prevent the facility from having a discharge as described in § 112.1(b). Where drains and sumps are not practicable, you must remove oil contained in collection equipment as often as necessary to prevent overflow.

(c) For facilities employing a sump system, provide adequately sized sump and drains and make available a spare pump to remove liquid from the sump and assure that oil does not escape. You must employ a regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(d) At facilities with areas where separators and treaters are equipped with dump valves which predominantly fail in the closed position and where pollution risk is high, specially equip the facility to prevent the discharge of oil. You must prevent the discharge of oil by:

(1) Extending the flare line to a diked area if the separator is near shore;

(2) Equipping the separator with a high liquid level sensor that will automatically shut in wells producing to the separator; or

(3) Installing parallel redundant dump valves.

(e) Equip atmospheric storage or surge containers with high liquid level sensing devices that activate an alarm or control the flow, or otherwise prevent discharges.

(f) Equip pressure containers with high and low pressure sensing devices that activate an alarm or control the flow.

(g) Equip containers with suitable corrosion protection.

(h) Prepare and maintain at the facility a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems.

(i) Conduct testing and inspection of the pollution prevention equipment and systems at the facility on a scheduled periodic basis, commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations. You must use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems.

(j) Describe in detailed records surface and subsurface well shut-in valves and devices in use at the facility for each well sufficiently to determine their method of activation or control, such as pressure differential, change in fluid or flow conditions, combination of pressure and flow, manual or remote control mechanisms.

(k) Install a BOP assembly and well control system during workover operations and before drilling below any casing string. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while the BOP assembly and well control system are on the well.

(l) Equip all manifolds (headers) with check valves on individual flowlines.

(m) Equip the flowline with a high pressure sensing device and shut-in valve at the wellhead if the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to and including the header valves. Alternatively you may provide a pressure relief system for flowlines.

(n) Protect all piping appurtenant to the facility from corrosion, such as with protective coatings or cathodic protection.

(o) Adequately protect sub-marine piping appurtenant to the facility against environmental stresses and other activities such as fishing operations.

(p) Maintain sub-marine piping appurtenant to the facility in good operating condition at all times. You must periodically and according to a schedule inspect or test such piping for failures. You must document and keep a record of such inspections or tests at the facility.

4. Part 112 is amended by adding subpart C consisting of §§ 112.12 through 112.15 to read as follows:

Subpart C—Requirements for Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and for Vegetable Oils, Including Oils from Seeds, Nuts, Fruits and Kernels

Subpart C—Requirements for Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and for Vegetable Oils, Including Oils from Seeds, Nuts, Fruits, and Kernels.

§ 112.12 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities)

If you are the owner or operator of an onshore facility (excluding a production facility), you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed in this section.

(b) *Facility drainage.* (1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, subject to the requirements of paragraphs (c)(3)(ii), (iii), and (iv) of this section.

(3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.

(4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.

(5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two "lift" pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in § 112.1(b) in case there is an equipment failure or human error at the facility.

(c) *Bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.

(2) Construct all bulk storage container installations so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

(3) Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in § 112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§ 122.41(j)(2) and 122.41(m)(3) of this chapter.

(4) Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by

coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

(5) Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.

(6) Test each aboveground container for integrity on a regular schedule, and whenever you make material repairs. The frequency of and type of testing must take into account container size and design (such as floating roof, skid-mounted, elevated, or partially buried). You must combine visual inspection with another testing technique such as hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or another system of non-destructive shell testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

(7) Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.

(8) Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

(9) Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in § 112.1(b).

(10) Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

(11) Position or locate mobile or portable oil storage containers to prevent a discharge as described in § 112.1(b). You must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

(d) *Facility transfer operations, pumping, and facility process.* (1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.

(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.

(3) Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

§ 112.13 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil production facilities.

If you are the owner or operator of an onshore production facility, you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed under this section.

(b) *Oil production facility drainage.* (1) At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in § 112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under § 112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in § 112.12(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

(c) *Oil production facility bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage.

(2) Provide all tank battery, separation, and treating facility installations with a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely confine drainage from undiked areas in a catchment basin or holding pond.

(3) Periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground.

(4) Engineer or update new and old tank battery installations in accordance with good engineering practice to prevent discharges. You must provide at least one of the following:

(i) Container capacity adequate to assure that a container will not overfill if a pumper/gauger is delayed in making regularly scheduled rounds.

(ii) Overflow equalizing lines between containers so that a full container can overflow to an adjacent container.

(iii) Vacuum protection adequate to prevent container collapse during a pipeline run or other transfer of oil from the container.

(iv) High level sensors to generate and transmit an alarm signal to the computer where the facility is subject to a computer production control system.

(d) *Facility transfer operations, oil production facility.* (1) Periodically and upon a regular schedule inspect all aboveground valves and piping associated with transfer operations for the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items.

(2) Inspect saltwater (oil field brine) disposal facilities often, particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge.

(3) Have a program of flowline maintenance to prevent discharges from each flowline.

§ 112.14 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.

If you are the owner or operator of an onshore oil drilling and workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Position or locate mobile drilling or workover equipment so as to prevent a discharge as described in § 112.1(b).

(c) Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.

(d) Install a blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

§ 112.15 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

If you are the owner or operator of an offshore oil drilling, production, or workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Use oil drainage collection equipment to prevent and control small oil discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment. You must control and direct facility drains toward a central collection sump to prevent the facility from having a discharge as described in § 112.1(b). Where drains and sumps are not practicable, you must remove oil contained in collection equipment as often as necessary to prevent overflow.

(c) For facilities employing a sump system, provide adequately sized sump and drains and make available a spare pump to remove liquid from the sump and assure that oil does not escape. You must employ a regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(d) At facilities with areas where separators and treaters are equipped with dump valves which predominantly fail in the closed position and where pollution risk is high, specially equip the facility to prevent the discharge of oil. You must prevent the discharge of oil by:

(1) Extending the flare line to a diked area if the separator is near shore;

(2) Equipping the separator with a high liquid level sensor that will automatically shut in wells producing to the separator; or

(3) Installing parallel redundant dump valves.

(e) Equip atmospheric storage or surge containers with high liquid level sensing devices that activate an alarm or control the flow, or otherwise prevent discharges.

(f) Equip pressure containers with high and low pressure sensing devices that activate an alarm or control the flow.

(g) Equip containers with suitable corrosion protection.

(h) Prepare and maintain at the facility a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems.

(i) Conduct testing and inspection of the pollution prevention equipment and systems at the facility on a scheduled periodic basis, commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations. You must use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems.

(j) Describe in detailed records surface and subsurface well shut-in valves and devices in use at the facility for each well sufficiently to determine their method of activation or control, such as pressure differential, change in fluid or flow conditions, combination of pressure and flow, manual or remote control mechanisms.

(k) Install a BOP assembly and well control system during workover operations and before drilling below any casing string. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

(l) Equip all manifolds (headers) with check valves on individual flowlines.

(m) Equip the flowline with a high pressure sensing device and shut-in valve at the wellhead if the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to and including the header valves. Alternatively you may provide a pressure relief system for flowlines.

(n) Protect all piping appurtenant to the facility from corrosion, such as with protective coatings or cathodic protection.

(o) Adequately protect sub-marine piping appurtenant to the facility against environmental stresses and other activities such as fishing operations.

(p) Maintain sub-marine piping appurtenant to the facility in good operating condition at all times. You must periodically and according to a schedule inspect or test such piping for failures. You must document and keep a record of such inspections or tests at the facility.

5. Part 112 is amended by designating §§ 112.20 and 112.21 as subpart D, and adding a subpart heading as follows:

Subpart D—Response Requirements

Sec.
112.20 Facility response plans.
112.21 Facility response training and drills/exercises.

Subpart D—Response Requirements

6. Section 112.20 is amended by revising the first sentence of paragraph (h) to read as follows:

§ 112.20 Facility response plans.

* * * * *

(h) A response plan shall follow the format of the model facility-specific response plan included in Appendix F to this part, unless you have prepared an equivalent response plan acceptable to the Regional Administrator to meet State or other Federal requirements. * * *

* * * * *

Appendix C—[Amended]

7. Appendix C of part 112 is amended by:

a. Revising the first sentence of section 2.1; and

b. Revising the title and first sentence of section 2.4.

Appendix C to Part 112—Substantial Harm Criteria

* * * * *

2.1 Non-Transportation-Related Facilities With a Total Oil Storage Capacity Greater Than or Equal to 42,000 Gallons Where Operations Include Over-Water Transfers of Oil

A non-transportation-related facility with a total oil storage capacity greater than or equal to 42,000 gallons that transfers oil over water to or from vessels must submit a response plan to EPA. * * *

* * * * *

2.4 Proximity to Public Drinking Water Intakes at Facilities with a Total Oil Storage Capacity Greater than or Equal to 1 Million Gallons

A facility with a total oil storage capacity greater than or equal to 1 million gallons must submit its response plan if it is located at a distance such that a discharge from the facility would shut down a public drinking water intake, which is analogous to a public water system as described at 40 CFR 143.2(c). * * *

* * * * *

Appendix D—[Amended]

8. Appendix D of part 112 is amended by revising footnote 2 to section A.2 of Part A to read as follows:

Appendix D to Part 112—Determination of a Worst Case Discharge Planning Volume

* * * * *

Part A * * *

* * * * *

A.2 Secondary Containment—Multiple-Tank Facilities

* * * * *

Secondary containment is described in 40 CFR part 112, subparts A through C. Acceptable methods and structures for containment are also given in 40 CFR 112.7(c)(1).

* * * * *

Appendix F—[Amended]

9. Appendix F of part 112 is amended by:

a. Revising section 1.2.7;

b. Revising the second and last sentences of section 1.4.3;

c. Revising paragraph (7) and the undesignated paragraph and NOTE following paragraph (7) in section 1.7.3;

d. Revising section 1.8.1;

e. Revising the first two sentences of section 1.8.1.1. introductory text;

f. Revising the next to the last sentence of section 1.8.1.3;

g. Revising the next to last sentence of section 1.10.;

h. Revising paragraph (6) of section 2.1;

i. Remove the acronym "SIC" in section 3.0, and add in alphabetical order the acronym "NAICS'; and.

j. Remove the reference to "Standard Industrial Classification (SIC) Code" in Attachment F–1, General Information, and add in in alphabetical order a reference to "North American Industrial Classification System (NAICS) Code."

The revisions read as follows:

Appendix F to Part 112—Facility-Specific Response Plan

* * * * *

1.2.7 Current Operation

Briefly describe the facility's operations and include the North American Industrial Classification System (NAICS) code.

* * * * *

1.4.3 Analysis of the Potential for an Oil Discharge

* * * This analysis shall incorporate factors such as oil discharge history, horizontal range of a potential discharge, and vulnerability to natural disaster, and shall, as appropriate, incorporate other factors such as tank age. * * * The owner or operator may need to research the age of the tanks the oil discharge history at the facility.

* * * * *

1.7.3 Containment and Drainage Planning

* * * * *

(7) Other cleanup materials.

In addition, a facility owner or operator must meet the inspection and monitoring requirements for drainage contained in 40 CFR part 112, subparts A through C. A copy of the containment and drainage plans that are required in 40 CFR part 112, subparts A through C may be inserted in this section, including any diagrams in those plans.

Note: The general permit for stormwater drainage may contain additional requirements.

* * * * *

1.8.1 Facility Self-Inspection

Under 40 CFR 112.7(e), you must include the written procedures and records of inspections for each facility in the SPCC Plan. You must include the inspection records for each container, secondary containment, and item of response equipment at the facility. You must cross-reference the records of inspections of each container and secondary containment required by 40 CFR 112.7(e) in the facility response plan. The inspection record of response equipment is a new requirement in this plan. Facility self-inspection requires two-steps: (1) a checklist of things to inspect; and (2) a method of recording the actual inspection and its findings. You must note the date of each inspection. You must keep facility response plan records for five years. You must keep SPCC records for three years.

* * * * *

1.8.1.1. Tank Inspection

The tank inspection checklist presented below has been included as guidance during inspections and monitoring. Similar requirements exist in 40 CFR part 112, subparts A through C. * * *

* * * * *

1.8.1.3 Secondary Containment Inspection

* * * * *

* * * Similar requirements exist in 40 CFR part 112, subparts A through C. * * *

* * * * *

1.10 Security

According to 40 CFR 112.7(g) facilities are required to maintain a certain level of security, as appropriate. * * *

* * * * *

2.1 General Information

* * * * *

(6) North American Industrial Classification System (NAICS) Code: Enter the facility's NAICS code as determined by the Office of Management and Budget (this information may be obtained from public library resources.)

* * * * *

3.0 Acronyms

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NAICS: North American Industrial Classification System

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Attachments to Appendix F

Attachment F–1—Response Plan Cover Sheet

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General Information

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North American Industrial Classification System (NAICS) Code:

* * * * *

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