BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 960001-EI
FLORIDA POWER & LIGHT COMPANY

JUNE 24, 1996

IN RE: LEVELIZED FUEL COST RECOVERY
OCTOBER 1996 THROUGH MARCH 1997
AND
CAPACITY COST RECOVERY
OCTOBER 1996 THROUGH SEPTEMBER 1997

TESTIMONY & EXHIBITS OF:

R. SILVA
C. VILLARD
B. T. BIRKETT
R. L. WADE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENE SILVA

DOCKET NO. 960001-EI

June 24, 1996

Q **Please state your name and address.**

A. My name is Rene Silva. My business address is 9250 W. Flagler Street, Miami, Florida 33174.

Q. **By whom are you employed and what is your position?**

A. I am employed by Florida Power & Light Company (FPL) as Manager of Forecasting and Regulatory Response in the Power Generation Business Unit.

Q. **Have you previously testified in this docket?**

A. Yes.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to present and explain FPL's projections for (1) dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas, (2) availability of natural gas to FPL, (3) generating unit heat rates and availabilities, and (4) quantities and costs of interchange and other power transactions. These projected values were used as input values to POWRSYM in the calculation of the proposed fuel cost recovery factor for the period October, 1996 through March,1997.

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

A. Yes, I have. It consists of pages 1 through 7 of Appendix I of this filing.

Q. **What are the key factors that could affect FPL's price for heavy fuel oil during the October, 1996 through March, 1997 period?**

A. The key factors are (1) demand for crude oil and petroleum products (including heavy fuel oil), (2) non-OPEC crude oil production, (3) the extent to which OPEC production matches actual demand for OPEC crude oil, (4) the relationship between heavy fuel oil and crude oil, and (5) the terms of FPL's heavy fuel oil supply and transportation contracts.

In general, world demand for crude oil and petroleum products is projected to continue to increase at a moderate rate through 1997 as a result of continued economic growth in the Pacific Rim countries.

On the supply side, total non-OPEC crude oil production is projected to rise slightly through 1997 due to increases in the North Sea and Latin America. The balance of the projected increase in crude oil demand is projected to be adequately met by a slight increase in OPEC production.

Based on these factors crude oil prices, and consequently heavy fuel oil prices, for the October, 1996 to March, 1997 period will be slightly lower than for the October, 1995 to March, 1996 period.

Q. **What is the projected relationship between heavy fuel oil and crude oil prices during the October, 1996 through March, 1997 period?**

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 78% of the price of West Texas Intermediate (WTI) crude oil.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the October, 1996 through March, 1997 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by sulfur grade, by month, is provided on page 3 of Appendix I in dollars per barrel.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors that affect the price of light fuel oil are similar to those described above for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the period from October, 1996 to March, 1997.

A. FPL's projection for the average dispatch cost of light oil, by sulfur grade, by month, is shown on page 4 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal?

A. FPL's projected dispatch cost of coal is based on FPL's price projection of spot coal delivered to its coal plants.

For St. Johns River Power Park (SJRPP), annual coal volumes delivered under long-term contracts are fixed on October 1st of the previous year. For Scherer Plant, the annual volume of coal delivered under long-term contracts is set by the terms of the contracts. Therefore, the price of coal delivered under long-term contracts does not affect the daily dispatch decision. The dispatch price of coal for each coal plant is based on the variable component of the coal cost, the projected spot coal price.

Q. Please provide FPL's projection for the dispatch cost of coal for the October, 1996 through March, 1997 period.

A. FPL's projected system average dispatch cost of coal, shown on page 5 of Appendix I, is about $1.50 per million BTU, delivered to plant.

Q. What are the factors that can affect FPL's natural gas prices during the October, 1996 through March, 1997 period?

A. In general, the key factors are (1) domestic natural gas demand and supply, (2) foreign natural gas imports, (3) heavy fuel oil prices and (4) the terms of FPL's gas supply and transportation contracts. For the projected period, the dominant factor influencing the price of gas will be strong gas demand caused by the current low level of gas inventory.

Every year, between the months of April and October, natural gas market inventories are built up as a reserve in preparation for peak winter gas demand. These inventories are partially drawn down during the winter months as needed. Only a portion of the gas reserve is used during the winter, and the impact on summer demand of restoring inventory to the desired level is usually moderate. However, the quantity of natural gas in inventory at the beginning of the winter of 1995-1996 was lower than in previous years. And colder than normal weather during the winter caused a very large draw on inventory to meet the strong gas demand. As a result, the quantity of gas in inventory in April and May, 1996 - the beginning of the gas "injection" season - was much lower than it has been in the past, and it is projected that gas inventory will not even reach the year-earlier level by the end of the "injection" season in October, 1996.

It is projected that this situation will keep demand for natural gas very strong during the summer and continuing through the winter of 1996-1997. Consequently, gas prices are projected to remain firm through

March, 1997.

Q. **What are the factors that affect the availability of natural gas to FPL during the October, 1996 through March, 1997 period?**

A. The key factors are (1) the existing capacity of natural gas transportation facilities into Florida, (2) the portion of that capacity that is contractually allocated to FPL on a firm, "guaranteed" basis each month and (3) the natural gas demand in the State of Florida.

The current capacity of natural gas transportation facilities into the State of Florida is 1,455,000 million BTU per day (including FPL's firm allocation of 455,000 to 480,000 million BTU per day, depending on the month). Total demand for natural gas in the State during the period (including FPL's firm allocation) is projected to be between 255,000 and 265,000 million BTU per day below the pipeline's total capacity. This projected available pipeline capacity could enable FPL to acquire and deliver additional natural gas, beyond FPL's 455,000 to 480,000 million BTU per day of firm, "guaranteed" allocation, should it be economically attractive, relative to other energy choices.

Q. **Please provide FPL's projections for the dispatch cost and**

availability (to FPL) of natural gas for the October, 1996 through March, 1997 period.

A. FPL's projections of the system average dispatch cost and availability of natural gas are provided on page 6 of Appendix I.

Q. **Please describe how you have developed the projected unit Average Net Operating Heat Rates shown on Schedule E4 of Appendix II.**

A. The projected Average Net Operating Heat Rates were developed using the actual monthly Average Net Operating Heat Rates and the corresponding Net Output Factors from previous October through March periods. This historical data was used to calculate an efficiency factor, or heat rate multiplier, for each generating unit. The most recent unit dispatch heat rate curves, modified by the unit's efficiency factors, were provided as input to the POWRSYM model.

Q. **Are you providing the outage factors projected for the period October, 1996 through March, 1997?**

A. Yes. This data is shown on page 7 of Appendix I.

Q. **How were the outage factors for this period developed?**

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The actual unplanned outage factor of each generating unit for the previous twelve-month period was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the October, 1996 through March, 1997 period.

Q. Please describe significant planned outages for the October, 1996 through March, 1997 period.

A. Planned outages at our nuclear units are the most significant in relation to Fuel Cost Recovery. Turkey Point Unit No.3 is scheduled to be out of service for refueling beginning on March 8, 1997 and until April 21, 1997, or twenty four days during the projected period. There are no other significant planned outages during the projected period.

Q. Are any changes to FPL's generation capacity planned during the October, 1996 through March, 1997 period?

A. No.

Q. Are you providing the projected interchange and purchased power transactions forecasted for October, 1996 through March, 1997?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of interchange transactions does FPL engage?

A. FPL purchases interchange power from others under several types of interchange transactions which have been previously described in this docket: Emergency - Schedule A; Short Term Firm - Schedule B; Economy - Schedule C; Extended Economy - Schedule X; Opportunity Sales - Schedule OS; UPS Replacement Energy - Schedule R and Economic Energy Participation - Schedule EP. For services provided by FPL to other utilities, FPL has developed amended Interchange Service Schedules, including AF (Emergency), BF (Scheduled Maintenance), CF (Economy), DF (Outage), and XF (Extended Economy). These amended schedules replace and supersede existing Interchange Service Schedules A, B, C, D, and X for services provided by FPL.

Q. Does FPL have arrangements other than interchange agreements for the purchase of electric power and energy which are included

in your projections?

A. Yes. FPL purchases coal-by-wire electrical energy under the 1988 Unit Power Sales Agreement (UPS) with the Southern Companies. FPL has contracts to purchase nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). FPL also purchases energy from JEA's portion of the SJRPP Units, as stated above. Additionally, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. **Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the October, 1996 through March, 1997 period.**

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 920 MW from October, 1996 through March, 1997. Based upon the alternate and supplemental energy provisions of UPS, an availability factor of 100% is applied to these capacity entitlements to project energy purchases. The projected UPS energy (unit) cost for this period, used as input to POWRSYM, is based on data provided by the Southern Companies. For the period, FPL projects the purchase of 690,143 MWH of UPS Energy at a cost of $12,885,410. In

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF C. VILLARD

DOCKET NO. 960001-EI

June 24, 1996

Q. **Please state your name and address.**

A. My name is Claude Villard. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. **By whom are you employed and what is your position?**

A. I am employed by Florida Power & Light Company (FPL) as Manager of Nuclear Fuel.

Q. **Have you previously testified in this docket?**

A. Yes, I have.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to present and explain FPL's projections of nuclear fuel costs for the thermal energy (MMBTU) to be produced by our nuclear units and costs of disposal of spent nuclear fuel. Both of these costs were input values to POWRSYM for the calculation of the proposed fuel cost recovery factor for the period October 1996 through March 1997.

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using energy production at our nuclear units and their operating schedules, consistent with those assumed in POWRSYM, for the period October 1996 through March 1997.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period October 1996 through March 1997.

A. We estimate the nuclear units will produce 126,959,392 MBTU of energy at a cost of $0.351 per MMBTU, excluding spent fuel disposal costs for the period October 1996 through March 1997. Projections by nuclear unit and by month are provided on Schedule E-4 of Appendix II.

Q. Please provide FPL's projections for nuclear spent fuel disposal costs for the period October 1996 through March 1997 and what is the basis for FPL's projections.

A. FPL's projections for nuclear spent fuel disposal costs are provided on Schedule E-2 of Appendix II. These projections are based on FPL's contract with the Department of Energy (DOE), which sets the spent fuel disposal fee at 1 mill per net Kwh generated minus transmission and distribution line losses.

Q. Please provide FPL's projection for Decontamination and Decommissioning (D&D) costs to be paid in the period October 1996 through March 1997 and what is the basis for FPL's projection.

A. As indicated in prior testimony, The National Energy Policy Act of 1992 (The Act) requires FPL to make certain payments to a fund established at the U.S. Treasury, to cover the cost of decontamination and decommissioning DOE's enrichment facilities D&D payments are in direct proportion to the amount of enrichment services purchased by FPL, divided by the amount produced by the DOE, through October 1992, multiplied by the total annual assessment of $480M, as specified in the Energy Policy Act of 1992, and escalated for inflation using the CPI-U (consumer price index - for urban customers). FPL's projection of $5.26M for D&D costs to be paid during the period October 1996 through March 1997 is included on Schedule E-2 of Appendix II.

Q. Are there any other fuel-related costs which FPL is including in the calculation of the proposed Fuel Cost Recovery Factor?

A. Yes. FPL is requesting approval to recover approximately $10 million in costs relating to increasing the thermal power of FPL's Turkey Point Nuclear Units 3 and 4 (hereafter referred to as thermal power uprate). The thermal power uprate of each nuclear unit, from 2200 megawatts thermal to 2300 megawatts thermal, will increase the output of each unit by about 31 megawatts electric.

Q. What benefits will FPL's customers receive from the thermal power uprate of the nuclear units at Turkey Point?

A. FPL projects an approximate 6.1M megawatt hours of additional generation from the Turkey Point nuclear units, assuming that the units would increase power in January, 1997. This higher nuclear generation will result in an estimated fuel savings of about $198 million, representing a present value of approximately $97 million (or $88 million after deducting implementation costs) through the year 2011. These savings are due to the difference between low cost nuclear fuel replacing higher cost fossil fuel. The estimated fuel savings were calculated using the production costing model, POWRSYM. Two POWRSYM cases, with and without the effects of the thermal power uprate, were compared. The Turkey Point assumptions were adjusted to include an increase in output of 31 megawatts, as well as slight adjustments for winter and summer heat rates and equivalent availability factors. The net present value fuel savings were derived by using a rate of 9.2%, which represents FPL's long term decision making discount rate. Document No. 1 shows the breakdown of cost recovery and projected yearly fuel savings.

Q. What activities and costs are involved in the thermal power uprate of the nuclear units at Turkey Point?

A. The thermal uprate requires FPL to formally request the Nuclear Regulatory Commission to amend the operating license for Turkey Point. To receive such license amendment, FPL is required to perform analyses on all affected plant systems, structures and components to ensure there are no adverse impacts on plant safety and operations resulting from the higher power level. Furthermore, the thermal power uprate will also require minor plant modifications.

We are seeking recovery of $7.5M in payments to outside contractors for engineering, safety and licensing efforts, and $2.5M for materials and plant modifications, for a total of $10M. These costs exclude FPL payroll costs and payroll expenses which total approximately $2.3M. We expect the thermal power uprate of each unit will be approved and in-service by year end, 1996. FPL is asking for recovery of these costs starting January 1, 1997.

Q. Please explain why this cost should be approved under the Fuel Cost Recovery Clause?

A. Commission Order No. 14546 provides the basis for recovery of fuel related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers.

This commission order and the significant fuel cost savings to our customers, form the basis for requesting recovery of these costs related to the thermal power uprate of FPL's Turkey Point Units 3 and 4 through the Fuel Cost Recovery Clause. The cost recovery treatment of the Turkey Point thermal power uprate is discussed in the testimony of FPL Witness B. T. Birkett.

Q. **Are there currently any unresolved disputes under FPL's nuclear fuel contracts?**

A. Yes. As reported in prior testimonies, there are two unresolved disputes.

The first dispute is under FPL's contract with the Department of Energy (DOE) for final disposal of spent nuclear fuel. FPL, along with a number of electric utilities, has filed suit against the DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. On December 14, 1995, DOE and the electric utilities began mediation, however no agreement could be reached. Oral arguments took place on January 17, 1996, before the U.S. Court of Appeals for the District of Columbia.

Secondly, FPL is currently seeking to resolve a price dispute for uranium enrichment services purchased from the United States (U.S.) Government, prior to July 1, 1993.

Our contract for enrichment services with the U.S. Government calls for pricing to be calculated in accordance with "Established DOE Pricing Policy". Such policy had always been one of cost recovery, which included costs related to the Decontamination and Decommissioning (D&D) of the DOE's enrichment facilities. However, the Energy Policy Act of 1992 (The Act) requires utilities to make separate payments to the U.S. Treasury for D&D, starting in Fiscal 1993, as FPL has been doing. Therefore, D&D should not have been included in the price charged by DOE for deliveries during Fiscal 1993, and the price should have been reduced accordingly. FPL had filed a claim with the Contracting Officer, on July 14, 1995, for a refund for such deliveries. On October 13, 1995, the DOE Contracting Officer officially rejected FPL's claim. FPL has until October 13, 1996 to file an appeal.

Meanwhile, in a related case, the U.S. Court of Federal Claims ruled that the D&D special assessment itself was unlawful. The Court found that in this specific instance, the special assessment was essentially a retroactive price increase on a contract which had already been performed, and was therefore illegal. The DOE has appealed this decision to the U.S. Court of Appeals for the Federal Circuit and the parties are currently filing their final briefs. Both sides will then await oral arguments, which are scheduled in the Fall. Because the U.S. Court of Federal Claims ruling relied in large part on a case currently being reviewed by the U.S. Supreme Court, the Winstar case, FPL is awaiting the Supreme Court decision, prior to proceeding with the appeal of its case.

Q. Does this conclude your testimony?

A. Yes, it does.

CV-1

DOCKET NO. 960001-EI

FPL WITNESS: CLAUDE VILLARD

EXHIBT NO.________

JUNE 24, 1996

DOCUMENT NO.1
Thermal Uprate NPV Analysis

Year	Project Cost Recovery	Fuel Savings	Net Savings	NPV
96				
97	$5,000,000	$8,560,000	$3,560,000	$3,260,073
98	$5,000,000	$10,150,000	$5,150,000	$4,318,789
99		$10,510,000	$10,510,000	$8,071,139
00		$10,320,000	$10,320,000	$7,257,535
01		$11,600,000	$11,600,000	$7,470,416
02		$12,320,000	$12,320,000	$7,265,657
03		$12,240,000	$12,240,000	$6,610,327
04		$12,660,000	$12,660,000	$6,261,128
05		$14,130,000	$14,130,000	$6,399,388
06		$13,310,000	$13,310,000	$5,520,160
07		$15,160,000	$15,160,000	$5,757,715
08		$15,670,000	$15,670,000	$5,450,010
09		$16,080,000	$16,080,000	$5,121,436
010		$17,030,000	$17,030,000	$4,967,041
011		$18,580,000	$18,580,000	$4,962,564
	$10,000,000	$198,320,000	$188,320,000	$88,693,378

A discount rate of 9.2% was used to determine net present value.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF BARRY T. BIRKETT

DOCKET NO. 960001-EI

June 24, 1996

Q. Please state your name and address.

A. My name is Barry T. Birkett and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as the Manager of Rates and Tariff Administration.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the fuel factors for the Company's rate schedules for the period October 1996 through March 1997 and the capacity payment factors for the Company's rate schedules for the period October 1996 through September 1997. The calculation of the fuel factors is based on projected fuel cost and operational data as set forth in Commission

Schedules E1 through E10, H1 and other exhibits filed in this proceeding and data previously approved by the Commission.

In addition, my testimony presents the schedules necessary to support the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery Clause (FCR) and the Capacity Cost Recovery Clause(CCR) for the period April 1996 through September 1996.

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 various schedules included in Appendices II and III. Appendix II contains the FCR related schedules and Appendix III contains the CCR related schedules.

FCR Schedules A-1 through A-13 for April 1996 and May 1996 have been filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

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

A. Unless otherwise indicated, the actual data is taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices and provisions of the Uniform

System of Accounts as prescribed by this Commission.

FUEL COST RECOVERY CLAUSE

Q. **What is the proposed levelized fuel factor for which the Company requests approval?**

A. 2.037¢ per kWh. Schedule E!, Page 3 of Appendix II shows the calculation of this six-month levelized fuel factor. Schedule E2, Page 10 of Appendix II indicates the monthly fuel factors for October 1996 through March 1997 and also the six-month levelized fuel factor for the period.

Q. **Has the Company developed a six-month levelized fuel for its Time of Use rates?**

A. Yes. Schedule E1-D, Page 8 of Appendix II provides a six-month levelized fuel factor of 2.174¢ per kWh on-peak and 1.984¢ per kWh off-peak for our Time of Use rate schedules.

Q. **Were these calculations made in accordance with the procedures previously approved in this Docket?**

A. Yes, they were.

Q. **What adjustments are included in the calculation of the six-month levelized fuel factor shown on Schedule E1, Page 3 of**

Appendix II?

A. As shown on line 29 of Schedule E1, Page 3, of Appendix II the estimated/actual fuel cost underrecovery for the April 1996 through September 1996 period amounts to $88,480,000. This estimated/actual underrecovery for the April 1996 through September 1996 period plus the final underrecovery of $17,157,052 for the October 1995 through March 1996 period results in a total underrecovery of $105,637,052. This amount, divided by the projected retail sales of 36,766,446 MWH for October 1996 through March 1997 results in an increase of .2873¢ per kWh before applicable revenue taxes. In his testimony for the Generating Performance Incentive Factor, FPL Witness R. Silva calculated a reward of $1,980,538 for the period ending March 1996, to be applied to the October 1996 through March 1997 period. This $1,980,538 divided by the projected retail sales of 36,766,446 MWH during the projected period, results in an increase of .0054¢ per kWh, as shown on line 33 of Schedule E1, Page 3 of Appendix II.

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

A. Schedule E1-B, Page 5 of Appendix II shows the calculation of the FCR Estimated/Actual True-up amount. The calculation of the estimated/actual true-up amount for the period April 1996 through September 1996 is an underrecovery, including interest, of

$88,480,000 (Column 7, lines C7 plus C8). This amount, when combined with the Final True-up underrecovery of $17,157,052 (Column 7, line C9a) deferred from the period October 1995 through March 1996, presented in my Final True-up testimony filed on May 20, 1996, results in the End of Period underrecovery of $105,637,052 (Column 7, line C11).

This schedule also provides a summary of the Fuel and Net Power Transactions (lines A1 through A7), kWh Sales (lines B1 through B3), Jurisdictional Fuel Revenues (line C1 through C3), the True-up and Interest calculation (lines C4 through C10) for this period, and the End of Period True-up amount (line C11).

The data for April 1996 and May 1996, columns (1) and (2) reflects the actual results of operations and the data for June 1996 through September 1996, columns (3) through (6), are based on updated estimates.

The variance calculation of the Estimated/Actual data compared to the original projections for the April 1996 through September 1996 period is provided in Schedule E1-B-1, Page 6 of Appendix II.

As shown on line A5, the variance in Total Fuel Costs and Net Power Transactions is $108.1 million or a 14.5% increase. This variance is mainly due to a 22.6% increase in Fuel Cost of System Net Generation as shown on line A1a. This increase is primarily due to increases in natural gas and heavy oil prices reflecting the impacts of a colder than normal winter and extremely low crude oil and natural gas levels.

The true-up calculations follow the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" filed monthly with the Commission.

Q. **Is FPL requesting that any other costs be recovered through the Fuel Cost Recovery Clause?**

A. Yes. FPL is requesting that costs associated with two issues be recovered through the Fuel Cost Recovery Clause.

Q. **Please explain the first issue that FPL is requesting to be recovered through the Fuel Recovery Clause.**

A. FPL is requesting recovery of the costs associated with the thermal power uprate of Turkey Point Units 3 and 4. As discussed in the testimony of Claude Villard, the thermal power uprate of each nuclear unit, from 2200 megawatts thermal to 2300 megawatts thermal, will increase the output of each nuclear unit by approximately 31 megawatts electric. The units are expected to increase power by January 1997. As Mr. Villard testifies, the cost of this thermal power uprate project is estimated at $10 million.

The Company has estimated that this uprating will yield fuel savings on a net present value basis in excess of $88 million. From January 1997 through December 1998, the fuel savings are projected to exceed the cost of this project, therefore, FPL is requesting that it recover the depreciation and return on investment in this thermal power uprate project over this two year period. FPL has included $1,463,620 in the projected recovery factor for the upcoming period.

Q. What is the basis for requesting recovery of this thermal uprate project through the Fuel Cost Recovery Clause?

A. The Commission in Docket No. 850001-EI-B, Order No. 14546 issued on July 8, 1985 stated, regarding the charges appropriately included in the calculation of fuel "Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case by case basis after Commission approval".

This expenditure will result in significant fuel savings for FPL's customers and appears to be the type of a cost which the Commission contemplated being recovered through the clause. For these reasons, FPL believes that it is appropriate to bring this issue forward for Commission consideration and approval.

Q. Please explain the second issue that FPL is requesting to be recovered through the Fuel Recovery Clause.

A. A Petition was filed on February 15, 1996 under Docket No. 960182-EQ whereby, if approved, FPL will be recovering expenses associated with the settlement agreement to buy out the Cypress Energy Company Standard Offer Contract. If approved, Staff recommends that 42 percent of the actual annual settlement agreement payments should be recovered through the Fuel Cost Recovery Clause and 58 percent should be recovered through the Capacity Cost Recovery Clause.

The petition for approval to recover costs associated with the termination of the Standard Offer Contract is scheduled to go before the Commission on June 25, 1996, one day after this clause filing, therefore, per Staff's recommendation, FPL has included 42 percent, or $5,220,180 of the actual annual settlement agreement payments in the October 1996 through March 1997 Fuel Cost Recovery Clause and 58 percent, or $8,768,730 of the actual annual settlement agreement payments in the October 1996 through September 1997 Capacity Payment Recovery Clause.

CAPACITY PAYMENT RECOVERY CLAUSE

Q. **Is FPL proposing any changes to the implementation of the Capacity Cost Recovery Clause filing?**

A. Yes, it is. FPL is proposing that the Capacity Cost Recovery Clause filing be made on an annual basis rather than the current semi-annual basis.

Q. **Please explain why FPL is proposing this change?**

A. Filing on an annual basis will levelize the impact of the clause on our customers' rates since seasonal fluctuations in sales will be avoided. In addition, filing on an annual basis will greatly reduce the amount of paperwork produced, filed and processed by FPL, the Commission, and other parties.

Q. **Please describe Page 3 of Appendix IV.**

A. Page 3 of Appendix III provides a summary of the requested capacity payments for the projected period of October 1996 through March 1997. Total recoverable capacity payments amount to $430,838,159, and include payments of $207,711,591 to non-cogenerators, payments of $323,734,672 to cogenerators and $8,768,730 of Mission Settlement payments. This amount is offset by revenues from capacity sales of $2,600,155 and $56,945,592 of jurisdictional capacity related payments included in base rates plus the net overrecovery of

$42,305,151 reflected on line 9. The net overrecovery of $42,305,151 includes the final overrecovery of $28,927,083 for the October 1995 through March 1996 period less the estimated/actual overrecovery of $13,378,068 for the April 1996 through September 1996 period.

Q. **Will FPL be requesting recovery of any other costs through the Capacity Cost Recovery Clause?**

A. Yes. As discussed previously in the Fuel Recovery Clause section of my testimony and stated above, FPL has included 58 percent ($8,768,730) of the actual annual settlement agreement payments associated with the buy-out of the Cypress Energy Company Standard Offer Contract in the calculation of the Capacity Cost Recovery factor for the period October 1996 through September 1997.

Q. **Please describe Page 4 of Appendix III.**

A. Page 4 of Appendix III 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 Page 5 of Appendix III.**

A. Page 5 of Appendix III presents the calculation of the proposed

Capacity Payment Recovery Clause (CCR) factors by rate class.

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

A. Appendix III, page 6, shows the calculation of the CCR Estimated/Actual True-up amount. The Estimated/Actual True-up for the period April 1996 through September 1996 is an overrecovery, including interest, of $13,378,068 (Column 7, lines 14 plus 15). This amount, plus the Final True-up overrecovery of $28,927,083 (Column 7, line 17) deferred from the period October 1995 through March 1996, presented in my Final True-up testimony filed on May 20, 1996, results in the End of Period overrecovery of $42,305,151 (Column 7, line 19).

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

A. Yes it is. The calculation of the true-up amount follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery clause.

The resulting overrecovery of $42,305,151 has been included in the calculation of the Capacity Cost Recovery factor for the period October 1996 through September 1997.

Q. Please explain the calculation of the Interest Provision.

A. Appendix III, page 7, shows the calculation of the interest provision and follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission.

The interest provision is the result of multiplying the monthly average true-up amount (line 4) times the monthly average interest rate (line 9). The average interest rate for the months reflecting actual data is developed using the 30 day commercial paper rate as published in the Wall Street Journal on the first business day of the current and subsequent months. The average interest rate for the projected months is the actual rate as of the first business day in June 1996.

Q. Have you provided a schedule showing the variances between the Estimated/Actuals and the Original Projections?

A. Yes. Appendix III, page 8, shows the Estimated/Actual capacity charges and applicable revenues compared to the original projections for the period.

Q. What is the variance related to capacity charges?

A. The variance related to capacity charges is a $9.0 million decrease. This variance is primarily due to a $10.4 million decrease in Unit Power (UPS) Capacity Charges. This decrease is primarily due to prior period adjustments of $9.1 million reflected on the April and May invoices.

Q. What is the variance in Capacity Cost Recovery revenues?

A. As shown on line 13, Capacity Cost Recovery revenues, net of revenue taxes, are now estimated to be $2.7 million higher than originally projected.

Q. What effective date is the Company requesting for the new factors?

A. The Company is requesting that the new FCR factors become effective with customer billings on cycle day 3 of October 1996 and continue through Customer billings on cycle day 2 of March 1997 and that the new CCR factors become effective with customer billings on cycle day 3 of October 1996 and continue through cycle day 2 of September 1997. This will provide for 6 months of billing on the FCR factors and 12 months of billing on the CCR factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective October 1996?

A. The total residential bill, excluding taxes and franchise fees, for 1,000 kWh will be $77.12. The base bill for 1,000 residential kWh is $47.46, the fuel cost recovery charge from Schedule E1-E, Page 9 of

Appendix II for a residential customer is $20.41, the Conservation charge is $2.09, the Capacity Cost Recovery charge is $6.21, the Environmental Cost Recovery charge is $.17 and the Gross Receipts Tax is $.78. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10, Page 39 of Appendix II.

Q. Does this conclude your testimony.

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. L. WADE

DOCKET NO. 960001-EI

June 24, 1996

Q Please state your name and address.

A. My name is Robert L. Wade. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Director, Business Services in the Nuclear Business Unit.

Q. Briefly describe your educational background and employment history.

A. I received a Bachelor of Science degree in Physics and Engineering from Washington and Lee University in 1973. I received a Masters in Business Administration from the University of Hartford in 1982. I served as a U.S. naval officer from 1973 to 1979. From 1979 to 1989 I was employed by Combustion Engineering, Inc. of Windsor

Connecticut, in various engineering related positions.

Since 1989 I have been employed by FPL, first in engineering and since 1991, in Business Services. In my current position I am responsible for business and financial planning in the business unit, business unit level computer services, and business unit level nuclear plant access, radiation protection, and emergency preparedness activities.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to discuss outages at St. Lucie Units 1 and 2 during the period September 1994 through September 1995.

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

A. Yes, I have. It is labelled Document No. 1.

Q. **Were these outages at the St. Lucie Units 1 and 2 during the period September 1994 through September 1995 an issue during the February 1996 Fuel proceeding?**

A. Yes. The issue: Should FPL recover replacement energy costs resulting from outages at the St Lucie Plant during the period September 1994 through September 1995, was raised by the Commission Staff during the February 1996 Fuel proceeding. FPL believes its actions regarding these outages were reasonable and prudent and, therefore, FPL should recover all replacement energy costs. The issue was deferred from the February 1996 hearing to allow time for additional discovery.

Q. Has FPL filed any discovery responses with the Commission concerning this issue?

A. Yes. On November 3, 1995, FPL filed responses to Staff's Third Set of Interrogatories. These interrogatory responses provide a detailed description of the incidents which occurred from September 1994 through September 1995 at the St. Lucie plant that affected the operation of the units and the corrective actions taken by FPL. Additionally, some of the responses describe the actions taken at the St. Lucie Plant due to the threat of Hurricane Erin. The responses to Staff's Third Set of Interrogatories, Nos. 15 - 18 and 20 - 21 are attached as Document No. 1 to my testimony. The replacement energy costs included in response to Interrogatory No. 21 have been provided by FPL witnesses Barry Birkett and Rene Silva.

Q. Does FPL plan to supplement this filing?

A. Yes. Recently the Commission Staff asked additional questions and requested updates on the interrogatory responses. FPL is currently working on Staff's requests and plans to supplement this filing in the near future.

Q. Does this conclude your testimony?

A. Yes, it does.

DOCUMENT NO. 1
FLORIDA POWER AND LIGHT COMPANY
RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES
NOS. 15, 16, 17, 18, 20, AND 21

RLW-1
DOCKET NO. 960001-EI
FPL WITNESS: R. L. WADE
EXHIBIT______
PAGES 1 - 25
JUNE 24, 1996

15. Q. On what date and at what time(s) were the St. Lucie nuclear units taken off line due to Hurricane Erin?

A. St. Lucie Unit 1 was taken off line on August 1, 1995 at 14:55 hours. St. Lucie Unit 2 was taken off line on August 1, 1995 at 11:28 hours.

16. Q. Were these times based on procedures prescribed by a regulatory agency? If yes, please identify the regulatory agency.

A. The times were based on FPL procedures developed to comply with the Nuclear Regulatory Commission's (NRC) Station Blackout Rule as specified in Chapter 10, Part 50.63 of the Code of Federal Regulations (CFR).

The Station Blackout Rule was developed to provide assurance that nuclear plants have sufficient equipment and procedural guidance to safely maintain critical plant functions during time periods when they may not be able to generate electricity concurrent with periods when the availability of off site power is questionable.

In complying with the requirements of the Station Blackout Rule, FPL committed to the NRC to commence the shutdown of the St. Lucie units prior to the projected onset of hurricane force winds.

17. Q. When the St. Lucie nuclear units are taken off line due to a threatening hurricane, what length of time is required to return the units to service?

A. The length of time to return a unit to service after the passing of a hurricane varies depending on the amount of damage incurred and the outcome of key start up activities. After the passage of a Hurricane, site damage assessment as well as two primary start up areas must be addressed. One area is the Site Emergency Plan and the second is normal plant start up operations.

The first step in unit start up involves plant damage assessment to determine the extent of plant damage and required repairs, if repairs are required, to ensure safe operations of plant. In addition to damage assessment, St. Lucie is required by their Technical Specifications to maintain an emergency plan. The plan requires several activities be completed prior to unit start up. Emergency plan activities include:

1. Equipment defined in the technical specifications has been returned to service. This includes both plant equipment as well as off site equipment such as the public warning sirens.
2. The equipment and processes defined in the plant Radiological Emergency Plan have been assessed and found to be acceptable.

In addition to the responsibilities of FPL, the State of Florida Radiological Emergency Management Plan for nuclear power plants specifies actions for local governments in support of plant operations. These agencies include the State Division of Emergency Management, the department of Health and Rehabilitative Services, Office of Radiation Control and all risk counties (those counties within ten miles of the plant).

State and local government must be able to adequately implement their radiological emergency plans following a storm. Activities performed at the State and local government level include:

1. Ensure the Emergency Broadcast System is available.
2. Adequate shelter capacity and support exists.
3. Adequate manpower is available.
4. Adequate transportation is available for those with special needs.

In addition to activities required under the Emergency Plan, the plant must follow normal plant start up procedures.

Plant start up from cold shut down involves numerous activities. The unit goes through a series of modes (Mode Five to Mode One) until the unit is placed back in service. A summary of the key start up activities include:

1. RCS is heated and pressure maintained via the pressurizer heaters and reactor coolant pumps.
2. Mode Four is reached when RCS temperature reaches 200F.
3. Unit enters Mode Three once RCS temperature reaches 325F. This mode is called hot standby.
4. From Mode Three to Mode One involves reactor start up. Once the desired operating temperature is reached, the control rods are withdrawn from the core and the reactor becomes critical.
5. Turbine start up is initiated. Steam lines are warmed and vacuum is established in the condensers.
6. Main generator start up is initiated.

As reactor power is slowly increased numerous tests are performed. The unit is brought up to full power through a series of hold points until 100% power is reached.

During the entire start up process, numerous tests are conducted on auxiliary and safety systems to ensure normal operation. These tests may identify components which require corrective actions be performed. These actions may affect the time required to return the unit to service.

18. Q. Did Hurricane Erin cause any damage to either of the St. Lucie nuclear units?

A. No.

20. Q. Please provide the names, titles and company affiliation of each member of the outside team of utility experts that recently assessed the performance of Florida Power and Light Company's St. Lucie nuclear power plants.

A. R.J. Hovey, Assistant Site Vice President Turkey Point Nuclear Plant, Florida Power and Light Co.

R.K. Edington, Plant Manager Arkansas Nuclear One, Entergy Operations, Inc.

W.R. Matthews, Assistant Station Manager North Anne Power Station, Virginia Electric and Power Company.

J.T. Voorhees, Quality Assurance Supervisor St. Lucie Nuclear Plant, Florida Power and Light Co.

The team was formed of three off site managers, two from outside FPL and one from the Turkey Point Nuclear Station, and one on site employee. This composition provided familiarity with St. Lucie plant personnel and procedures coupled with the independence of non FPL expertise.

21. Q. Please provide a detailed description of each incident occurring from September, 1994, to the current date at the St. Lucie plant that affected the operation of either nuclear unit. The description should include, but not limited to the following:

a. the cause of the incident
b. the corrective action steps taken by the company:
   i. person/company correcting the problem
   ii. cost to correct the problem (parts and labor)
   iii. environmental impacts
c. a timeline that indicates when each corrective action step was completed
d. source of replacement energy
e. total KWH's purchased/generated of replacement energy
f. total cost of replacement energy
g. fuel cost of replacement energy

A. a,b,c. See pages 3 through 19 of this response (pages numbers corresponding to each event are provided in the table below)

d. During each incident that affected the operation of the St. Lucie plant, FPL's source of replacement energy was from FPL system resources. Since the replacement energy came from FPL's system output, it cannot be specifically tied to any particular FPL generating unit.

e, f, g. See table below

ST LUCIE UNIT NO.	DATE	EVENT	For (a) (b) (c) See Page	(e) REPLACEMENT ENERGY kWh	(f) & (g) COST (see notes 1,2 & 3 below)
1	Oct 26-94	Potential Transformer	3	7,210	$120,835
1	Feb 27-95	Quench Tank In Leakage	4	163,667,000	$2,264,639
1	Jul 8-95	Turbine Trip During Surveillance Testing	5	36,050,000	$615,742
1	Jul 10-95	External Event, Vehicle in Discharge Canal	6	25,235,000	$417,900
1 and 2	Aug 1-95	External Event, Hurricane Erin	7	68,571,000	$1,054,361
1	Aug 2-95	1A2 Reactor Coolant Pump Seal Package Failure	8	124,012,000	$2,123,006
1	Aug 9-95	Power Operated Relief Valve Failures	9-10	134,883,000	$2,577,776

ST LUCIE UNIT NO.	DATE	EVENT	For (a) (b) (c) See Page	(e) REPLACEMENT ENERGY kWh	(f) & (g) COST (see notes 1,2 & 3 below)
1	Aug 17-95	Inadvertent Spray Down of Containment	11	246,024,000	$4,179,840
1	Sep 1-95	1B2 EDG Rocker Arm Adjusting Screw Lock Nut	12	186,739,000	$2,844,879
1	Sep 11-95	Pressurizer Code Safety Valve Flange Leakage	13	124,733,000	$2,086,873
1	Sep 19-95	1B Emergency Diesel Generator Hold Down Bolts	14	51,191,000	$824,809
1	Sep 22-95	1A & 1B EDG Governor Stability	15	46,307,000	$748,007
1	Sep 24-95	Pressurizer Code Safety Valve Alignment Modifications	16	325,892,000	$5,208,977
2	Feb 21-95	Steam Generator Level Transmitter Failure	17	53,876,000	$637,288
2	Apr 25-95	Digital Electro-Hydraulic Power Supply Failure	18	5,456,000	$70,814
2	Aug 4-95	Switchyard Circuit Breaker Failure	19	9,548,000	$166,098

Assumptions:

1) Total KWH replacement energy based upon net to FPL from: a) PSL1 of 776MW per hour less projected forced outage rate and projected maintenance outage rate of 3.1% and 4%, respectively and b) PSL2 of 777 megawatts per hour less projected forced outage rate and projected maintenance outage rate of 9.9% and 2.3%, respectively. The projected outage rates are taken from the Fuel Cost Recovery filing of June 1995. The resultant output (721 and 682 for PSL#1 and PSL#2) was considered the energy to be replaced for each hour the unit was off-line.

2) Total Cost and Fuel Cost are equal since there was no capacity purchased to replace PSL output.

3) The replacement fuel cost based upon the FPL hourly system lambda (cost of next megawatt) adjusted for the decremental block of energy assumed in assumption 1 above. The average cost of PSL energy ($per megawatt hour) was assumed to be $5.58 and $6.75 for PSL#1 and PSL#2 respectively. The PSL cost was subtracted from the adjusted FPL hourly system lambda and was multiplied by the replacement energy.

Event: Potential Transformer

St. Lucie Unit 1

Event date: October 26, 1994

On October 26, 1994, Unit 1 was in Mode 1 and operating at 100% power. At 2:26 P.M., an arc was observed in the area of the 240 KV switchyard near the Unit 1 synchronizing potential transformer. Concurrently, Unit 1 experienced an automatic reactor trip on loss of electrical load predicated by main generator differential current condition. Standard post trip actions were performed, the normal Reactor Trip Recovery procedure was implemented and all safety functions were satisfactory. Subsequently, at 2:45 P.M., a fire was reported at the potential transformer outside the protected area. The fire was controlled and allowed to extinguish itself.

The root cause of this event was determined to be an external fault across the porcelain insulator of the synchronizing potential transformer which resulted in a flashover of the insulator. The flashover resulted from a combination of marginal basic insulation level of the transformer contributed to by salt contamination of the insulator.

The following actions were taken by FPL to correct the problem:

1. The synchronizing potential transformer was replaced with a new 900KV BIL rated model of increased strike distance for enhanced insulating capability.
2. The Unit 1 switchyard components were inspected and no other degraded components were found.
3. Schedules were establish to periodically apply silicone coatings to both units synchronizing potential transformers.
4. The main transformer, main generator and isophase bus were inspected with satisfactory results.
5. An upgraded synchronizing potential transformer utilizing a 1050 KV insulation level was installed in the February 1995 Quench Tank In Leakage outage.

Initial corrective actions were completed by October 26, 1994. A total of 9:33 off-line hours were attributed to this event. There were no off-site environmental issues associated with this event.

The cost to replace the transformer and perform the required inspections was approximately $74,000. The corrective actions were performed by FPL employees.

Event: Quench Tank In Leakage

St. Lucie Unit 1

Event date: February 27, 1995

Beginning in December 1994, the rate of in leakage to the quench tank began to trend upward. It soon became evident that the leakage rate would eventually approach the Technical Specification Reactor Coolant System (RCS) leakage limit, requiring a mid-cycle outage to correct the problem. A task team was established to identify contributing factors to the in leakage and develop and implement appropriate corrective actions. On February 27, 1995, St. Lucie Unit 1 was removed from service to implement the corrective actions identified by the task team.

The primary source of in leakage to the quench tank was determined to be associated with leakage from the pressurizer code safety valves. The valves were leaking between their discs and seats. The major contributors to this leakage were:

1. Insufficient margin between normal system operating pressure and the valves lift set point.
2. High ambient temperature.
3. Valve body flexure from thermal stresses during plant heat up.

The following actions were taken by FPL to correct the problem:

1. All three pressurizer code safety valves were replaced.
2. Pressurizer head insulation was modified to improve ambient conditions of the code safety valves.
3. The pressurizer missile shield was removed to improve the ambient conditions of the code safety valves.
4. Pressurizer pressure was raised slowly over a 24 hour period allowing the valves to soak at each step.

A long term solution to code safety valve leakage is addressed in event "Pressurizer Code Safety Valve Alignment Modifications".

A total of 157:58 off-line hours, excluding normal start up, were attributed to this event. St. Lucie Unit 1 was successfully returned to service on March 8, 1995. There were no off site environmental issues associated with this event.

The cost to replace the pressurizer code safety valves as well as modifications to the pressurizer was approximately $896,000. The work was by performed FPL employees as well as Crosby Valve and Gage Co. and Wyle Laboratories.

Event: Turbine Trip During Surveillance Testing

St. Lucie Unit 1

Event date: July 8, 1995

On July 8, 1995, Unit 1 was in Mode One and operating at 100% power. Operations personnel were conducting a scheduled turbine overspeed trip surveillance per approved plant procedures. During the portion of the surveillance that tests a solenoid valve for overspeed protection control, an operator failed to close an isolation valve prior to continuing with the test. Failure to close the valve allowed electro-hydraulic (EH) fluid to drain from the governor and intercept valves when the solenoid valve was opened during a subsequent step. Draining the EH fluid caused closure of the main turbine governor and intercept valves, resulting in a turbine trip followed by an automatic reactor trip.

The root cause of this event was the performance of surveillance test steps out of sequence.

The following actions were taken by FPL to correct the problem:

1. Normal post trip actions were taken to ensure plant equipment responded as designed and operated properly.
2. Normal plant start up activities were performed to return the unit to service.

A total of 50:58 off-line hours were attributed to this event. There were no off site environmental issues associated this event.

There were no repair costs associated with this event.

Event: External Event, Vehicle In Discharge Canal

St. Lucie Unit 1

Event date: July 10, 1995

On July 9, 1995 with Unit 2 at 100% power and Unit 1 in start up Mode Three, a vehicle entered FPL property through an open gate off Highway A1A. Although the entrance was clearly marked with a "NO TRESPASSING VIOLATORS WILL BE PROSECUTED" sign, the driver proceeded east along the access road adjacent to the intake canal. The driver turned north until he encountered a locked gate. After making a U-turn, the vehicle proceeded up and over the berm of the discharge canal, ultimately entering the discharge canal. The occupants of the vehicle exited the vehicle prior to it submerging and climbed up a ladder located on the North side of the discharge headwall.

The vehicle was located inside the discharge pipe approximately 50 feet from the ocean end of the pipe. Flow through the discharge pipe was slowed to allow divers to enter the pipe and re-position the vehicle and extract it from the discharge pipe on July 11, 1995. The vehicle was subsequently towed, by tug boat, to a terminal dock in Ft. Pierce.

The root cause of this event was determined to be the vehicle driver's disregard of a clearly posted no trespassing sign on FPL property at the entrance to the canal area.

A security analysis was conducted of areas within the owner controlled area to determine where enhanced security measures could be implemented to preclude such incidents in the future. One preventative measure identified was to lock all gates which allow access to FPL property.

The introduction of the vehicle into the discharge canal delayed the start up of Unit 1 by 29:45 hours excluding normal start up. The incident did not affect the operation of Unit 2. There were no off site environmental issues resulting from this event. A report of the event was filed with the appropriate State environmental agencies.

The cost to remove the vehicle from the discharge pipe was approximately $37,000 and was accomplished by FPL employees and Underwater Engineering Service, Inc.

Event: External Event, Hurricane Erin

St. Lucie Unit's 1 and 2

Event date: August 1, 1995

On July 31, 1995 at 11:14 A.M., with both St. Lucie nuclear units at 100% power, the National Hurricane Center issued a hurricane warning which encompassed the St. Lucie plant site. On August 1, 1995, information from the National Hurricane Center forecast sustained hurricane force winds at the St. Lucie plant site. In accordance with the Site Emergency Plan, site management directed the commencement of a controlled shut down of St. Lucie Units 1 and 2. St. Lucie unit 1 was taken off line on August 1, 1995 at 2:55 P.M. St. Lucie Unit 2 was taken off line on August 1, 1995 at 11:28 A.M. Both units were shut down by 2:00 P.M.

Hurricane Erin passed approximately 20 miles to the North of the St. Lucie plant on August 2, 1995 at 1:00 A.M. After damage assessment and emergency plan actions were concluded, the decision to return both units to service was made. Unit 2 returned to service on August 5, 1995 at 12:52 A.M. Unit 1's return to service was initially delayed by the failure of the 1A2 Reactor Coolant Pump seal.

The off-line hours directly attributable to Hurricane Erin for both units was 98:19.

The cost incurred for Hurricane Erin St. Lucie plant preparation was approximately $282,000. The preparation efforts were performed by FPL employees and Raytheon Constructors Inc.

Event: 1A2 Reactor Coolant Pump Seal Package Failure

St. Lucie Unit 1

Event date: August 2, 1995

On August 2, 1995, while Unit 1 was in start up Mode Three following a shutdown due to Hurricane Erin, operators detected the 1A2 Reactor Coolant Pump (RCP) lower seal had failed. In accordance with approved procedures, attempts were made to return the seal to service while maintaining the unit in Mode Three. The procedure sequentially de-pressurizes the seal cavities from top to bottom in order to introduce a differential pressure across the leaking seal thereby restaging it. The attempt to restage the lower seal failed. As a result, operators cooled down and de-pressurized the reactor coolant system in accordance with plant operating procedures.

The root cause of the seal failure is currently under investigation.

The following actions were taken by FPL to correct the problem:

1. The 1A2 RCP seal was replaced.
2. Engineering is performing a root cause evaluation of the seal failure.

A total of 120:11 off-line hours, excluding normal plant start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the 1A2 RCP seal was approximately $1,184,000. The repair effort was performed by FPL employees and Raytheon Constructors.

Event: Power Operated Relief Valve Failures

St. Lucie Unit 1

Event date: August 9, 1995

On August 9, 1995, Unit 1 was in start up Mode Four following a shut down due to Hurricane Erin. Stroke testing of the Pressurizer Power Operated Relief Valves (PORV) was being performed in accordance with an approved plant procedure. During testing, operators could not confirm that the PORV's were opening as expected. The valves were declared inoperable and a plant cool down and de-pressurization was performed. Both PORV's were removed from the pressurizer. The valves were functionally tested and did not open as expected. The valves were subsequently disassembled and the main disc guides were found to be installed improperly.

The root cause of the PORV inoperability was determined to be improper re-assembly of the PORV's following overhaul during the 1994 refueling outage.

The following actions were taken by FPL to correct the problem:

1. Both PORV's were removed and re-assembled correctly.
2. Changes were made to the Power Operated Relief Valve maintenance procedure to verify, during bench testing, that the main valve disc actuates when test pressure is applied and to add a verification that the main disc guide is installed with the correct orientation.
3. A change was made to the procedure for conducting in service testing on the PORV's to require more positive indication of PORV main valve actuation by using quench tank and pressurize parameters for confirmation during testing.
4. Other activities performed by the same contractor were reviewed. No other equipment operability issues were identified.
5. Unit 2 PORV's were determined not to be susceptible to a similar event; The valve configuration on Unit 2 PORVs does not allow for the main disc guide to be installed improperly.
6. Plant Staff and Engineering will perform a review of post maintenance testing on other safety related equipment to ensure the testing adequately demonstrates component operability.
7. A comprehensive review of and modification to procedures pertaining to control of contractors will be performed.

A total of 145:17 off-line hours, excluding normal plant start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to remove, re-assemble and re-install the PORV's was approximately $381,000. The corrective measures were implemented by FPL employees.

Event: Inadvertent Spray Down Of Containment

St. Lucie Unit 1

Event date: August 17, 1995

On August 11, 1995, a containment spray (CS) header control valve failed its stroke test and was declared out of service. Pending repair of the valve, the valve was placed in its safeguards position of open.

On August 17, 1995, with Unit 1 in start up Mode Three, the Emergency Core Cooling System (ECCS) venting procedure for the Low Pressure Safety Injection System (LPSI) was started. As part of that procedure, an operator started the 1A LPSI pump and established a flow path through the Shutdown Cooling System (SDC) heat exchanger. These actions provided a direct flow path from the Refueling Water Tank (RWT) to the "A" CS header and the open header control valve. Approximately 10,000 gallons of borated water was inadvertently sprayed into containment through the "A" CS header using the 1A LPSI pump.

Operators secured the 1A LPSI pump and isolated the 1A SDC heat exchanger and drained the reactor sump to the Aerated Waste Storage Tank.

The root cause of this event was identified as a procedural deficiency in the ECCS venting procedure, which did not require operators to verify that the proper CS header isolation valves were closed prior to recirculating the water in the SDC system.

The following actions were taken by FPL to correct the problem:

1. Plant equipment impacted by the borated water spray was cleaned, inspected and repaired or replaced as required.
2. The ECCS and CS venting procedure was revised to provide limitations on plant conditions during venting.
3. The CS header isolation valve was repaired and returned to normal status.

A total of 343:31 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost of this event, including containment clean up was approximately $966,000. The clean up effort was performed by FPL employees.

Event: 1B2 EDG Rocker Arm Adjusting Screw Lock Nut

St. Lucie Unit 1

Event date: September 1, 1995

On August 31, 1995, operations personnel were conducting a one hour Emergency Diesel Generator (EDG) surveillance run in accordance with procedures. Unit 1 was in Mode Five following the containment spray incident. After the EDG reached a rated speed of 900 RPM, the 1B EDG tripped on high crankcase pressure from the 1B2 engine. Inspections revealed that the number nine power pack piston and cylinder head had sustained damage due to separation of the exhaust valve head from its stem. The failed valve head, loose within the combustion chamber, punctured the piston and cylinder head. Damage was also observed in several exhaust valve train parts.

The most probable root cause of the EDG failure was the exhaust valve rocker arm adjusting screw lock nut had loosened.

The following actions were taken by FPL to correct the problem:

1. The 1B2 EDG engine was repaired, cleaned and inspected.
2. All EDG engines were inspected for exhaust valve rocker arm lock nut torque.
3. Technical manuals were updated to include a minimum torque check verification of 50 foot pounds for the adjusting screw lock nut.
4. Failed engine components have been sent to the original manufacturer to determine root cause of the equipment failure.

A total of 258:11 off-line hours, commencing on September 1, 1995, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to repair the 1B2 EDG was approximately $280,000. The repair effort was performed by FPL employees and MKW Power Systems, Inc.

Event: Pressurizer Code Safety Valve Flange Leakage

St. Lucie Unit 1

Event date: September 11, 1995

On September 11, 1995, with Unit 1 in start up Mode Three, a Reactor Coolant System leak inspection was performed. During the inspection, it was noted that the inlet flange of Pressurizer Code Safety Valve (PCSV) 1201 was leaking. In order to repair the valve, the unit was cooled down and de-pressurized to Mode Five.

The apparent root cause of the leakage was found to be the use of flexicarb spiral wound model gaskets without the concurrent use of a crush stop to prevent plastic deformation in tongue and groove applications. This results in the gasket material assuming most of the pre load of the flange bolting. In addition, Engineering determined that the procedural torque specification for bolting was excessive for this application.

The following actions were taken by FPL to correct the problem:

1. PCSV 1201, as well as the other two PCSV's, were re-installed with gaskets designed to operate without a crush stop (Kammprofile gaskets).
2. A lower torque value of 500 foot pounds was incorporated into the PCSV maintenance procedure.
3. An improved PCSV bolt up process has been incorporated into maintenance procedures.
4. A review of generic applications of flexicarb gaskets and their misuse is underway.
5. Kammprofile gaskets have been procured for Unit 2 and will be installed during the current Unit 2 outage.

A long term solution to code safety valve leakage is addressed in event "Pressurizer Code Safety Valve Alignment Modifications".

A total of 70:25 off-line hours, excluding normal start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to repair the three PCSV's, as well as perform the modifications outlined in event "Pressurizer Code Safety Valve Alignment Modifications" was approximately $190,000. The repair work was performed by FPL employees and Crosby Valve and Gage Co.

Event: 1B Emergency Diesel Generator Hold Down Bolts

St. Lucie Unit 1

Event date: September 19, 1995

On September 19, 1995, during a surveillance of the 1B Emergency Diesel Generator (EDG), an operator found a bolt head broken off.

The failed bolt head was sent to the FPL metallurgical lab for evaluation. Based upon observed field conditions, EDG design knowledge and failure analysis, it was determined the bolt failed under high cycle fatigue. Contributing factors to the fracture were normal vibration energy, the mounting bolt being partially unloaded as a result of the exhaust valve rocker arm adjusting screw lock nut failing (see "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event) and the bolt being previously machined to remove threads in the base plate area.

The following actions were taken by FPL to correct the problem:

1. The failed bolt was replaced.
2. An ultrasonic evaluation was performed on all bolting on all site EDG engines. No evidence of cracking or shearing was found.
3. All site EDG engine bolt torques were verified.
4. A standard mounting detail will be developed for all eight EDG engines.

A total of 71:27 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the failed bolting is included in the "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event. The repairs were performed by FPL employees.

Event: 1A and 1B EDG Governor Stability

St. Lucie Unit 1

Event date: September 22, 1995

On September 21, 1995, with St. Lucie Unit 1 in Mode Five, preparing for Mode Four, the 1B Emergency Diesel Generator (EDG) was started to perform a test run. After several minutes of operation, the 1B EDG governor experienced load oscillations. On September 22, 1995, the 1A EDG also experienced similar governor load swings during testing.

The root cause of the EDG governor load swings was primarily attributed to problems associated with the motor operated potentiometer within the governor.

The following actions were taken by FPL to correct the problem:

1. The motor operated potentiometer was replaced on both the 1A and 1B EDG'S.
2. The governor amplifier, load sensor and frequency sensor were replaced on the 1A EDG.
3. Adjusted governor controls on both the 1A and 1B EDG's.
4. Cleaned and inspected EDG governor components.

A total of 66:13 off-line hours, commencing on September 22, 1995, were attributed to this event. The 1A EDG was returned to service on September 23, 1995. The 1B EDG was returned to service on September 24, 1995. There were no off site environmental issues associated with this event.

The cost to repair the 1A EDG and the 1B EDG is included in the "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event. The repair effort was performed by FPL employees.

Event: Pressurizer Code Safety Valve Alignment Modifications

St. Lucie Unit 1

Event date: September 24, 1995

On September 26, 1995, during Unit 1 heat up, instrumentation indicated leakage from Pressurizer Code Safety Valve (PCSV) 1202. Reactor Coolant System (RCS) pressure was reduced and PCSV 1202 appeared to reseat. On September 27, 1995, with (RCS) pressure at 2230 psia, a minimal amount of leakage was identified in PCSV's 1201 and 1202. As RCS pressure increased, the leakage rate accelerated. A unit cool down and de-pressurization was initiated.

The primary root cause of the valve leakage was determined to be operating load stress placed on the valve by associated tail piping.

The following actions were taken by FPL to correct the problem:

1. All three PCSV's were replaced with valves which had recently been refurbished.
2. The tail pipe supports were modified to reduce operating loads placed on the PCSV's.
3. The refurbished PCSV's were installed in locations where the unit operated without leakage in the past.
4. Heat up procedures were revised to allow additional time for associated piping to achieve thermal equilibrium.

The cause of PCSV leakage has been studied in the nuclear industry and by FPL for some time. FPL determined a long term solution to the leakage problems to be the replacement of PCSV's with a newly designed valve. The new valve is manufactured out of forged steel utilizing a block body design which provides greater strength and will make the new valves less susceptible to tail pipe operating stress . The new valves will be installed in Unit 1 during the 1996 refueling outage.

A total of 341:15 off-line hours, commencing on September 24, 1995, excluding normal plant start up, were attributed to this event. St. Lucie Unit 1 was successfully returned to service on October 13, 1995. There were no off site environmental issues associated with this event.

The cost to replace the PCSV's and perform the modifications to the tail pipe supports is included in event "Pressurizer Code Safety Valve Flange Leakage". The repairs were performed by FPL employees and Crosby Valve and Gage Co.

Event: Steam Generator Level Transmitter Failure

St. Lucie Unit 2

Event date: February 21, 1995

On February 21, 1995, Unit 2 was in Mode One at 100% power. At 1:17 PM, Unit 2 automatically tripped due to low water level in the 2A Steam Generator. In accordance with plant procedures, standard post trip and reactor trip activities were performed. Normal steam generator water levels were regained and Unit 2 was stabilized in Mode Three.

The low water level in the 2A Steam Generator was due to a level transmitter which had failed high. The most likely root cause of the level transmitter failure, as determined by the design vendor, was coalescing of microscopic conductive particulates in the fill fluid which acted as a short circuit between the center diaphragm of the transmitter and one of the sensor cell capacity plates.

The following actions were taken by FPL to correct the problem:

1. The level transmitter was replaced with a newly manufactured transmitter.
2. The corresponding level transmitter on the 2B Steam Generator was replaced.
3. The failure was reviewed to prevent similar failures on other plant transmitters.
4. Engineering packages were completed to provide for additional margins in steam generator low level pre-trip alarms.

A total of 78:43 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the failed level transmitter was approximately $229,000. The repairs were performed by FPL employees.

Event: Digital Electro-Hydraulic Power Supply Failure

St. Lucie Unit 2

Event date: April 25, 1995

On April 12, 1995, with Unit 2 in Mode One at 100% power, annunciation in the control room indicated trouble with one of the six power supply units within the Digital Electro-Hydraulic (DEH) cabinet. Site personnel investigated and found the output of one of the power supply units was zero. Since the replacement of the power supply unit at full power may have resulted in a unit trip, the plant was taken out of service on April 25, 1995 to replace the DEH power supply unit.

The root cause of the DEH power supply unit failure was determined to be the failure of a resister within the power supply unit. The failure was determined to be an isolated incident as analysis revealed no such failure of this type of power supply in approximately 50 years of industry use.

The following actions were taken by FPL to correct the problem:

1. The DEH power supply unit was replaced along with the associated crow bar circuit and in-line fuse holder.
2. An inspection was made of the remaining power supply units.

A total of 7:21 off-line hours were attributed to this event. St. Lucie Unit 2 was successfully returned to service on April 25, 1995. There were no off site environmental issues associated with this event.

The cost to replace the failed power supply and associated hardware was approximately $4,000. The repairs were performed by FPL employees.

Event: Switchyard Circuit Breaker Failure

St. Lucie Unit 2

Event date: August 4, 1995

With St. Lucie Unit 2 in Mode One during start up after Hurricane Erin, plant operators attempted unsuccessfully to automatically synchronize the main generator to the grid. During a second synchronization attempt, a generator circuit breaker momentarily closed, re-opening when the synchroscope needle indicated the generator was approximately 30 degrees out of phase with the grid's frequency.

The most likely root cause of this event was a slowly opening solenoid operated pilot valve on the pneumatic actuator on a generator circuit breaker. The pilot valve probably had its plug momentarily stick, causing the circuit breaker to operate too slowly and close in after the generator and the grid had gone out of phase.

The following actions were taken by FPL to correct the problem:

1. The pilot valve for the generator circuit breaker was replaced.
2. Troubleshooting on the main generator automatic synchronization circuitry and relays was performed with satisfactory results.
3. Circuit breakers were tested for satisfactory operation.
4. The incident was evaluated for Unit 1 considerations but was determined not to be applicable to the Unit 1 generator.
5. Westinghouse Electric evaluated the potential damage to the main generator and determined that the conditions experienced during the event were within the design ratings of the generator.
6. FPL will replace the air operated pilot valves with a different model during the current Unit 2 refueling outage.

Corrective actions were completed by August 5, 1995. A total of 14:08 off-line hours were attributed to this event. St. Lucie Unit 2 was successfully returned to service on August 5, 1995. There were no off site environmental issues concerning this event.

The cost to replace the pilot valves was approximately $4,000. The corrective actions were performed by FPL employees.

APPENDIX I

FUEL COST RECOVERY

FORECAST ASSUMPTIONS

RS-1
DOCKET NO 960001-EI
FPL WITNESS: R. SILVA
EXHIBIT ___________
PAGES 1- 7
June 24, 1996

APPENDIX I
FUEL COST RECOVERY
FORECAST ASSUMPTIONS

TABLE OF CONTENTS

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL ($/BBL)

OCTOBER, 1996 THROUGH MARCH, 1997

	1996			1997		
BY SULFUR GRADE	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
0.7% SULFUR	$19.25	$18.36	$17.43	$17.97	$17.41	$17.31
1.0% SULFUR	$18.07	$17.04	$16.05	$16.54	$16.29	$16.15
2.0% SULFUR	$17.64	$16.70	$15.56	$15.92	$15.63	$15.49
2.5% SULFUR	$17.43	$16.54	$15.32	$15.62	$15.31	$15.17

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT OIL ($/BBL)

OCTOBER, 1996 THROUGH MARCH, 1997

	1996			1997		
BY SULFUR GRADE	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
0.3% SULFUR	$26.29	$25.21	$23.11	$24.95	$24.51	$23.35
0.5% SULFUR	$24.77	$23.79	$21.59	$23.43	$22.99	$21.82

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

OCTOBER, 1996 THROUGH MARCH, 1997

	1996			1997		
FUEL TYPE	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
COAL	$1.50	$1.50	$1.50	$1.51	$1.51	$1.51

FLORIDA POWER & LIGHT COMPANY

PROJECTED TOTAL NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

OCTOBER, 1996 THROUGH MARCH, 1997

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	1996			1997		
	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
FIRM	480	455	455	455	455	455
NON-FIRM	265	265	265	255	255	255

DISPATCH WEIGHTED AVERAGE UNIT PRICE BY TYPE OF TRANSPORTATION SERVICE ($/MMBTU)

FIRM	$1.98	$2.00	$2.10	$1.87	$1.64	$1.47
NON-FIRM	$2.71	$2.78	$2.90	$2.62	$2.33	$2.12

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
OCTOBER, 1996 THROUGH MARCH, 1997

PLANT/UNIT	PROJECTED FORCED OUTAGE FACTOR (%)	PROJECTED MAINTENANCE OUTAGE FACTOR (%)	PLANNED OUTAGE FACTOR (%)	OVERHAUL DATES *	
Cape Canaveral 1	2.0	4.5	0.0	NONE	
Cape Canaveral 2	2.0	5.3	0.0	NONE	
Cutler 5	2.0	2.0	0.0	NONE	
Cutler 6	3.0	2.4	0.0	NONE	
Lauderdale 4	1.9	1.9	5.5	03/15/97 - 03/24/97	
Lauderdale 5	1.8	1.8	8.8	11/02/96 - 11/17/96	
Fort Myers 1	1.4	1.4	30.8	11/02/96 - 12/27/96	
Fort Myers 2	2.2	3.6	0.0	NONE	
Manatee 1	3.0	2.6	0.0	NONE	
Manatee 2	2.0	3.6	0.0	NONE	
Martin 1	11.5	8.9	0.0	NONE	
Martin 2	6.1	7.2	0.0	NONE	
Martin 3	2.0	2.0	1.4	(10/01/96) - 10/05/96	**
Martin 4	3.5	8.0	3.3	02/15/97 - 02/26/97	**
Port Everglades 1	2.0	2.0	0.0	NONE	
Port Everglades 2	2.2	2.0	0.0	NONE	
Port Everglades 3	2.0	3.1	0.0	NONE	
Port Everglades 4	3.6	2.8	17.0	03/01/97 - (03/31/97)	
Putnam 1	4.1	2.2	11.0	11/16/95 - 12/13/95 03/15/97 - 03/26/97	** **
Putnam 2	1.8	2.6	9.3	03/15/97 - (03/31/97)	**
Riviera 3	2.0	2.0	0.0	NONE	
Riviera 4	3.1	2.6	0.0	NONE	
Sanford 3	2.9	2.0	0.0	NONE	
Sanford 4	2.0	2.0	0.0	NONE	
Sanford 5	2.0	2.8	0.0	NONE	
Turkey Point 1	1.8	1.8	11.0	10/26/96 - 11/14/96	
Turkey Point 2	2.0	3.7	0.0	NONE	
Turkey Point 3	2.8	2.8	13.2	03/08/97 - (03/31/97)	
Turkey Point 4	3.2	3.2	0.0	NONE	
St.Lucie 1	21.8	3.2	0.0	NONE	
St.Lucie 2	3.8	3.2	16.5	03/01/97 - 03/30/97	
SJRPP 1	12.7	1.7	0.0	NONE	
SJRPP 2	2.0	2.0	0.0	NONE	
Scherer 4	4.3	2.0	0.0	NONE	

* Note: Overhaul dates shown in parentheses begin before or end after the projected period.

** Note: Partial Planned Outage.

APPENDIX II
FUEL COST RECOVERY
PROJECTED PERIOD

BTB - 3
DOCKET NO 960001-EI
FPL WITNESS:B.T.BIRKETT
EXHIBIT ____________
PAGES 1-40
JUNE 24, 1996

APPENDIX II
FUEL COST RECOVERY
PROJECTED PERIOD

TABLE OF CONTENTS

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SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: OCTOBER 1996 - MARCH 1997

		(a) DOLLARS	(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$469,497,540	30,317,375	1.5486
2	Nuclear Fuel Disposal Costs (E2)	10,952,424	11,838,090	0.0925
3	Fuel Related Transactions (E2)	10,919,978	0	0.0000
4	Fuel Cost of Sales to FKEC / CKW	(9,852,205)	(457,194)	2.1549
5	TOTAL COST OF GENERATED POWER	$481,517,737	29,860,181	1.6126
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	61,297,950	3,970,720	1.5437
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)	26,724,990	1,481,431	1.8040
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)	10,461,930	482,228	2.1695
9	Energy Cost of Sched E Economy Purch (E9)	0	0	0.0000
10	Capacity Cost of Sched E Economy Purchases	0	0	0.0000
11	Mission Settlement	5,220,180		
12	Payments to Qualifying Facilities (E8)	56,346,004	2,968,817	1.8979
13	TOTAL COST OF PURCHASED POWER	$160,051,054	8,903,196	1.7977
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)		38,763,377	
15	Fuel Cost of Economy Sales (E6)	(8,163,695)	(301,734)	2.7056
16	Gain on Economy Sales (E6A)	(1,343,394)	(301,734)	0.4452
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,007,000)	(261,225)	0.3855
18	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($10,514,089)	(562,959)	1.8676
19a	Net Inadvertent Interchange	0	0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	$631,054,702	38,200,418	1.6520
21	Net Unbilled Sales	(21,171,129) **	(1,281,578)	(0.4688)
22	Company Use	1,893,164 **	114,601	0.0051
23	T & D Losses	41,018,556 **	2,483,027	0.1112
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$631,054,702	36,884,368	1.7109
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$2,017,545	117,922	1.7109
26	Jurisdictional MWH Sales	$629,037,157	36,766,446	1.7109
27	Jurisdictional Loss Multiplier	-	-	1.00071
28	Jurisdictional MWH Sales Adjusted for Line Losses	$629,483,773	36,766,446	1.7121
29	FINAL TRUE-UP OCT 95 - MAR 96 $17,157,052 underrecovery; EST/ACT TRUE-UP APRIL 96 - SEPT 96 $88,480,000 underrecovery	105,637,052	36,766,446	0.2873
30	TOTAL JURISDICTIONAL FUEL COST	$735,120,825	36,766,446	1.9994
31	Revenue Tax Factor			1.01609
32	Fuel Factor Adjusted for Taxes			2.0316
33	GPIF *** reward	$1,980,538	36,766,446	0.0054
34	Fuel Factor including GPIF (Line 31 + Line 32)			2.0370
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			2.037

** For Informational Purposes Only
*** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E - 1A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: OCTOBER 1996 THROUGH MARCH 1997

1. Estimated over/(under) recovery (2 months actual, 4 months estimated period) (Schedule E1-B)	$ (88,480,000)
2. Final True-Up (6 months actual period)	$ (17,157,052)
3.Total over/(under) recovery (Lines 1 + 2) To be included in 6 month projected period (Schedule E1, Line 28)	$ (105,637,052)
2. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	36,766,446
3. True-Up Factor (Lines 3/4) c/kWh:	(0.2873)

CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1996

SCHEDULE E-1b
Page 1 / 1

LINE NO		(1) ACTUAL APRIL	(2) ACTUAL MAY	(3) ESTIMATED JUNE	(4) ESTIMATED JULY	(5) ESTIMATED AUGUST	(6) ESTIMATED SEPTEMBER	(7) TOTAL PERIOD
A	Fuel Costs & Net Power Transactions							
1 a	Fuel Cost of System Net Generation	$ 96,121,431	$ 120,306,461	$ 110,635,180	$ 124,671,560	$ 128,230,970	$ 112,502,280	$ 692,467,883
b	Nuclear Fuel Disposal Costs	1,729,146	1,573,659	1,893,273	1,832,201	1,893,273	1,893,273	10,815,024
c	Coal Cars Depreciation & Return	418,841	416,961	415,081	413,201	411,320	409,440	2,484,844
d	Gas Pipelines Depreciation & Return	309,871	308,302	306,733	305,164	303,595	302,026	1,835,691
e	DOE D&D Fund Payment	0	0	0	0	0	0	0
2	Fuel Cost of Power Sold	(2,346,431)	(6,351,572)	(1,697,454)	(9,196,051)	(5,947,264)	(1,854,086)	(27,392,858)
3 a	Fuel Cost of Purchased Power	11,215,078	13,039,436	12,556,420	11,635,850	10,238,100	11,006,710	71,691,594
b	Energy Payments to Qualifying Facilities	8,688,063	11,452,836	9,921,627	10,962,503	10,992,876	9,266,743	61,284,648
4	Energy Cost of Economy Purchases	3,852,915	3,643,369	6,963,780	7,862,040	9,982,330	9,712,240	42,016,674
5	Total Fuel Costs & Net Power Transactions	$ 119,989,114	$ 144,189,151	$ 140,994,640	$ 148,486,468	$ 156,105,200	$ 145,238,626	$ 855,003,500
6	Adjustments to Fuel Cost							
a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(1,836,997)	(1,822,059)	$ (1,644,489)	$ (1,644,489)	$ (1,644,489)	$ (1,644,489)	$ (10,237,010)
b	Inventory Adjustments	(6,000)	24,198	0	0	0	0	18,198
c	Non Recoverable Oil/Tank Bottoms	123,725	(16,285)	0	0	0	0	107,440
d	Modifications to Generating Units	0	0	0	0	0	0	0
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 118,269,842	$ 142,375,305	$ 139,350,151	$ 146,841,979	$ 154,460,711	$ 143,594,137	$ 844,892,127
B	kWh Sales							
1	Jurisdictional kWh Sales (RTP @ CBL) (a)	5,425,135,569	5,928,331,567	6,762,721,000	7,475,640,000	7,450,237,000	7,255,755,000	40,297,820,136
2	Sale for Resale (excluding FKEC & CKW)	29,523,644	14,575,387	36,116,271	36,116,271	36,116,271	36,116,271	188,564,116
3	Sub-Total Sales (excluding FKEC & CKW)	5,454,659,213	5,942,906,954	6,798,837,271	7,511,756,271	7,486,353,271	7,291,871,271	40,486,384,252
6	Jurisdictional % of Total kWh Sales (lines B1/B3)	99.45874 %	99.75474 %	99.46879 %	99.51920 %	99.51757 %	99.50471 %	99.53425 %
C	True-up Calculation							
1	Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 108,637,905	$ 120,749,205	$ 146,490,787	$ 161,933,693	$ 161,383,426	$ 157,170,651	$ 856,365,666
2	Fuel Adjustment Revenues Not Applicable to Period							
a	Prior Period True-up Provision	(16,280,671)	(16,280,671)	(16,280,671)	(16,280,671)	(16,280,671)	(16,280,671)	(97,684,026)
b	GPIF, Net of Revenue Taxes (b)	(354,150)	(354,150)	(354,150)	(354,150)	(354,150)	(354,150)	(2,124,901)
c	Oil Backout Revenues, Net of revenue Taxes	1,304	491					1,795
3	Jurisdictional Fuel Revenues Applicable to Period	$ 92,004,387	$ 104,114,875	$ 129,855,966	$ 145,298,872	$ 144,748,604	$ 140,535,829	$ 756,558,533
4 a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 118,269,842	$ 142,375,305	$ 139,350,151	$ 146,841,979	$ 154,460,711	$ 143,594,137	$ 844,892,127
b	Nuclear Fuel Expense - 100% Retail	24,417	25,280	0	0	0	0	49,697
c	RTP Incremental Fuel -100% Retail	17,836	(8,322)	0	0	0	0	9,513
d	D&D Fund Payments -100% Retail	0	0	0	0	0	0	0
e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	118,227,590	142,358,347	139,350,152	146,841,980	154,460,712	143,594,137	844,832,918
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.45874 %	99.75474 %	99.46879 %	99.51920 %	99.51757 %	99.50471 %	99.53425 %
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00070) +(Lines C4b,c,d)	$ 117,712,235	$ 142,125,564	$ 138,706,937	$ 146,238,259	$ 153,823,148	$ 142,982,948	$ 841,589,091
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (25,707,848)	$ (38,010,689)	$ (8,850,971)	$ (939,387)	$ (9,074,544)	$ (2,447,119)	$ (85,030,558)
8	Interest Provision for the Month (Line D10)	(542,981)	(610,543)	(645,466)	(597,136)	(549,092)	(504,223)	(3,449,442)
9	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(97,684,026)	(107,654,184)	(129,994,745)	(123,210,513)	(108,466,365)	(101,809,330)	(97,684,026)
a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(17,157,052)	(17,157,052)	(17,157,052)	(17,157,052)	(17,157,052)	(17,157,052)	(17,157,052)
10	Prior Period True-up Collected/(Refunded) This Period	16,280,671	16,280,671	16,280,671	16,280,671	16,280,671	16,280,671	97,684,026
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (124,811,236)	$ (147,151,797)	$ (140,367,565)	$ (125,623,417)	$ (118,966,382)	$ (105,637,052)	$ (105,637,052)

NOTES
(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded.
(b) Generation Performance Incentive Factor Reward (Per Order No. PSC-96-0353-FOF-EI) of $2,159,086 / 6 Mos. x 98.4167% Revenue Tax Factor = $354,150.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL VARIANCE
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1996

NE O.			(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1	a	Fuel Cost of System Net Generation	$ 692,467,883	$ 564,837,790	$ 127,630,093	22.6 %
	b	Nuclear Fuel Disposal Costs	10,615,024	9,868,296	746,728	7.6 %
	c	Coal Cars Depreciation & Return	2,484,844	2,593,692	(108,848)	(4.2) %
	d	Gas Pipelines Depreciation & Return	1,835,691	1,830,741	4,950	0.3 %
	e	DOE Decontamination &Decommissioning Fund Payment	0	0	0	N/A
2		Fuel Cost of Power Sold	(27,392,858)	(18,849,433)	(8,543,425)	45.3 %
3	a	Fuel Cost of Purchased Power	71,691,594	92,551,680	(20,860,086)	(22.5) %
	b	Energy Payments to Qualifying Facilities	61,284,648	56,153,965	5,130,683	9.1 %
4		Energy Cost of Economy Purchases	42,016,674	37,880,270	4,136,404	10.9 %
5		Total Fuel Costs & Net Power Transactions	$ 855,003,500	$ 746,867,001	$ 108,136,499	14.5 %
6		Adjustments to Fuel Cost				
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (10,237,010)	$ (10,059,440)	$ (177,570)	1.8 %
	b	Inventory Adjustments	18,198	0	18,198	N/A
	c	Non Recoverable Oil/Tank Bottoms	107,440	0	107,440	N/A
	d	Modifications to Generating Units	0	0	0	N/A
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 844,892,127	$ 736,807,561	$ 108,084,566	14.7 %
1		Jurisdictional kWh Sales	40,297,820,136	40,889,121,000	(591,300,864)	(1.4) %
2		Sale for Resale	188,564,116	210,105,000	(21,540,884)	(10.3) %
3		Total Sales (Excluding RTP Incremental)	40,486,384,252	41,099,226,000	(612,841,748)	(1.5) %
4		Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
1		Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$ 856,365,666	$ 831,238,082	$ 25,127,584	3.0 %
	a	Prior Period True-up Provision	(97,684,026)	(97,684,026)	0	0.0 %
	b	Generation Performance Incentive Factor Net (b)	(2,124,901)	(2,124,901)	0	0.0 %
	c	Oil Backout Revenues, Net of revenue Taxes	1,795	0	1,795	N/A
3		Jurisdictional Fuel Revenues Applicable to Period	$ 756,558,533	$ 731,429,155	$ 25,129,378	3.4 %
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 844,892,127	$ 736,807,561	$ 108,084,566	14.7 %
	b	Nuclear Fuel Expense - 100% Retail	49,697	0	49,697	N/A
	c	RTP Incremental Fuel -100% Retail	9,513	0	9,513	N/A
	d	D&D Fund Payments -100% Retail (Line A 1 e)	0	0	0	N/A
	e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	844,832,918	736,807,561	108,025,357	14.7 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 841,589,091	$ 731,429,155	$ 110,159,936	15.1 %
7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ (85,030,558)	$ (0)	$ (85,030,558)	N/A
8		Interest Provision for the Month	(3,449,442)	-	(3,449,442)	N/A
9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(97,684,026)	(97,684,026)	0	0.0 %
	a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(17,157,052)	0	(17,157,052)	N/A
10		Prior Period True-up Collected/(Refunded) This Period	97,684,026	97,684,026	0	0.0 %
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ (105,637,052)	$ (0)	$ (105,637,052)	N/A

(a) Per Schedule E-2, filed January 22, 1996.

(b) Generation Performance Incentive Factor Reward (Per Order No. PSC-96-0353-FOF-EI) of $2,159,086 / 6 Mos. x 98.4167% Revenue Tax Factor = $354,150.

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE - UP FACTOR FLORIDA POWER AND LIGHT COMPANY FOR THE PERIOD: OCTOBER 1996 THROUGH MARCH 1997

1. TOTAL AMOUNT OF ADJUSTMENTS:	$ 107,617,590
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$ 1,980,538
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 105,637,052
2. TOTAL JURISDICTIONAL SALES (MWH)	36,766,446
3. ADJUSTMENT FACTORS c/kWh:	0.2927
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0054
B. TRUE-UP FACTOR	0.2873

SCHEDULE E - 1D

FLORIDA POWER & LIGHT COMPANY

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

OCTOBER 1996 - MARCH 1997

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	28.00	30.20
OFF PEAK	72.00	69.80
	100.00	100.00

FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$631,054,702	$190,578,520	$440,476,182
2 MWH SALES	36,884,367	10,327,623	26,556,744
3 COST PER KWH SOLD	1.7109	1.8453	1.6586
4 JURISDICTIONAL LOSS FACTOR	1.00071	1.00071	1.00071
5 JURISDICTIONAL FUEL FACTOR	1.7121	1.8466	1.6598
6 TRUE-UP	0.2873	0.2873	0.2873
7			
8 TOTAL	1.9994	2.1339	1.9471
9 REVENUE TAX FACTOR	1.01609	1.01609	1.01609
10 RECOVERY FACTOR	2.0316	2.1682	1.9784
11 GPIF	0.0054	0.0054	0.0054
12 RECOVERY FACTOR including GPIF	2.0370	2.1736	1.9838
13 RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	2.037	2.174	1.984

HOURS:		
	ON-PEAK	23.30 %
	OFF-PEAK	76.70 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

OCTOBER 1996 - MARCH 1997

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		2.037	1.00201	2.041
A-1*	SL-1, OL-1		2.014	1.00201	2.018
B	GSD-1		2.037	1.00200	2.041
C	GSLD-1 & CS-1		2.037	1.00173	2.041
D	GSLD-2, CS-2, OS-2 & MET		2.037	0.99640	2.030
E	GSLD-3 & CS-3		2.037	0.96159	1.959
A	RST-1, GST-1	ON-PEAK	2.174	1.00201	2.178
		OFF-PEAK	1.984	1.00201	1.988
B	GSDT-1	ON-PEAK	2.174	1.00200	2.178
	CILC-1(G)	OFF-PEAK	1.984	1.00200	1.988
C	GSLDT-1 &	ON-PEAK	2.174	1.00173	2.177
	CST-1	OFF-PEAK	1.984	1.00173	1.987
D	GSLDT-2 &	ON-PEAK	2.174	0.99640	2.166
	CST-2	OFF-PEAK	1.984	0.99640	1.977
E	GSLDT-3,CST-3,	ON-PEAK	2.174	0.96159	2.090
	CILC -1(T) & ISST-1(T)	OFF-PEAK	1.984	0.96159	1.908
F	CILC -1(D) &	ON-PEAK	2.174	0.99814	2.170
	ISST-1(D)	OFF-PEAK	1.984	0.99814	1.980

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

Florida Power & Light Company
1995 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1 Sec	40,922,712	1.067486100	43,684,426	0.936780	2,761,714	1.00201
3	GS-1 Sec	4,824,449	1.067486100	5,150,032	0.936780	325,583	1.00201
5	GSD-1 Pri	4,805	1.044406598	5,018	0.957482	213	
6	GSD-1 Sec	17,545,079	1.067486100	18,729,128	0.936780	1,184,049	
7	Subtot GSD-1	17,549,884	1.067479781	18,734,146	0.936788	1,184,262	1.00200
9	OS-2 Pri	20,311	1.044406598	21,213	0.957482	902	0.98034
11	GSLD-1 Pri	85,532	1.044406598	89,330	0.957482	3,798	
12	GSLD-1 Sec	6,828,177	1.067486100	7,288,984	0.936780	460,807	
13	Subtot GSLD-1	6,913,709	1.067200576	7,378,314	0.937031	464,605	1.00174
15	CS-1 Pri	3,916	1.044406598	4,089	0.957482	174	
16	CS-1 Sec	207,250	1.067486100	221,237	0.936780	13,986	
17	Subtot CS-1	211,165	1.067058187	225,326	0.937156	14,160	1.00160
19	Subtot GSLD1 / CS1	7,124,874	1.067198350	7,603,640	0.937035	478,766	1.00173
21	GSLD-2 Pri	322,094	1.044406598	336,397	0.957482	14,303	
22	GSLD-2 Sec	1,111,393	1.067486100	1,186,397	0.936780	75,004	
23	Subt GSLDT-2	1,433,487	1.062300328	1,522,794	0.941353	89,307	0.99714
25	CS-2 Pri	3,851	1.044406598	4,022	0.957482	171	
26	CS-2 Sec	120,332	1.067486100	128,453	0.936780	8,121	
27	Subtot CST-2	124,183	1.066770378	132,475	0.937409	8,292	1.00133
29	Subtot GSLD2 / CS2	1,557,670	1.062008678	1,655,269	0.941038	97,598	0.99747
31	GSLD-3 Trn	741,566	1.024433539	759,685	0.976149	18,119	0.96159
33	CS-3 Trn	0	1.024433539	0	0.000000	0	0.00000
35	Subtot GSLD3 / CS3	741,566	1.024433539	759,685	0.976149	18,119	0.96159
37	ISST-1 Sec	2,242	1.067486100	2,393	0.936780	151	1.00201
39	SST-1 Pri	43,631	1.044406598	45,568	0.957482	1,936	
40	SST-1 Sec	25,275	1.067486100	26,981	0.936780	1,706	
41	SST-1 (D)	68,906	1.052872337	72,550	0.949783	3,643	0.98129
43	SST-1 Trn	99,883	1.024433539	102,323	0.976149	2,440	0.96159
45	CILC D Pri	416,869	1.044406598	435,381	0.957482	18,512	
46	CILC D Sec	1,917,315	1.067486100	2,046,707	0.936780	129,392	
47	CILC D	2,334,184	1.063384259	2,482,088	0.940412	147,904	0.99814
49	CILC G Sec	144,000	1.067486100	153,718	0.936780	9,718	1.00201
51	Subtot CILC D / CILC G	2,478,184	1.063603766	2,635,806	0.940200	157,622	0.99836
53	CILC T Trn	1,094,627	1.024433539	1,121,373	0.976149	26,746	0.96159
55	ISST-D & CILC-D	2,338,426	1.063368214	2,484,481	0.940408	146,055	0.99814
57	GSD-1 & CILC-1(G)	17,693,883	1.067479833	18,887,864	0.936788	1,193,980	1.00200
59	MET Pri	84,097	1.044406598	87,831	0.957482	3,734	0.98034
61	OS-2, GSLD2, CS2, & MET	1,662,079	1.061510246	1,764,314	0.942064	102,235	0.99640
63	OL-1 Sec	104,255	1.067486100	111,291	0.936780	7,036	1.00201
65	SL-1 Sec	320,765	1.067486100	342,412	0.936780	21,647	1.00201
67	Subtot OL1 / SL1	425,020	1.067486100	453,703	0.936780	28,683	1.00201
69	SL-2 Sec	70,967	1.067486100	75,756	0.936780	4,789	1.00201
71	Total FPSC	77,065,393	1.066109493	82,160,147	0.937990	5,094,754	1.00071
73	Total FERC Sales	1,450,416	1.024691373	1,486,229	0.975904	35,813	
75	Total Company	78,515,809	1.065344380	83,646,376	0.938664	5,130,567	
77	Company Use	184,661	1.067486100	197,123	0.936780	12,462	
79	Total FPL	78,700,470	1.065349405	83,843,499	0.938659	5,143,029	1.00000
81	Summary of Sales by Voltage						
83	Transmission	3,367,768	1.024433539	3,450,055	0.976149	82,266	
85	Primary	1,003,829	1.044406598	1,048,406	0.957482	44,577	
87	Secondary	74,144,212	1.067486100	79,147,915	0.936780	5,003,704	
89	Total	78,515,809	1.065344380	83,646,376	0.938664	5,130,567	

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD OCTOBER 1996 - MARCH 1997

SCHEDULE E2

LINE NO.		(a) OCTOBER	(b) NOVEMBER	(c) ESTIMATED DECEMBER	(d) JANUARY	(e) FEBRUARY	(f) MARCH	(g) TOTAL PERIOD	LINE NO
A1	FUEL COST OF SYSTEM GENERATION	$89,297,380	$82,601,360	$76,287,770	$73,247,390	$68,924,670	$79,138,970	$469,497,540	A1
1a	NUCLEAR FUEL DISPOSAL	1,833,678	1,939,104	1,876,048	1,936,501	1,749,097	1,617,996	10,952,424	1a
1b	COAL CAR INVESTMENT	407,560	405,680	403,799	401,919	400,039	398,159	2,417,156	1b
1c	NUCLEAR THERMAL UPRATE	0	0	0	458,282	504,783	500,555	1,463,620	1c
1d	GAS LATERAL ENHANCEMENTS	300,457	298,887	297,318	295,749	294,180	292,611	1,779,202	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	5,260,000	0	0	0	0	5,260,000	1e
2	FUEL COST OF POWER SOLD	(2,140,421)	(1,954,920)	(1,893,757)	(1,297,841)	(1,602,359)	(1,624,790)	(10,514,089)	2
3	FUEL COST OF PURCHASED POWER	11,418,990	11,325,460	11,830,890	8,184,670	8,654,520	9,883,420	61,297,950	3
3a	MISSION SETTLEMENT	870,030	870,030	870,030	870,030	870,030	870,030	5,220,180	3a
3b	QUALIFYING FACILITIES	12,311,614	9,167,292	9,768,527	9,454,222	8,231,852	7,412,497	56,346,004	3b
4	ENERGY COST OF ECONOMY PURCHASES	11,794,040	4,311,450	4,200,160	7,956,500	4,996,120	3,928,650	37,186,920	4
4a	FUEL COST OF SALES TO FKEC / CKW	(1,923,558)	(1,878,988)	(1,731,240)	(1,536,184)	(1,366,780)	(1,415,455)	(9,852,205)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$124,169,770	$112,345,355	$101,909,545	$99,971,238	$91,656,152	$101,002,643	$631,054,702	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	6,821,925	6,383,906	6,168,327	5,912,524	5,813,873	5,783,812	36,884,367	6
7	COST PER KWH SOLD (¢/KWH)	1.8202	1.7598	1.6521	1.6908	1.5765	1.7463	1.7109	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00071	1.00071	1.00071	1.00071	1.00071	1.00071	1.00071	7a
7b	JURISDICTIONAL COST (¢/KWH)	1.8214	1.7611	1.6533	1.6920	1.5776	1.7475	1.7121	7b
9	TRUE-UP (¢/KWH)	0.2598	0.2765	0.2859	0.2984	0.3037	0.3054	0.2873	9
10	TOTAL	2.0812	2.0376	1.9392	1.9904	1.8813	2.0529	1.9994	10
11	REVENUE TAX FACTOR 0.01609	0.0335	0.0328	0.0312	0.0320	0.0303	0.0330	0.0322	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	2.1147	2.0704	1.9704	2.0224	1.9116	2.0859	2.0316	12
13	GPIF (¢/KWH)	0.0049	0.0052	0.0054	0.0056	0.0057	0.0057	0.0054	13
14	RECOVERY FACTOR including GPIF	2.1196	2.0756	1.9758	2.0280	1.9173	2.0916	2.0370	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	2.120	2.076	1.976	2.028	1.917	2.092	2.037	15

Generating System Comparative Data by Fuel Type

	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Total
Fuel Cost of System Net Generation ($)							
1 Heavy Oil	$33,236,060	$21,218,320	$15,197,870	$15,714,790	$8,710,710	$13,391,770	$107,469,520
2 Light Oil	$11,420	$0	$0	$11,970	$0	$0	$23,390
3 Coal	$2,584,140	$9,833,810	$9,198,430	$7,880,410	$8,669,930	$9,091,210	$47,257,930
4 Gas	$45,886,110	$43,694,610	$44,265,300	$41,837,140	$44,500,020	$50,018,040	$270,201,220
5 Nuclear	$7,579,650	$7,854,620	$7,626,170	$7,803,080	$7,044,010	$6,637,950	$44,545,480
6 Orimulsion	$0	$0	$0	$0	$0	$0	$0
7 *Total*	$89,297,380	$82,601,360	$76,287,770	$73,247,390	$68,924,670	$79,138,970	$469,497,540
System Net Generation (MWH)							
8 Heavy Oil	1,251,177	815,464	596,993	627,335	358,976	553,362	4,203,307
9 Light Oil	183	0	0	192	0	0	375
10 Coal	167,044	567,410	536,784	464,763	508,058	524,986	2,769,045
11 Gas	1,784,431	1,778,560	1,693,406	1,759,215	2,014,415	2,476,531	11,506,558
12 Nuclear	1,968,945	2,082,148	2,019,298	2,104,452	1,900,795	1,762,452	11,838,090
13 Orimulsion	0	0	0	0	0	0	0
14 *Total*	5,171,780	5,243,582	4,846,481	4,955,957	4,782,244	5,317,331	30,317,375
Units of Fuel Burned							
15 Heavy Oil (BBLS)	1,885,681	1,211,697	899,691	948,891	535,928	827,941	6,309,829
16 Light Oil (BBLS)	410	0	0	430	0	0	840
17 Coal (TONS)	64,700	302,928	286,390	242,107	270,570	292,667	1,459,362
18 Gas (MCF)	15,039,036	14,232,614	13,563,542	14,141,549	16,908,812	21,201,812	95,087,365
19 Nuclear (MBTU)	21,474,262	22,247,686	21,578,300	22,497,150	20,320,006	18,841,988	126,959,392
20 Orimulsion (BBLS)	0	0	0	0	0	0	0
BTU Burned (MMBTU)							
21 Heavy Oil	12,068,362	7,754,858	5,758,022	6,072,900	3,429,936	5,298,823	40,382,900
22 Light Oil	2,392	0	0	2,508	0	0	4,900
23 Coal	1,577,384	5,690,633	5,387,329	4,638,412	5,086,770	5,305,112	27,685,639
24 Gas	15,039,036	14,232,614	13,563,542	14,141,549	16,908,812	21,201,812	95,087,365
25 Nuclear	21,474,262	22,247,686	21,578,300	22,497,150	20,320,006	18,841,988	126,959,392
26 Orimulsion	0	0	0	0	0	0	0
27 *Total*	50,161,435	49,925,791	46,287,193	47,352,519	45,745,524	50,647,735	290,120,196

Florida Power & Light Company
6/12/96

Generating System Comparative Data by Fuel Type

	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Total
Generation Mix (%MWH)							
28 Heavy Oil	24.19%	15.55%	12.32%	12.66%	7.51%	10.41%	13.86%
29 Light Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30 Coal	3.23%	10.82%	11.08%	9.38%	10.62%	9.87%	9.13%
31 Gas	34.50%	33.92%	34.94%	35.50%	42.12%	46.57%	37.95%
32 Nuclear	38.07%	39.71%	41.67%	42.46%	39.75%	33.15%	39.05%
33 Orimulsion	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34 ***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Cost per Unit							
35 Heavy Oil ($/BBL)	17.6255	17.5112	16.8923	16.5612	16.2535	16.1748	17.0321
36 Light Oil ($/BBL)	27.8537	0.0000	0.0000	27.8372	0.0000	0.0000	27.8452
37 Coal ($/ton)	39.9403	32.4625	32.1185	32.5493	32.0432	31.0633	32.3826
38 Gas ($/MCF)	3.0511	3.0700	3.2636	2.9585	2.6318	2.3591	2.8416
39 Nuclear ($/MBTU)	0.3530	0.3531	0.3534	0.3468	0.3467	0.3523	0.3509
40 Orimulsion ($/BBL)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Fuel Cost per MMBTU ($/MMBTU)							
41 Heavy Oil	2.7540	2.7361	2.6394	2.5877	2.5396	2.5273	2.6613
42 Light Oil	4.7748	0.0000	0.0000	4.7722	0.0000	0.0000	4.7735
43 Coal	1.6382	1.7281	1.7074	1.6989	1.7044	1.7137	1.7069
44 Gas	3.0511	3.0700	3.2636	2.9585	2.6318	2.3591	2.8416
45 Nuclear	0.3530	0.3531	0.3534	0.3468	0.3467	0.3523	0.3509
46 Orimulsion	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
BTU burned per KWH (BTU/KWH)							
46 Heavy Oil	9,646	9,510	9,645	9,680	9,555	9,576	9,607
47 Light Oil	13,069	0	0	13,064	0	0	13,067
48 Coal	9,443	10,029	10,036	9,980	10,012	10,105	9,998
49 Gas	8,428	8,002	8,010	8,039	8,394	8,561	8,264
50 Nuclear	10,906	10,685	10,686	10,690	10,690	10,691	10,725
51 Orimulsion	0	0	0	0	0	0	0
Generated Fuel Cost per KWH (cents/KWH)							
52 Heavy Oil	2.6564	2.6020	2.5457	2.5050	2.4265	2.4201	2.5568
53 Light Oil	6.2404	0.0000	0.0000	6.2344	0.0000	0.0000	6.2373
54 Coal	1.5470	1.7331	1.7136	1.6956	1.7065	1.7317	1.7067
55 Gas	2.5715	2.4567	2.6140	2.3782	2.2091	2.0197	2.3482
56 Nuclear	0.3850	0.3772	0.3777	0.3708	0.3706	0.3766	0.3763
57 Orimulsion	0	0	0	0	0	0	0
58 ***Total***	1.7266	1.5753	1.5741	1.4780	1.4413	1.4883	1.5486

Estimated For The Period of : Oct-96

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	406	121,976	42.7	77.4	75.7	9,625	Heavy Oil BBLS ->	181,832	6,400,002	1,163,726	3,226,017	2.6448
2			1,814					Gas MCF ->	27,769	1,000,000	27,769	55,890	3.0814
3													
4	TRKY O 2	403	127,257	45.0	94.3	75.5	9,558	Heavy Oil BBLS ->	188,356	6,400,000	1,205,477	3,341,759	2.6260
5			2,323					Gas MCF ->	33,026	1,000,000	33,026	66,544	2.8643
6													
7	TRKY N 3	688	453,055	94.4	94.2	96.9	11,007	Nuclear MBTU ->	4,986,878	1,000,000	4,986,878	1,618,907	0.3573
8													
9	TRKY N 4	688	453,055	94.4	95.0	96.9	11,007	Nuclear MBTU ->	4,986,878	1,000,000	4,986,878	1,592,310	0.3515
10													
11	FT LAUD4	452	297,509	95.9	96.0	95.2	7,782	Gas MCF ->	2,315,322	1,000,000	2,315,322	4,579,256	1.5392
12													
13	FT LAUD5	452	126,586	40.7	96.0	95.3	7,780	Gas MCF ->	984,899	1,000,000	984,899	1,951,642	1.5417
14													
15	PT EVER1	212	38,220	25.2	96.0	78.2	10,241	Heavy Oil BBLS ->	60,346	6,399,999	386,216	1,064,947	2.7863
16			3					Gas MCF ->	5,246	1,000,000	5,246	10,369	314.2121
17													
18	PT EVER2	213	43,758	28.7	95.8	73.8	10,222	Heavy Oil BBLS ->	68,899	6,400,001	440,954	1,215,883	2.7786
19			10					Gas MCF ->	6,430	1,000,000	6,430	12,710	133.7895
20													
21	PT EVER3	391	194,104	75.4	94.9	82.0	9,531	Heavy Oil BBLS ->	287,352	6,400,001	1,839,052	5,070,985	2.6125
22			17,104					Gas MCF ->	173,974	1,000,000	173,974	346,055	2.0232
23													
24	PT EVER4	387	180,150	67.4	92.2	76.9	9,550	Heavy Oil BBLS ->	267,698	6,400,000	1,713,264	4,724,137	2.6223
25			6,840					Gas MCF ->	72,493	1,000,000	72,493	145,206	2.1229
26													
27	RIV 3	292	89,280	42.7	96.0	77.2	10,568	Gas MCF ->	943,476	1,000,000	943,476	1,864,536	2.0884
28													
29	RIV 4	292	2,852	42.0	94.3	76.8	10,608	Heavy Oil BBLS ->	4,392	6,399,982	28,107	76,386	2.6781
30			84,855					Gas MCF ->	902,268	1,000,000	902,268	1,783,101	2.1013
31													

Date: 5/23/96
Company: Florida Power & Light

Schedule E4
Page: 2

Estimated For The Period of : Oct-96

Line	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUC 1	853	574,195	95.0	95.0	98.4	10,821	Nuclear	MBTU ->	6,213,134	1,000,000	6,213,134	2,262,823	0.3941
33														
34	ST LUC 2	726	488,640	95.0	95.0	98.4	10,821	Nuclear	MBTU ->	5,287,373	1,000,000	5,287,373	2,105,608	0.4309
35														
36	CAP CN 1	405	19,945	62.0	93.5	72.5	9,814	Heavy Oil	BBLS ->	29,143	6,400,000	186,515	531,438	2.6645
37			159,618					Gas	MCF ->	1,575,698	1,000,000	1,575,698	3,115,207	1.9517
38														
39	CAP CN 2	403	89,640	60.9	92.7	75.3	9,724	Heavy Oil	BBLS ->	132,315	6,399,998	846,814	2,412,827	2.6917
40			85,720					Gas	MCF ->	858,377	1,000,000	858,377	1,697,540	1.9803
41														
42	SANFRD 3	147	1,230	1.2	95.1	74.7	10,403	Heavy Oil	BBLS ->	1,951	6,399,836	12,485	33,643	2.7359
43			0					Gas	MCF ->	308	1,000,000	308	613	
44														
45	SANFRD 4	394	60,955	21.7	96.0	73.1	9,924	Heavy Oil	BBLS ->	93,792	6,400,002	600,266	1,617,538	2.6537
46			59					Gas	MCF ->	5,248	1,000,000	5,248	10,405	17.6058
47														
48	SANFRD 5	394	108,557	41.1	95.2	75.2	9,892	Heavy Oil	BBLS ->	165,939	6,399,998	1,062,008	2,861,797	2.6362
49			6,846					Gas	MCF ->	79,536	1,000,000	79,536	157,940	2.3070
50														
51	PUTNAM 1	262	149,968	86.9	92.4	91.0	8,314	Gas	MCF ->	1,246,828	1,000,000	1,246,828	2,465,612	1.6441
52														
53	PUTNAM 2	262	129,001	74.7	95.3	90.8	8,325	Gas	MCF ->	1,073,918	1,000,000	1,073,918	2,123,729	1.6463
54														
55	MANATE 1	805	74,746	13.0	94.4	52.6	10,102	Heavy Oil	BBLS ->	117,984	6,400,002	755,099	2,090,774	2.7972
56														
57	MANATE 2	805	139,594	24.3	94.4	69.1	9,825	Heavy Oil	BBLS ->	214,303	6,399,999	1,371,540	3,797,623	2.7205
58														
59	FT MY 1	144		0.0	96.0		0							
60														
61	FT MY 2	394	46,429	16.5	12.2	87.2	9,466	Heavy Oil	BBLS ->	68,671	6,400,001	439,492	1,119,211	2.4106
62														

Date: 5/23/96
Company: Florida Power & Light

Schedule E4
Page: 3

Estimated For The Period of : Oct-96

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	CUTLER 5	72	57	0.1	96.0	84.9	11,784	Gas MCF ->	668	1,000,000	668	1,321	2.3339
64													
65	CUTLER 6	145	155	0.1	94.6	77.2	11,448	Gas MCF ->	1,779	1,000,000	1,779	3,520	2.2651
66													
67	MARTIN 1	821	107	1.8	79.6	35.6	11,086	Heavy Oil BBLS ->	169	6,398,220	1,078	3,176	2.9682
68			10,239					Gas MCF ->	113,619	1,000,000	113,619	309,073	3.0185
69													
70	MARTIN 2	805	1,657	6.5	86.7	46.4	10,435	Heavy Oil BBLS ->	2,542	6,399,882	16,269	47,919	2.8912
71			36,088					Gas MCF ->	377,598	1,000,000	377,598	1,023,913	2.8373
72													
73	MARTIN 3	460	300,861	97.0	95.9	93.7	7,292	Gas MCF ->	2,193,919	1,000,000	2,193,919	4,339,162	1.4422
74													
75	MARTIN 4	460	279,486	90.0	88.0	87.8	7,322	Gas MCF ->	2,046,426	1,000,000	2,046,426	4,045,392	1.4474
76													
77	FM GT	612	183	0.0	100.0	77.5	13,073	Light Oil BBLS ->	410	5,830,570	2,392	11,416	6.2417
78													
79	FL GT	840	5	0.0	100.0	65.1	16,793	Gas MCF ->	87	1,000,000	87	171	3.3529
80													
81	PE GT	396	21	0.0	100.0	76.0	16,793	Gas MCF ->	347	1,000,000	347	685	3.3252
82													
83	SJRPP 1O	116	83,609	99.7	82.8	99.7	9,480	Coal TONS ->	32,512	24,380,025	792,646	1,298,548	1.5531
84													
85	SJRPP 2O	116	83,435	99.7	96.0	99.7	9,405	Coal TONS ->	32,188	24,379,976	784,738	1,285,593	1.5408
86													
87	SCHER #4	610		0.0	93.8		0						
88													
89	TOTAL	16,323	5,171,798				9,699				50,161,654	73,520,857	1.4216

Date: 5/23/96

Company: Florida Power & Light

Schedule E4
Page: 4

Estimated For The Period of : Nov-96

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	406	32,955	10.9	51.2	58.4	9,711	Heavy Oil BBLS ->	49,346	6,400,002	315,816	865,333	2.6258
2			0					Gas MCF ->	4,199	1,000,000	4,199	8,416	
3													
4	TRKY O 2	403	109,814	36.7	94.3	68.9	9,458	Heavy Oil BBLS ->	160,721	6,400,000	1,028,615	2,820,519	2.5684
5			328					Gas MCF ->	13,100	1,000,000	13,100	26,252	7.9988
6													
7	TRKY N 3	688	483,089	94.4	94.2	100.0	10,676	Nuclear MBTU ->	5,157,469	1,000,000	5,157,469	1,675,179	0.3468
8													
9	TRKY N 4	688	483,089	94.4	95.0	100.0	10,676	Nuclear MBTU ->	5,157,469	1,000,000	5,157,469	1,649,392	0.3414
10													
11	FT LAUD4	452	292,752	87.1	96.0	98.3	7,729	Gas MCF ->	2,262,709	1,000,000	2,262,709	4,534,468	1.5489
12													
13	FT LAUD5	452	317,587	94.4	44.8	98.8	7,723	Gas MCF ->	2,452,864	1,000,000	2,452,864	4,915,538	1.5478
14													
15	PT EVER1	212	13,254	8.4	96.0	44.0	10,925	Heavy Oil BBLS ->	21,989	6,400,015	140,728	382,428	2.8853
16			0					Gas MCF ->	4,079	1,000,000	4,079	8,174	
17													
18	PT EVER2	213	15,049	9.5	95.8	51.7	10,641	Heavy Oil BBLS ->	24,209	6,400,008	154,938	420,886	2.7968
19			0					Gas MCF ->	5,200	1,000,000	5,200	10,421	
20													
21	PT EVER3	391	162,105	61.4	94.9	84.7	9,409	Heavy Oil BBLS ->	235,497	6,400,000	1,507,179	4,095,426	2.5264
22			16,458					Gas MCF ->	172,829	1,000,000	172,829	346,349	2.1045
23													
24	PT EVER4	387	146,623	51.9	92.2	75.9	9,533	Heavy Oil BBLS ->	216,685	6,400,000	1,386,782	3,767,064	2.5692
25			2,701					Gas MCF ->	36,715	1,000,000	36,715	73,576	2.7236
26													
27	RIV 3	292	64,686	29.8	96.0	66.6	10,587	Gas MCF ->	684,807	1,000,000	684,807	1,372,353	2.1216
28													
29	RIV 4	292	198	23.8	94.3	57.5	10,768	Heavy Oil BBLS ->	304	6,400,855	1,947	5,290	2.6771
30			51,485					Gas MCF ->	554,558	1,000,000	554,558	1,111,334	2.1586
31													

Date: 5/23/96
Company: Florida Power & Light

Schedule E4
Page: 5

Estimated For The Period of : Nov-96

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUC 1	853	602,900	95.0	95.0	100.0	10,693	Nuclear MBTU ->	6,446,652	1,000,000	6,446,652	2,346,581	0.3892
33													
34	ST LUC 2	726	513,068	95.0	95.0	100.0	10,693	Nuclear MBTU ->	5,486,096	1,000,000	5,486,096	2,183,465	0.4256
35													
36	CAP CN 1	405	61,406	45.4	93.5	69.0	9,628	Heavy Oil BBLS ->	88,522	6,399,997	566,541	1,589,043	2.5878
37			75,281					Gas MCF ->	749,502	1,000,000	749,502	1,502,003	1.9952
38													
39	CAP CN 2	403	104,364	42.2	92.7	70.1	9,477	Heavy Oil BBLS ->	151,554	6,399,998	969,947	2,724,321	2.6104
40			22,092					Gas MCF ->	228,529	1,000,000	228,529	457,972	2.0731
41													
42	SANFRD 3	147	300	0.3	95.1	50.7	10,825	Heavy Oil BBLS ->	483	6,400,041	3,089	8,288	2.7664
43			0					Gas MCF ->	154	1,000,000	154	309	
44													
45	SANFRD 4	394	51,917	17.7	96.0	49.1	10,030	Heavy Oil BBLS ->	80,274	6,400,004	513,753	1,379,679	2.6575
46			0					Gas MCF ->	6,963	1,000,000	6,963	13,953	
47													
48	SANFRD 5	394	53,086	18.3	95.2	64.8	9,842	Heavy Oil BBLS ->	80,783	6,400,002	517,008	1,388,361	2.6153
49			594					Gas MCF ->	11,320	1,000,000	11,320	22,686	3.8192
50													
51	PUTNAM 1	262	137,061	70.3	92.4	91.7	8,413	Gas MCF ->	1,153,076	1,000,000	1,153,076	2,310,764	1.6859
52													
53	PUTNAM 2	262	133,391	68.4	95.3	96.5	8,387	Gas MCF ->	1,118,691	1,000,000	1,118,691	2,241,857	1.6807
54													
55	MANATE 1	805	11,217	1.9	94.4	38.8	10,263	Heavy Oil BBLS ->	17,986	6,400,008	115,113	318,084	2.8359
56													
57	MANATE 2	805	43,207	7.2	94.4	50.7	10,026	Heavy Oil BBLS ->	67,685	6,400,000	433,182	1,196,925	2.7702
58													
59	FT MY 1	144	9,741	9.1	3.2	64.0	10,064	Heavy Oil BBLS ->	15,318	6,399,996	98,038	250,242	2.5690
60													
61	FT MY 2	394		0.0	0.0		0						
62													

Date: 5/23/96

Company: Florida Power & Light

Estimated For The Period of : Nov-96

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	CUTLER 5	72	0	0.0	96.0		0	Gas MCF ->	1	1,000,000	1	1	
64													
65	CUTLER 6	145	0	0.0	94.6		0	Gas MCF ->	2	1,000,000	2	5	2.5000
66													
67	MARTIN 1	821	9	0.0	79.6	20.9	10,005	Heavy Oil BBLS ->	13	6,384,615	83	245	2.8824
68			9					Gas MCF ->	96	1,000,000	96	267	2.8710
69													
70	MARTIN 2	805	230	0.4	86.7	30.9	10,861	Heavy Oil BBLS ->	341	6,400,293	2,183	6,429	2.8013
71			2,022					Gas MCF ->	22,271	1,000,000	22,271	61,601	3.0468
72													
73	MARTIN 3	460	330,282	96.5	95.9	99.5	7,177	Gas MCF ->	2,370,508	1,000,000	2,370,508	4,750,498	1.4383
74													
75	MARTIN 4	460	331,841	97.0	88.0	100.0	7,174	Gas MCF ->	2,380,542	1,000,000	2,380,542	4,770,606	1.4376
76													
77	FM GT	612	0	0.0	100.0		0	Light Oil BBLS ->	0	5,500,000	1	5	
78													
79	FL GT	840		0.0	100.0		0						
80													
81	PE GT	396		0.0	100.0		0						
82													
83	SJRPP 1O	116	84,877	98.0	82.8	98.0	9,396	Coal TONS ->	32,711	24,379,996	797,484	1,302,928	1.5351
84													
85	SJRPP 2O	116	85,107	98.5	96.0	98.5	9,317	Coal TONS ->	32,525	24,380,022	792,953	1,295,523	1.5222
86													
87	SCHER #4	610	397,426	87.6	93.8	88.7	10,317	Coal TONS ->	237,693	17,250,002	4,100,196	7,235,363	1.8206
88													
89	TOTAL	16,323	5,243,599				9,521				49,925,975	67,446,402	1.2863

Date: 5/23/96
Company: Florida Power & Light

Schedule E4
Page: 7

Estimated For The Period of : Dec-96

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	406	43,178	14.8	96.0	47.2	10,037	Heavy Oil	BBLS ->	66,453	6,399,997	425,299	1,143,471	2.6482
2			1					Gas	MCF ->	8,084	1,000,000	8,084	16,889	########
3														
4	TRKY O 2	403	64,979	22.4	94.3	56.6	9,670	Heavy Oil	BBLS ->	96,557	6,399,998	617,965	1,659,366	2.5537
5			31					Gas	MCF ->	10,706	1,000,000	10,706	22,389	72.4563
6														
7	TRKY N 3	719	471,719	94.4	94.2	96.6	10,678	Nuclear	MBTU ->	5,037,210	1,000,000	5,037,210	1,637,094	0.3470
8														
9	TRKY N 4	719	472,364	94.5	95.0	96.6	10,678	Nuclear	MBTU ->	5,044,103	1,000,000	5,044,103	1,614,114	0.3417
10														
11	FT LAUD4	452	283,022	87.0	96.0	98.0	7,733	Gas	MCF ->	2,188,704	1,000,000	2,188,704	4,576,579	1.6170
12														
13	FT LAUD5	452	305,764	94.0	96.0	98.5	7,727	Gas	MCF ->	2,362,631	1,000,000	2,362,631	4,941,030	1.6160
14														
15	PT EVER1	212	5,829	3.8	96.0	34.0	11,516	Heavy Oil	BBLS ->	10,100	6,400,000	64,637	170,376	2.9227
16			0					Gas	MCF ->	2,493	1,000,000	2,493	5,149	
17														
18	PT EVER2	213	5,863	3.8	95.8	53.2	10,779	Heavy Oil	BBLS ->	9,415	6,399,977	60,258	158,549	2.7042
19			0					Gas	MCF ->	2,939	1,000,000	2,939	6,088	
20														
21	PT EVER3	391	109,856	51.7	94.9	71.9	9,619	Heavy Oil	BBLS ->	160,681	6,399,999	1,028,360	2,687,294	2.4462
22			35,554					Gas	MCF ->	370,333	1,000,000	370,333	778,006	2.1883
23														
24	PT EVER4	387	110,969	41.4	92.2	61.9	9,721	Heavy Oil	BBLS ->	166,518	6,400,001	1,065,716	2,781,850	2.5069
25			4,291					Gas	MCF ->	54,760	1,000,000	54,760	114,998	2.6799
26														
27	RIV 3	292	43,850	20.9	96.0	49.9	10,982	Gas	MCF ->	481,563	1,000,000	481,563	1,004,321	2.2904
28														
29	RIV 4	292	2,200	14.6	94.3	44.6	11,197	Heavy Oil	BBLS ->	3,451	6,399,907	22,088	60,029	2.7285
30			28,563					Gas	MCF ->	322,376	1,000,000	322,376	670,725	2.3483
31														

Date: 5/23/96

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-96

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUC 1	853	580,884	94.6	95.0	100.0	10,693	Nuclear	MBTU ->	6,211,233	1,000,000	6,211,233	2,266,475	0.3902
33														
34	ST LUC 2	726	494,332	94.6	95.0	100.0	10,693	Nuclear	MBTU ->	5,285,756	1,000,000	5,285,756	2,108,485	0.4265
35														
36	CAP CN 1	405	29,249	32.5	93.5	52.1	9,944	Heavy Oil	BBLS ->	42,490	6,399,994	271,938	739,638	2.5288
37			65,647					Gas	MCF ->	671,685	1,000,000	671,685	1,402,884	2.1370
38														
39	CAP CN 2	403	62,433	33.6	92.7	60.3	9,712	Heavy Oil	BBLS ->	91,194	6,400,003	583,641	1,587,380	2.5425
40			35,195					Gas	MCF ->	364,538	1,000,000	364,538	765,813	2.1759
41														
42	SANFRD 3	147	50	0.0	95.1	78.4	10,191	Heavy Oil	BBLS ->	80	6,401,506	510	1,348	2.6960
43														
44	SANFRD 4	394	24,973	8.8	96.0	42.8	10,296	Heavy Oil	BBLS ->	39,491	6,399,993	252,745	670,517	2.6850
45			0					Gas	MCF ->	4,384	1,000,000	4,384	9,135	
46														
47	SANFRD 5	394	25,580	9.3	95.2	52.9	10,152	Heavy Oil	BBLS ->	39,964	6,400,004	255,767	679,032	2.6546
48			748					Gas	MCF ->	11,506	1,000,000	11,506	24,102	3.2239
49														
50	PUTNAM 1	262	125,863	66.7	92.4	86.0	8,447	Gas	MCF ->	1,063,109	1,000,000	1,063,109	2,224,875	1.7677
51														
52	PUTNAM 2	262	126,030	66.8	95.3	95.0	8,396	Gas	MCF ->	1,058,103	1,000,000	1,058,103	2,210,658	1.7541
53														
54	MANATE 1	805	4,409	0.8	94.4	36.8	10,248	Heavy Oil	BBLS ->	7,060	6,400,014	45,184	124,163	2.8161
55														
56	MANATE 2	805	23,490	4.1	94.4	42.9	10,246	Heavy Oil	BBLS ->	37,605	6,399,993	240,673	662,556	2.8206
57														
58	FT MY 1	144	27,753	26.8	12.4	51.3	10,356	Heavy Oil	BBLS ->	44,910	6,399,996	287,425	724,513	2.6105
59														
60	FT MY 2	394	56,087	19.8	54.7	69.1	9,537	Heavy Oil	BBLS ->	83,581	6,400,000	534,920	1,345,147	2.3983
61														

Date: 5/23/96
Company: Florida Power & Light

Estimated For The Period of : Dec-96

(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62 CUTLER 5	72		0.0	96.0		0						
64 CUTLER 6	145	0	0.0	94.6		0	Gas MCF ->	0	1,000,000	0	0	
66 MARTIN 1	821	2	0.0	79.6	17.0	9,750	Heavy Oil BBLS ->	3	6,464,286	18	53	2.9444
68 MARTIN 2	805	94	0.0	86.7	30.2	9,507	Heavy Oil BBLS ->	140	6,400,286	895	2,637	2.7994
70 MARTIN 3	460	318,572	96.2	95.9	99.2	7,180	Gas MCF ->	2,287,280	1,000,000	2,287,280	4,783,273	1.5015
72 MARTIN 4	460	320,278	96.7	88.0	99.7	7,176	Gas MCF ->	2,298,357	1,000,000	2,298,357	4,806,497	1.5007
74 FM GT	612	0	0.0	100.0		0	Light Oil BBLS ->	0		0	0	
76 FL GT	840		0.0	100.0		0						
78 PE GT	396		0.0	100.0		0						
80 SJRPP 10	116	81,414	97.2	82.8	97.4	9,403	Coal TONS ->	31,399	24,379,990	765,500	1,255,604	1.5422
82 SJRPP 20	116	81,878	97.9	96.0	97.8	9,322	Coal TONS ->	31,307	24,379,968	763,273	1,251,955	1.5291
84 SCHER #4	605	373,492	85.2	93.8	87.3	10,331	Coal TONS ->	223,684	17,250,000	3,858,556	6,690,873	1.7914
86 TOTAL	16,380	4,846,483				9,551				46,287,220	60,385,930	1.2460

Date: 5/23/96
Company: Florida Power & Light

Schedule E4
Page: 10

Estimated For The Period of : Jan-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	406	42,331	14.0	96.0	38.2	10,289	Heavy Oil	BBLS ->	67,045	6,400,005	429,086	1,137,650	2.6875
2			0					Gas	MCF ->	6,464	1,000,000	6,464	12,120	########
3														
4	TRKY O 2	403	54,107	18.2	94.3	46.8	9,848	Heavy Oil	BBLS ->	81,847	6,400,001	523,821	1,388,824	2.5668
5			487					Gas	MCF ->	13,830	1,000,000	13,830	25,942	5.3291
6														
7	TRKY N 3	719	504,857	94.4	94.2	100.0	10,688	Nuclear	MBTU ->	5,395,715	1,000,000	5,395,715	1,722,277	0.3411
8														
9	TRKY N 4	719	508,189	95.0	95.0	100.0	10,688	Nuclear	MBTU ->	5,431,333	1,000,000	5,431,333	1,711,746	0.3368
10														
11	FT LAUD4	452	282,388	84.0	96.0	98.8	7,725	Gas	MCF ->	2,181,435	1,000,000	2,181,435	4,108,185	1.4548
12														
13	FT LAUD5	452	316,998	94.3	96.0	98.7	7,724	Gas	MCF ->	2,448,530	1,000,000	2,448,530	4,608,836	1.4539
14														
15	PT EVER1	212	3,383	2.1	96.0	40.8	11,131	Heavy Oil	BBLS ->	5,707	6,399,951	36,523	94,664	2.7983
16			0					Gas	MCF ->	1,133	1,000,000	1,133	2,124	
17														
18	PT EVER2	213	4,743	3.0	95.8	36.3	11,231	Heavy Oil	BBLS ->	8,040	6,400,035	51,458	133,376	2.8121
19			0					Gas	MCF ->	1,809	1,000,000	1,809	3,392	
20														
21	PT EVER3	391	99,659	46.4	94.9	63.7	9,645	Heavy Oil	BBLS ->	145,707	6,400,001	932,527	2,417,052	2.4253
22			35,261					Gas	MCF ->	368,822	1,000,000	368,822	696,329	1.9748
23														
24	PT EVER4	387	74,440	27.6	92.2	50.7	9,930	Heavy Oil	BBLS ->	113,521	6,400,002	726,535	1,883,135	2.5297
25			4,930					Gas	MCF ->	61,645	1,000,000	61,645	117,848	2.3904
26														
27	RIV 3	292	38,109	17.5	96.0	43.7	11,183	Gas	MCF ->	426,157	1,000,000	426,157	799,085	2.0969
28														
29	RIV 4	292	2,903	14.0	94.3	36.8	11,459	Heavy Oil	BBLS ->	4,529	6,399,982	28,984	78,769	2.7138
30			27,522					Gas	MCF ->	319,641	1,000,000	319,641	599,328	2.1776
31														

Date: 5/23/96
Company: Florida Power & Light

Schedule E4
Page: 11

Estimated For The Period of : Jan-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUC 1	853	589,630	92.9	95.0	100.0	10,693	Nuclear	MBTU ->	6,304,757	1,000,000	6,304,757	2,264,628	0.3841
33														
34	ST LUC 2	726	501,776	92.9	95.0	100.0	10,693	Nuclear	MBTU ->	5,365,346	1,000,000	5,365,346	2,104,427	0.4194
35														
36	CAP CN 1	405	21,979	35.4	93.5	53.3	9,926	Heavy Oil	BBLS ->	31,979	6,399,999	204,666	544,408	2.4770
37			84,757					Gas	MCF ->	854,797	1,000,000	854,797	1,603,409	1.8918
38														
39	CAP CN 2	403	37,705	27.8	92.7	55.8	9,868	Heavy Oil	BBLS ->	55,597	6,400,002	355,819	946,472	2.5102
40			45,607					Gas	MCF ->	466,335	1,000,000	466,335	874,625	1.9178
41														
42	SANFRD 3	147	951	0.9	95.1	78.9	10,459	Heavy Oil	BBLS ->	1,505	6,400,159	9,635	25,247	2.6556
43			0					Gas	MCF ->	308	1,000,000	308	578	
44														
45	SANFRD 4	394	35,182	12.0	96.0	34.1	10,605	Heavy Oil	BBLS ->	57,532	6,400,002	368,202	964,820	2.7424
46			0					Gas	MCF ->	4,900	1,000,000	4,900	9,187	
47														
48	SANFRD 5	394	22,844	11.1	95.2	42.3	10,620	Heavy Oil	BBLS ->	35,983	6,399,998	230,291	603,443	2.6416
49			9,711					Gas	MCF ->	115,437	1,000,000	115,437	216,444	2.2288
50														
51	PUTNAM 1	262	134,039	68.8	92.4	95.1	8,361	Gas	MCF ->	1,120,658	1,000,000	1,120,658	2,109,769	1.5740
52														
53	PUTNAM 2	262	115,367	59.2	95.3	94.7	8,375	Gas	MCF ->	966,190	1,000,000	966,190	1,817,379	1.5753
54														
55	MANATE 1	805	9,230	1.5	94.4	50.1	10,166	Heavy Oil	BBLS ->	14,661	6,399,984	93,828	257,788	2.7930
56														
57	MANATE 2	805	17,756	3.0	94.4	47.0	10,292	Heavy Oil	BBLS ->	28,553	6,399,987	182,740	502,072	2.8277
58														
59	FT MY 1	144	22,187	20.7	96.0	52.4	10,363	Heavy Oil	BBLS ->	35,924	6,399,993	229,913	572,979	2.5825
60														
61	FT MY 2	394	177,047	60.4	94.2	74.1	9,375	Heavy Oil	BBLS ->	259,339	6,400,001	1,659,771	4,137,280	2.3368
62														

Date: 5/23/96

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	CUTLER 5	72	42	0.1	96.0	89.0	11,582	Gas MCF ->	484	1,000,000	484	907	2.1699
64													
65	CUTLER 6	145	119	0.1	94.6	83.3	11,249	Gas MCF ->	1,337	1,000,000	1,337	2,506	2.1094
66													
67	MARTIN 1	821	248	0.3	79.6	33.1	11,320	Heavy Oil BBLS ->	413	6,400,532	2,645	7,789	3.1407
68			1,885					Gas MCF ->	21,500	1,000,000	21,500	55,984	2.9703
69													
70	MARTIN 2	805	641	0.5	86.7	40.7	10,568	Heavy Oil BBLS ->	1,009	6,400,159	6,458	19,020	2.9668
71			2,298					Gas MCF ->	24,605	1,000,000	24,605	64,098	2.7888
72													
73	MARTIN 3	460	328,565	96.0	95.9	99.3	7,178	Gas MCF ->	2,358,583	1,000,000	2,358,583	4,439,622	1.3512
74													
75	MARTIN 4	460	331,047	96.7	88.0	99.7	7,176	Gas MCF ->	2,375,518	1,000,000	2,375,518	4,471,464	1.3507
76													
77	FM GT	612	192	0.0	100.0	86.1	13,073	Light Oil BBLS ->	430	5,830,544	2,508	11,973	6.2392
78													
79	FL GT	840	34	0.0	100.0	82.4	16,793	Gas MCF ->	571	1,000,000	571	1,071	3.1500
80													
81	PE GT	396	52	0.0	100.0	87.8	16,793	Gas MCF ->	866	1,000,000	866	1,623	3.1515
82													
83	SJRPP 1O	116	84,101	97.4	82.8	97.4	9,397	Coal TONS ->	32,417	24,379,993	790,324	1,313,228	1.5615
84													
85	SJRPP 2O	116	84,744	97.9	96.0	97.9	9,318	Coal TONS ->	32,389	24,379,984	789,631	1,312,074	1.5483
86													
87	SCHER #4	605	295,918	65.7	93.8	81.2	10,335	Coal TONS ->	177,302	17,250,001	3,058,456	5,255,105	1.7759
88													
89	TOTAL	16,380	4,955,957				9,555				47,352,523	58,052,101	1.1714

Estimated For The Period of : Feb-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	406	21,844	15.5	96.0	48.0	10,221	Heavy Oil	BBLS ->	33,172	6,399,993	212,303	561,787	2.5718
2			20,507					Gas	MCF ->	220,548	1,000,000	220,548	509,139	2.4827
3														
4	TRKY O 2	403	21,074	19.8	94.3	52.4	10,062	Heavy Oil	BBLS ->	31,332	6,399,996	200,525	530,881	2.5192
5			32,612					Gas	MCF ->	339,643	1,000,000	339,643	784,717	2.4063
6														
7	TRKY N 3	719	456,000	94.4	94.2	100.0	10,688	Nuclear	MBTU ->	4,873,550	1,000,000	4,873,550	1,554,662	0.3409
8														
9	TRKY N 4	719	459,010	95.0	95.0	100.0	10,688	Nuclear	MBTU ->	4,905,720	1,000,000	4,905,720	1,545,302	0.3367
10														
11	FT LAUD4	452	277,633	91.4	96.0	98.8	7,723	Gas	MCF ->	2,144,294	1,000,000	2,144,294	3,597,892	1.2959
12														
13	FT LAUD5	452	286,187	94.2	96.0	99.0	7,723	Gas	MCF ->	2,210,150	1,000,000	2,210,150	3,719,784	1.2998
14														
15	PT EVER1	212	2,711	2.2	96.0	39.1	11,263	Heavy Oil	BBLS ->	4,580	6,399,943	29,314	75,759	2.7948
16			483					Gas	MCF ->	6,659	1,000,000	6,659	14,795	3.0619
17														
18	PT EVER2	213	3,464	3.2	95.8	47.8	10,871	Heavy Oil	BBLS ->	5,683	6,399,951	36,369	94,068	2.7155
19			1,095					Gas	MCF ->	13,199	1,000,000	13,199	29,782	2.7188
20														
21	PT EVER3	391	23,397	59.4	94.9	78.2	9,696	Heavy Oil	BBLS ->	33,739	6,399,999	215,928	559,673	2.3921
22			132,582					Gas	MCF ->	1,296,388	1,000,000	1,296,388	2,973,341	2.2427
23														
24	PT EVER4	387	21,754	38.1	92.2	60.0	10,065	Heavy Oil	BBLS ->	32,481	6,400,001	207,877	538,584	2.4758
25			77,442					Gas	MCF ->	790,545	1,000,000	790,545	1,836,695	2.3717
26														
27	RIV 3	292	73,713	37.6	96.0	61.3	10,669	Gas	MCF ->	786,422	1,000,000	786,422	1,319,714	1.7903
28														
29	RIV 4	292	8,302	20.2	94.3	50.1	10,894	Heavy Oil	BBLS ->	13,032	6,400,017	83,406	226,673	2.7305
30			31,391					Gas	MCF ->	349,002	1,000,000	349,002	597,393	1.9031
31														

Estimated For The Period of : Feb-97

(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
ST LUC 1	853	532,569	92.9	95.0	100.0	10,693	Nuclear	MBTU ->	5,694,618	1,000,000	5,694,618	2,044,368	0.3839
ST LUC 2	726	453,217	92.9	95.0	100.0	10,693	Nuclear	MBTU ->	4,846,119	1,000,000	4,846,119	1,899,679	0.4192
CAP CN 1	405	4,872	47.5	93.5	66.3	9,826	Heavy Oil	BBLS ->	7,017	6,400,000	44,906	119,448	2.4516
		124,537					Gas	MCF ->	1,226,609	1,000,000	1,226,609	2,436,364	1.9563
CAP CN 2	403	11,236	35.7	92.7	63.2	9,900	Heavy Oil	BBLS ->	16,297	6,400,009	104,300	277,437	2.4693
		85,522					Gas	MCF ->	853,648	1,000,000	853,648	1,920,442	2.2456
SANFRD 3	147	443	0.5	95.1	71.9	10,525	Heavy Oil	BBLS ->	704	6,400,000	4,502	11,723	2.6445
		56					Gas	MCF ->	755	1,000,000	755	1,654	2.9431
SANFRD 4	394	18,948	10.7	96.0	43.5	10,420	Heavy Oil	BBLS ->	29,713	6,399,997	190,160	497,079	2.6234
		9,312					Gas	MCF ->	104,313	1,000,000	104,313	240,259	2.5802
SANFRD 5	394	10,530	9.5	95.2	53.1	10,378	Heavy Oil	BBLS ->	16,292	6,399,985	104,269	273,223	2.5947
		14,605					Gas	MCF ->	156,578	1,000,000	156,578	359,898	2.4642
PUTNAM 1	262	142,058	80.7	92.4	97.3	8,363	Gas	MCF ->	1,187,964	1,000,000	1,187,964	1,990,355	1.4011
PUTNAM 2	262	129,232	73.4	95.3	96.8	8,376	Gas	MCF ->	1,082,491	1,000,000	1,082,491	1,806,810	1.3981
MANATE 1	805	2,023	0.4	94.4	30.0	10,854	Heavy Oil	BBLS ->	3,430	6,399,907	21,954	60,281	2.9804
MANATE 2	805	5,824	1.1	94.4	35.1	10,587	Heavy Oil	BBLS ->	9,634	6,400,000	61,658	169,302	2.9071
FT MY 1	144	23,575	24.4	96.0	61.7	10,198	Heavy Oil	BBLS ->	37,565	6,399,988	240,416	591,979	2.5111
FT MY 2	394	177,467	67.0	94.2	83.0	9,329	Heavy Oil	BBLS ->	258,695	6,400,002	1,655,650	4,074,541	2.2959

Estimated For The Period of : Feb-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	CUTLER 5	72	1	0.0	96.0		0	Gas	MCF ->	8	1,000,000	8	12	2.0000
64														
65	CUTLER 6	145	4	0.0	94.6	75.5	11,249	Gas	MCF ->	44	1,000,000	44	72	1.8462
66														
67	MARTIN 1	821	73	0.0	79.6	42.5	9,753	Heavy Oil	BBLS ->	111	6,399,095	707	2,082	2.8717
68			1					Gas	MCF ->	5	1,000,000	5	12	2.4000
69														
70	MARTIN 2	805	1,442	0.3	86.7	23.2	11,173	Heavy Oil	BBLS ->	2,452	6,400,114	15,692	46,195	3.2044
71			12					Gas	MCF ->	548	1,000,000	548	983	8.1917
72														
73	MARTIN 3	460	298,103	96.4	95.9	99.8	7,175	Gas	MCF ->	2,138,957	1,000,000	2,138,957	3,602,234	1.2084
74														
75	MARTIN 4	460	277,334	89.7	89.1	92.9	7,212	Gas	MCF ->	2,000,103	1,000,000	2,000,103	3,374,849	1.2169
76														
77	FM GT	612	2	0.0	100.0	79.9	13,073	Light Oil	BBLS ->	4	5,756,757	21	102	6.3750
78														
79	FL GT	840	0	0.0	100.0		0	Gas	MCF ->	0	1,000,000	0	0	
80														
81	PE GT	396	0	0.0	100.0		0	Gas	MCF ->	1	1,000,000	1	2	2.0000
82														
83	SJRPP 1O	116	76,353	97.9	2.7	97.9	9,397	Coal	TONS ->	29,430	24,379,990	717,496	1,203,765	1.5766
84														
85	SJRPP 2O	116	76,913	98.4	96.0	98.4	9,319	Coal	TONS ->	29,398	24,379,988	716,723	1,202,458	1.5634
86														
87	SCHER #4	605	354,792	87.3	93.8	92.0	10,295	Coal	TONS ->	211,742	17,249,998	3,652,551	6,263,703	1.7655
88														
89	TOTAL	16,380	4,782,250				9,566					45,745,605	55,541,952	1.1614

Date: 5/23/96

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Mar-97

(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
TRKY O 1	406	62,708	32.0	96.0	69.8	9,724	Heavy Oil BBLS ->	92,427	6,400,000	591,532	1,546,775	2.4666
		33,955					Gas MCF ->	348,447	1,000,000	348,447	736,839	2.1700
TRKY O 2	403	20,226	39.7	94.3	73.5	9,800	Heavy Oil BBLS ->	29,250	6,399,995	187,201	489,496	2.4202
		98,699					Gas MCF ->	978,292	1,000,000	978,292	2,076,823	2.1042
TRKY N 3	719	162,857	30.4	21.3	100.0	10,688	Nuclear MBTU ->	1,740,553	1,000,000	1,740,553	560,458	0.3441
TRKY N 4	719	508,189	95.0	95.0	100.0	10,688	Nuclear MBTU ->	5,431,333	1,000,000	5,431,333	1,710,870	0.3367
FT LAUD4	452	200,470	59.6	65.0	98.8	7,723	Gas MCF ->	1,548,323	1,000,000	1,548,323	2,343,280	1.1689
FT LAUD5	452	319,686	95.1	96.0	99.4	7,720	Gas MCF ->	2,467,906	1,000,000	2,467,906	3,700,371	1.1575
PT EVER1	212	17,086	12.1	96.0	62.2	10,445	Heavy Oil BBLS ->	27,119	6,399,989	173,558	446,616	2.6140
		2,061					Gas MCF ->	26,433	1,000,000	26,433	53,892	2.6147
PT EVER2	213	17,750	12.8	95.8	63.6	10,434	Heavy Oil BBLS ->	27,828	6,400,001	178,099	458,300	2.5820
		2,548					Gas MCF ->	33,685	1,000,000	33,685	68,007	2.6689
PT EVER3	391	3,971	71.3	94.9	87.7	9,647	Heavy Oil BBLS ->	5,635	6,399,954	36,066	92,809	2.3372
		203,459					Gas MCF ->	1,965,082	1,000,000	1,965,082	4,210,925	2.0697
PT EVER4	387	9,418	3.3	0.0	56.5	10,245	Gas MCF ->	96,487	1,000,000	96,487	224,159	2.3802
RIV 3	292	118,048	54.3	96.0	79.0	10,393	Gas MCF ->	1,226,909	1,000,000	1,226,909	1,827,606	1.5482
RIV 4	292	85,134	39.2	94.3	72.1	10,544	Gas MCF ->	897,650	1,000,000	897,650	1,428,621	1.6781
ST LUC 1	853	589,630	92.9	95.0	100.0	10,693	Nuclear MBTU ->	6,304,757	1,000,000	6,304,757	2,263,407	0.3839

Date: 5/23/96
Company: Florida Power & Light

Estimated For The Period of : Mar-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUC 2	726	501,776	92.9	95.0	100.0	10,693	Nuclear	MBTU ->	5,365,346	1,000,000	5,365,346	2,103,216	0.4192
34	CAP CN 1	405	183,122	60.8	93.5	78.8	9,725	Gas	MCF ->	1,780,873	1,000,000	1,780,873	3,334,536	1.8209
36	CAP CN 2	403	172,182	57.4	92.7	79.1	9,785	Gas	MCF ->	1,684,839	1,000,000	1,684,839	3,544,343	2.0585
38	SANFRD 3	147	5,165	4.8	95.1	75.5	10,394	Heavy Oil	BBLS ->	8,145	6,400,020	52,126	134,162	2.5975
39			71					Gas	MCF ->	2,300	1,000,000	2,300	3,881	5.4662
41	SANFRD 4	394	60,754	25.1	96.0	63.0	9,940	Heavy Oil	BBLS ->	92,470	6,399,997	591,810	1,523,212	2.5072
42			12,745					Gas	MCF ->	138,781	1,000,000	138,781	290,444	2.2788
44	SANFRD 5	394	66,669	22.7	95.2	71.9	10,248	Gas	MCF ->	683,192	1,000,000	683,192	1,445,411	2.1680
46	PUTNAM 1	262	157,387	80.7	56.6	92.2	8,397	Gas	MCF ->	1,321,522	1,000,000	1,321,522	1,979,607	1.2578
48	PUTNAM 2	262	148,741	76.3	95.3	92.4	8,405	Gas	MCF ->	1,250,220	1,000,000	1,250,220	1,872,980	1.2592
50	MANATE 1	805	31,205	5.2	94.4	51.9	10,011	Heavy Oil	BBLS ->	48,813	6,400,006	312,405	842,079	2.6985
52	MANATE 2	805	57,340	9.6	94.4	56.6	9,845	Heavy Oil	BBLS ->	88,202	6,400,000	564,493	1,521,597	2.6536
54	FT MY 1	144	48,903	45.6	96.0	78.2	9,979	Heavy Oil	BBLS ->	76,253	6,400,005	488,020	1,178,860	2.4106
56	FT MY 2	394	223,568	76.3	94.2	89.1	9,295	Heavy Oil	BBLS ->	324,685	6,400,000	2,077,987	5,023,999	2.2472
58	CUTLER 5	72	2	0.0	96.0	79.7	11,582	Gas	MCF ->	20	1,000,000	20	30	1.7647
60	CUTLER 6	145	12	0.0	94.6	71.8	11,249	Gas	MCF ->	140	1,000,000	140	206	1.6613

Date: 5/23/96
Company: Florida Power & Light

Schedule E4
Page: 18

Estimated For The Period of : Mar-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MARTIN 1	821	321	0.1	79.6	34.3	9,750	Heavy Oil BBLS ->	490	6,399,387	3,133	9,211	2.8668
63			0					Gas MCF ->	1	1,000,000	1	2	2.0000
64													
65	MARTIN 2	805	4,366	0.7	86.7	41.7	9,808	Heavy Oil BBLS ->	6,624	6,400,027	42,393	124,655	2.8551
66			5					Gas MCF ->	481	1,000,000	481	741	14.5294
67													
68	MARTIN 3	460	330,111	96.5	95.9	99.8	7,175	Gas MCF ->	2,368,561	1,000,000	2,368,561	3,551,607	1.0759
69													
70	MARTIN 4	460	332,013	97.0	88.0	100.0	7,174	Gas MCF ->	2,381,744	1,000,000	2,381,744	3,571,599	1.0757
71													
72	FM GT	612	4	0.0	100.0	78.2	13,073	Light Oil BBLS ->	9	5,816,092	51	242	6.2051
73													
74	FL GT	840	0	0.0	100.0		0	Gas MCF ->	0	1,000,000	0	0	
75													
76	PE GT	396	0	0.0	100.0		0	Gas MCF ->	2	1,000,000	2	3	3.0000
77													
78	SJRPP 1O	116	8,239	9.5	82.8	98.6	9,390	Coal TONS ->	3,174	24,379,663	77,371	130,062	1.5785
79													
80	SJRPP 2O	116	85,879	99.2	96.0	99.2	9,316	Coal TONS ->	32,816	24,379,987	800,063	1,350,787	1.5729
81													
82	SCHER #4	605	430,868	95.7	93.8	95.7	10,276	Coal TONS ->	256,677	17,250,002	4,427,677	7,610,360	1.7663
83													
84	TOTAL	16,380	5,317,342				9,525				50,647,861	65,387,086	1.2297

Date: 5/23/96
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-96 Thru Mar-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	406	324,991	21.6	85.2	58.8	9,844	Heavy Oil BBLS ->	490,275	6,400,001	3,137,761	8,481,033	2.6096
2			56,278					Gas MCF ->	615,511	1,000,000	615,511	1,339,293	2.3798
3													
4	TRKY O 2	403	397,456	30.4	94.3	64.3	9,686	Heavy Oil BBLS ->	588,063	6,399,999	3,763,604	10,230,845	2.5741
5			134,479					Gas MCF ->	1,388,596	1,000,000	1,388,596	3,002,667	2.2328
6													
7	TRKY N 3	709	2,531,576	82.2	81.8	98.5	10,741	Nuclear MBTU ->	27,191,374	1,000,000	27,191,374	8,768,577	0.3464
8													
9	TRKY N 4	709	2,883,895	93.7	95.0	98.9	10,734	Nuclear MBTU ->	30,956,835	1,000,000	30,956,835	9,823,734	0.3406
10													
11	FT LAUD4	452	1,633,774	83.2	90.7	97.9	7,737	Gas MCF ->	12,640,786	1,000,000	12,640,786	23,739,660	1.4531
12													
13	FT LAUD5	452	1,672,808	85.2	87.3	98.6	7,728	Gas MCF ->	12,926,979	1,000,000	12,926,979	23,837,201	1.4250
14													
15	PT EVER1	212	80,483	9.0	96.0	57.9	10,563	Heavy Oil BBLS ->	129,840	6,399,995	830,975	2,234,790	2.7767
16			2,548					Gas MCF ->	46,043	1,000,000	46,043	94,503	3.7095
17													
18	PT EVER2	213	90,627	10.2	95.8	61.2	10,451	Heavy Oil BBLS ->	144,074	6,400,001	922,076	2,481,062	2.7377
19			3,653					Gas MCF ->	63,261	1,000,000	63,261	130,400	3.5697
20													
21	PT EVER3	391	593,091	60.8	94.9	78.4	9,585	Heavy Oil BBLS ->	868,611	6,400,000	5,559,113	14,923,239	2.5162
22			440,417					Gas MCF ->	4,347,427	1,000,000	4,347,427	9,351,005	2.1232
23													
24	PT EVER4	387	533,936	38.0	76.4	66.3	9,714	Heavy Oil BBLS ->	796,902	6,400,000	5,100,174	13,694,770	2.5649
25			105,622					Gas MCF ->	1,112,643	1,000,000	1,112,643	2,512,482	2.3787
26													
27	RIV 3	292	427,685	33.7	96.0	65.0	10,637	Gas MCF ->	4,549,334	1,000,000	4,549,334	8,187,615	1.9144
28													
29	RIV 4	292	16,454	25.7	94.3	58.8	10,787	Heavy Oil BBLS ->	25,708	6,400,000	164,531	447,147	2.7176
30			308,950					Gas MCF ->	3,345,494	1,000,000	3,345,494	6,190,502	2.0037
31													

Date: 5/23/96

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-96 Thru Mar-97

(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
ST LUC 1	853	3,469,809	93.6	95.0	99.7	10,714	Nuclear	MBTU ->	37,175,149	1,000,000	37,175,149	13,448,282	0.3876
ST LUC 2	726	2,952,809	93.6	95.0	99.7	10,714	Nuclear	MBTU ->	31,636,034	1,000,000	31,636,034	12,504,880	0.4235
CAP CN 1	405	137,450	47.2	93.5	66.1	9,795	Heavy Oil	BBLS ->	199,151	6,399,997	1,274,566	3,523,975	2.5638
		692,961					Gas	MCF ->	6,859,164	1,000,000	6,859,164	13,394,403	1.9329
CAP CN 2	403	305,378	42.9	92.7	68.7	9,734	Heavy Oil	BBLS ->	446,956	6,400,000	2,860,521	7,948,437	2.6028
		446,317					Gas	MCF ->	4,456,266	1,000,000	4,456,266	9,260,735	2.0749
SANFRD 3	147	8,138	1.3	95.1	75.0	10,425	Heavy Oil	BBLS ->	12,867	6,400,017	82,347	214,411	2.6346
		127					Gas	MCF ->	3,825	1,000,000	3,825	7,035	5.5307
SANFRD 4	394	252,729	16.1	96.0	51.6	10,120	Heavy Oil	BBLS ->	393,271	6,400,000	2,516,935	6,652,845	2.6324
		22,116					Gas	MCF ->	264,588	1,000,000	264,588	573,383	2.5926
SANFRD 5	394	220,597	18.7	95.2	63.6	10,091	Heavy Oil	BBLS ->	338,960	6,399,999	2,169,343	5,805,856	2.6319
		99,173					Gas	MCF ->	1,057,568	1,000,000	1,057,568	2,226,481	2.2451
PUTNAM 1	262	846,376	74.4	86.3	92.2	8,381	Gas	MCF ->	7,093,157	1,000,000	7,093,157	13,080,982	1.5455
PUTNAM 2	262	781,761	68.7	95.3	94.2	8,378	Gas	MCF ->	6,549,614	1,000,000	6,549,614	1[illegible],073,413	1.5444
MANATE 1	805	132,829	3.8	94.4	49.4	10,115	Heavy Oil	BBLS ->	209,935	6,400,001	1,343,582	3,693,169	2.7804
MANATE 2	805	287,211	8.2	94.4	57.6	9,938	Heavy Oil	BBLS ->	445,982	6,399,998	2,854,286	7,850,075	2.7332
FT MY 1	144	132,159	21.1	66.2	62.2	10,168	Heavy Oil	BBLS ->	209,971	6,399,997	1,343,812	3,318,573	2.5110
FT MY 2	394	680,598	39.8	57.9	81.2	9,356	Heavy Oil	BBLS ->	994,972	6,400,001	6,367,820	15,700,178	2.3068

Date: 5/23/96

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-96 Thru Mar-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	CUTLER 5	72	101	0.0	96.0	69.9	11,715	Gas MCF ->	1,180	1,000,000	1,180	2,271	2.2552
65													
66													
67	CUTLER 6	145	291	0.0	94.6	100.0	11,357	Gas MCF ->	3,302	1,000,000	3,302	6,309	2.1703
68													
69	MARTIN 1	821	759	0.4	79.6	35.7	11,082	Heavy Oil BBLS ->	1,198	6,399,582	7,664	22,556	2.9714
70			12,134					Gas MCF ->	135,221	1,000,000	135,221	365,338	3.0109
71													
72	MARTIN 2	805	8,430	1.4	86.7	43.3	10,427	Heavy Oil BBLS ->	13,108	6,400,035	83,889	246,855	2.9283
73			40,426					Gas MCF ->	425,503	1,000,000	425,503	1,151,336	2.8480
74													
75	MARTIN 3	460	1,906,493	95.4	95.9	98.5	7,195	Gas MCF ->	13,717,809	1,000,000	13,717,809	25,466,396	1.3358
76													
77	MARTIN 4	460	1,871,999	93.7	85.1	96.8	7,202	Gas MCF ->	13,482,691	1,000,000	13,482,691	25,040,407	1.3376
78													
79	FM GT	612	380	0.0	100.0	100.0	13,077	Light Oil BBLS ->	853	5,830,129	4,973	23,738	6.2419
80													
81	FL GT	840	39	0.0	100.0	100.0	16,831	Gas MCF ->	658	1,000,000	658	1,242	3.1765
82			0						0		0	0	0.0000
83													
84	PE GT	396	72	0.0	100.0	100.0	16,811	Gas MCF ->	1,215	1,000,000	1,215	2,313	3.1992
85			0						0		0	0	0.0000
86													
87	SJRPP 1O	116	418,593	83.1	70.4	98.3	9,414	Coal TONS ->	161,642	24,379,993	3,940,821	6,504,135	1.5538
88													
89	SJRPP 2O	116	497,955	98.8	96.0	98.8	9,333	Coal TONS ->	190,623	24,379,988	4,647,382	7,698,390	1.5460
90													
91	SCHER #4	607	1,852,497	70.3	93.8	89.2	10,309	Coal TONS ->	1,107,098	17,250,001	19,097,436	33,055,404	1.7844
92													
93	TOTAL	16,361	30,317,429				9,569				290,120,838	380,334,328	1.2545

Date 5/23/96
Company: Florida Power & Light

Schedule: E5
Page: 1

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : October 1996 thru March 1997

			October 1996	November 1996	December 1996	January 1997	February 1997	March 1997	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	1,569,832	1,011,382	896,242	851,149	460,108	977,941	5,772,654
3	Unit Cost	($/BBLS)	18.1242	17.0786	15.9533	16.2709	15.8139	15.8169	16.7533
4	Amount	($)	28,452,000	17,273,000	14,298,000	13,849,000	7,371,000	15,468,000	96,711,000
5									
6	Burned:								
7	Units	(BBLS)	1,885,682	1,211,708	899,693	948,892	535,926	827,941	6,309,842
8	Unit Cost	($/BBLS)	17.6255	17.5113	16.8923	16.5612	16.2538	16.1748	17.0321
9	Amount	($)	33,236,066	21,218,560	15,197,921	15,714,738	8,710,715	13,391,770	107,469,810
10									
11	Ending Inventory:								
12	Units	(BBLS)	3,440,582	3,240,255	3,236,803	3,139,061	3,069,241	3,219,241	3,219,241
13	Unit Cost	($/BBLS)	17.7036	17.5807	17.3211	17.2659	17.2221	17.0645	17.0545
14	Amount	($)	60,910,585	56,965,979	56,065,150	54,198,868	52,858,747	54,934,872	54,934,872
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	0	0	0	0	0	0	0
21	Unit Cost	($/BBLS)							
22	Amount	($)	0	0	0	0	0	0	0
23									
24	Burned:								
25	Units	(BBLS)	410	0	0	430	4	9	853
26	Unit Cost	($/BBLS)	27.8439			27.8442	25.5000	26.8889	27.8288
27	Amount	($)	11,416	5	0	11,973	102	242	23,738
28									
29	Ending Inventory:								
30	Units	(BBLS)	179,554	179,554	179,554	179,124	179,120	179,111	179,111
31	Unit Cost	($/BBLS)	29.6004	29.6004	29.6004	29.6046	29.6047	29.6048	29.6048
32	Amount	($)	5,314,876	5,314,871	5,314,870	5,302,898	5,302,796	5,302,554	5,302,554
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	79,836	51,486	50,773	57,642	57,236	42,007	338,980
39	Unit Cost	($/Tons)	40.0070	39.5836	40.2970	41.0985	41.3726	41.4455	40.5806
40	Amount	($)	3,194,000	2,038,000	2,046,000	2,369,000	2,368,000	1,741,000	13,756,000
41									
42	Burned:								
43	Units	(Tons)	64,700	65,235	62,706	64,805	58,829	35,990	352,264
44	Unit Cost	($/Tons)	39.9404	39.8321	39.9891	40.5108	40.9027	41.1462	40.3178
45	Amount	($)	2,584,141	2,598,449	2,507,558	2,625,302	2,406,222	1,480,850	14,202,522
46									
47	Ending Inventory:								
48	Units	(Tons)	92,120	78,370	66,437	59,274	57,682	63,699	63,699
49	Unit Cost	($/Tons)	39.9426	39.8054	40.0101	40.5272	40.9834	41.1965	41.1965
50	Amount	($)	3,679,511	3,119,553	2,658,154	2,402,208	2,364,002	2,624,175	2,624,175
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	2,104,983	4,278,155	4,193,303	3,664,435	4,305,186	4,437,770	22,983,831
57	Unit Cost	($/MBTU)	1.8071	1.7281	1.6970	1.6971	1.7100	1.7270	1.7211
58	Amount	($)	3,804,000	7,393,000	7,116,000	6,219,000	7,362,000	7,664,000	39,558,000
59									
60	Burned:								
61	Units	(MBTU)	0	4,100,204	3,858,549	3,058,460	3,652,550	4,427,678	19,097,441
62	Unit Cost	($/MBTU)		1.7646	1.7340	1.7182	1.7149	1.7188	1.7309
63	Amount	($)	0	7,235,363	6,690,873	5,255,105	6,263,702	7,610,360	33,055,403
64									
65	Ending Inventory:								
66	Units	(MBTU)	5,304,427	5,482,395	5,817,131	6,423,107	7,075,743	7,085,852	7,085,852
67	Unit Cost	($/MBTU)	1.7885	1.7592	1.7310	1.7177	1.7145	1.7196	1.7196
68	Amount	($)	9,487,213	9,644,502	10,069,863	11,033,104	12,131,270	12,184,938	12,184,938
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	14,951,091	14,126,935	13,463,276	14,050,382	16,815,582	21,106,610	94,513,876
75	Unit Cost	($/MCF)	3.0691	3.0930	3.2879	2.9777	2.6464	2.3698	2.8589
76	Amount	($)	45,886,550	43,694,890	44,265,320	41,837,140	44,500,120	50,018,190	270,202,210
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	21,474,283	22,247,686	21,578,302	22,497,151	20,320,007	18,841,969	126,959,398
83	Unit Cost	($/MBTU)	0.3530	0.3531	0.3534	0.3468	0.3467	0.3523	0.3509
84	Amount	($)	7,579,648	7,854,617	7,626,168	7,803,078	7,044,011	6,637,951	44,545,473

POWER SOLD

Estimated For the Period of : October 1996 Thru March 1997

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost (Cents / KWH)	(8) Total $ For Fuel Adjustment (6) * (7A)
October 1996		C	43,596		43,596	3.123	4.098	1,361,491
		OS	8,750		8,750	3.123	4.123	273,274
		S			0			0
	St.Lucie Rel.		42,676		42,676	0.388	0.388	165,610
	80% of Gain							340,046
Total			95,022	0	95,022	1.895	2.434	2,140,421
November 1996		C	39,388		39,388	2.773	3.768	1,092,232
		OS	13,528		13,528	2.773	3.773	375,128
		S			0			0
	St.Lucie Rel.		44,809		44,809	0.388	0.388	174,030
	80% of Gain							313,530
Total			97,725	0	97,725	1.880	2.219	1,954,920
December 1996		C	51,050		51,050	2.373	3.251	1,211,415
		OS	6,538		6,538	2.373	3.373	155,148
		S			0			0
	St.Lucie Rel.		43,382		43,382	0.389	0.389	168,620
	80% of Gain							358,574
Total			100,970	0	100,970	1.520	2.029	1,893,757
January 1996		C	24,427		24,427	2.795	3.302	682,726
		OS	12,321		12,321	2.795	3.302	344,381
		S			0			0
	St.Lucie Rel.		44,901		44,901	0.382	0.382	171,660
	80% of Gain							99,074
Total			81,649	0	81,649	1.468	1.898	1,297,841
February 1996		C	33,323		33,323	2.787	3.392	928,720
		OS	12,816		12,816	2.787	3.427	357,174
		S			0			0
	St.Lucie Rel.		40,556		40,556	0.383	0.383	155,100
	80% of Gain							161,285
Total			86,695	0	86,695	1.862	1.989	1,602,359
March 1996		C	21,824		21,824	2.468	2.874	538,615
		OS	34,173		34,173	2.468	3.037	843,391
		S			0			0
	St.Lucie Rel.		44,901		44,901	0.383	0.383	171,900
	80% of Gain							70,884
Total			100,898	0	100,898	1.540	1.821	1,624,790
Period Total		C	213,608		213,608	2.722	3.509	5,815,199
		OS	88,126		88,12[illegible]	2.665	3.377	2,348,496
		S	0		0			0
	St.Lucie Rel.		261,225		261,225	0.385	0.385	1,007,000
	80% of Gain							1,343,394
Total			562,959	0	562,959	1.629	2.039	10,514,089

Date:
Company: Florida Power & Light

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated fof the Period of : October 1996 thru March 1997

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
1996	Sou. Co. (UPS + R)		442,630			442,630	1.662		7,357,770
October	St. Lucie Rel.		42,673			42,673	0.425		181,200
	SJRPP		250,463			250,463	1.549		3,880,020
Total			735,766			735,766	1.552		11,418,990
1996	Sou. Co. (UPS + R)		444,736			444,736	1.631		7,253,340
November	St. Lucie Rel.		44,807			44,807	0.425		190,400
	SJRPP		254,950			254,950	1.523		3,881,720
Total			744,493			744,493	1.521		11,325,460
1996	Sou. Co. (UPS + R)		494,757			494,757	1.589		7,862,510
December	St. Lucie Rel.		43,379			43,379	0.425		184,400
	SJRPP		244,956			244,956	1.545		3,783,980
Total			783,092			783,092	1.511		11,830,890
1997	Sou. Co. (UPS + R)		243,064			243,064	1.647		4,003,010
January	St. Lucie Rel.		44,899			44,899	0.418		187,600
	SJRPP		253,338			253,338	1.577		3,994,060
Total			541,301			541,301	1.512		8,184,670
1997	Sou. Co. (UPS + R)		285,891			285,891	1.692		4,836,450
February	St. Lucie Rel.		40,554			40,554	0.418		169,600
	SJRPP		230,024			230,024	1.586		3,648,470
Total			556,469			556,469	1.555		[illegible],654,520
1997	Sou. Co. (UPS + R)		423,530			423,530	1.761		7,459,200
March	St. Lucie Rel.		44,899			44,899	0.418		187,800
	SJRPP		141,170			141,170	1.584		2,236,420
Total			609,599			609,599	1.621		9,883,420
	Sou. Co. (UPS + R)		2,334,608			2,334,608	1.661		38,772,280
Period	St. Lucie Rel.		261,211			261,211	0.421		1,101,000
Total	SJRPP		1,374,901			1,374,901	1.558		21,424,670
Total			3,970,720			3,970,720	1.544		61,297,950

Date: 5/29/96
Company: Florida Power & Light

Schedule: E8
Page : 1

Energy Payment to Qualifying Facilities

Estimated fol the Period of : October 1996 thru March 1997

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
1996 October	Qual. Facilities		626,686			626,686	1.965	1.965	12,311,614
Total			626,686			626,686	1.965	1.965	12,311,614
1996 November	Qual. Facilities		491,648			491,648	1.865	1.865	9,167,292
Total			491,648			491,648	1.865	1.865	9,167,292
1996 December	Qual. Facilities		531,763			531,763	1.837	1.837	9,768,527
Total			531,763			531,763	1.837	1.837	9,768,527
1997 January	Qual. Facilities		498,557			498,557	1.896	1.896	9,454,222
Total			498,557			498,557	1.896	1.896	9,454,222
1997 February	Qual. Facilities		434,482			434,482	1.895	1.895	8,231,852
Total			434,482			434,482	1.895	1.895	8,231,852
1997 March	Qual. Facilities		385,682			385,682	1.922	1.922	7,412,497
Total			385,682			385,682	1.922	1.922	7,412,497
Period Total	Qual. Facilities		2,968,817			2,968,817	1.898	1.898	56,346,004
Total			2,968,817			2,968,817	1.898	1.898	56,346,004

Economy Energy Purchases

Estimated For the Period of : October 1996 Thru March 1997

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
October	Florida	C	314,244	1.804	5,668,950	2.049	6,438,848	769,898
1996	Southern Co.	C	282,944	2.165	6,125,090	2.410	6,818,300	693,210
Total			597,188	1.975	11,794,040	2.220	13,257,148	1,463,108
November	Florida	C	108,740	1.804	1,961,670	2.030	2,207,422	245,752
1996	Southern Co.	C	106,089	2.215	2,349,780	2.441	2,589,541	239,761
Total			214,828	2.007	4,311,450	2.233	4,796,963	485,513
December	Florida	C	205,311	1.804	3,703,780	2.037	4,182,155	478,375
1996	Southern Co.	C	23,946	2.073	496,380	2.306	552,177	55,797
Total			229,257	1.832	4,200,160	2.065	4,734,332	534,172
January	Florida	C	400,435	1.804	7,223,880	2.009	8,044,772	820,892
1997	Southern Co.	C	35,067	2.089	732,620	2.294	804,505	71,885
Total			435,502	1.827	7,956,500	2.032	8,849,277	892,777
February	Florida	C	262,565	1.804	4,736,690	2.001	5,253,943	517,253
1997	Southern Co.	C	12,014	2.159	259,430	2.356	283,098	23,668
Total			274,580	1.820	4,996,120	2.017	5,537,041	540,921
March	Florida	C	190,136	1.804	3,430,020	1.989	3,781,772	351,752
1997	Southern Co.	C	22,169	2.249	498,630	2.434	539,643	41,013
Total			212,304	1.850	3,928,650	2.035	4,321,415	392,765
Period	Florida	C	1,481,431	1.804	26,724,990	2.019	29,908,912	3,183,922
Total	Southern Co.	C	482,228	2.169	10,461,930	2.403	11,587,264	1,125,334
Total			1,963,659	1.894	37,186,920	2.113	41,496,176	4,309,256

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	APRIL 96 - SEPT 96	Proposed Mid-Course Correction JULY 96 - SEPT 96	OCT 96 - MARCH 97
BASE	$47.46	$47.46	$47.46
FUEL	$20.75	$22.05	$20.41
CONSERVATION	$2.09	$2.09	$2.09
CAPACITY PAYMENT	$4.42	$4.42	$6.21
ENVIRONMENTAL	$0.15	$0.15	$0.17
SUBTOTAL	$74.87	$76.17	$76.34
GROSS RECEIPTS TAX	$0.77	$0.78	$0.78
TOTAL	$75.64	$76.95	$77.12

Company: Florida Power & Light Company

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		OCT - MAR 1993 - 1994 (COLUMN 1)	OCT - MAR 1994 - 1995 (COLUMN 2)	OCT - MAR 1995 - 1996 (COLUMN 3)	OCT - MAR 1996 - 1997 (COLUMN 4)	(COLUMN 2) change from (COLUMN 1)	(COLUMN 3) change from (COLUMN 2)	(COLUMN 4) change from (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	*HEAVY OIL	182,349,625	158,775,167	79,472,605	107,469,520	(12.9)	(50.0)	35.2
2	*LIGHT OIL	16,957	1,004,742	122,299	23,390	5,825.2	(87.8)	(80.9)
3	COAL	44,352,904	43,732,846	56,397,275	47,257,830	(1.4)	29.0	(16.2)
4	GAS	145,061,777	166,515,623	236,228,990	270,201,220	14.8	41.9	14.4
5	NUCLEAR	56,550,343	47,002,153	45,307,764	44,545,480	(16.9)	(3.6)	(1.7)
6	OTHER (ORIMULSION)	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	428,331,606	417,030,531	417,528,933	469,497,540	(2.6)	0.1	12.5
	SYSTEM NET GENERATION (MWH)							
8	*HEAVY OIL	6,806,725	7,416,584	3,342,179	4,203,307	8.9	(54.9)	25.8
9	*LIGHT OIL	231	19,844	1,807	375	8,490.5	(90.9)	(79.3)
10	COAL	2,487,084	2,720,359	3,290,969	2,769,045	9.4	21.0	(15.9)
11	GAS	5,735,854	8,272,046	11,584,471	11,506,558	44.2	40.0	(0.7)
12	NUCLEAR	10,016,782	9,750,442	10,427,491	11,838,090	(2.6)	6.9	13.5
13	OTHER (ORIMULSION)	0		0	0	0.0	0.0	0.0
14	TOTAL (MWH)	25,048,676	28,184,275	28,646,867	30,317,375	12.5	1.6	5.8
	UNITS OF FUEL BURNED							
15	*HEAVY OIL (Bbl)	10,469,253	11,292,603	4,939,440	6,309,829	7.9	(56.3)	27.7
16	*LIGHT OIL (Bbl)	606	32,605	4,284	840	5,280.4	(86.9)	(80.4)
17	COAL (TON)	968,266	1,260,159	1,253,466	1,459,382	30.2	(0.5)	16.4
18	GAS (MCF)	50,398,654	61,259,504	95,891,441	95,087,365	21.6	56.5	(0.8)
19	NUCLEAR (MMBTU)	110,356,760	107,534,485	110,965,066	126,959,392	(2.6)	3.2	14.4
20	OTHER (TONS)	0	0	0		0.0	0.0	0.0
	BTU's BURNED (MMBTU)							
21	*HEAVY OIL	66,679,040	71,902,005	31,362,535	40,352,900	7.8	(56.4)	28.8
22	*LIGHT OIL	3,518	188,534	24,802	4,900	5,262.2	(86.8)	(80.2)
23	COAL	24,106,001	26,541,038	32,701,012	27,685,639	10.1	23.2	(15.3)
24	GAS	50,383,373	61,259,504	95,891,441	95,087,365	21.6	56.5	(0.8)
25	NUCLEAR	110,356,760	107,534,485	110,960,066	126,959,392	(2.6)	3.2	14.4
26	OTHER (ORIMULSION)	0		0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	251,528,690	267,425,566	270,944,856	290,120,196	6.3	1.3	7.1
	GENERATION MIX (%MWH)							
28	*HEAVY OIL	27.18	26.31	11.67	13.86	-	-	-
29	*LIGHT OIL	0.00	0.07	0.01	0.00	-	-	-
30	COAL	9.93	9.65	11.49	9.13	-	-	-
31	GAS	22.90	29.35	40.44	37.95	-	-	-
32	NUCLEAR	39.99	34.61	36.40	39.05	-	-	-
33	OTHER (ORIMULSION)	0.00	0.00	0.00	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	*HEAVY OIL ($/Bbl)	17.4176	14.0601	16.0894	17.0321	(19.3)	14.4	5.9
36	*LIGHT OIL ($/Bbl)	27.9818	30.8156	28.5479	27.8452	10.1	(7.4)	(2.5)
37	COAL ($/TON)	45.8065	34.7042	44.9931	32.3826	(24.2)	29.7	(28.0)
38	GAS ($/MCF)	2.8784	2.7182	2.4636	2.8416	(5.6)	(9.4)	15.4
39	NUCLEAR ($/MMBTU)	0.5124	0.4371	0.4083	0.3509	(14.7)	(6.6)	(14.1)
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	*HEAVY OIL	2.7347	2.2082	2.5340	2.6613	(19.3)	14.8	5.0
42	*LIGHT OIL	4.8228	5.3292	4.9310	4.7735	10.5	(7.5)	(3.2)
43	COAL	1.8399	1.6477	1.7246	1.7069	(10.5)	4.7	(1.0)
44	GAS	2.8792	2.7182	2.4635	2.8416	(5.6)	(9.4)	15.4
45	NUCLEAR	0.5124	0.4371	0.4083	0.3509	(14.7)	(6.6)	(14.1)
46	OTHER (ORIMULSION)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	1.7029	1.5594	1.5410	1.6183	(8.4)	(1.2)	5.0
	BTU BURNED PER KWH (BTU/KWH)							
48	*HEAVY OIL	9,793	9,695	9,384	9,607	(1.0)	(3.2)	2.4
49	*LIGHT OIL	15,221	9,501	13,726	13,067	(37.6)	44.5	(4.8)
50	COAL	9,692	9,756	9,937	9,998	0.7	1.9	0.6
51	GAS	8,784	7,406	8,278	8,264	(15.7)	11.8	(0.2)
52	NUCLEAR	11,017	11,022	10,642	10,725	0.1	(3.5)	0.8
53	OTHER (ORIMULSION)	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	10,042	9,488	9,458	9,569	(5.5)	(0.3)	1.2
	GENERATED FUEL COST PER KWH (¢/KWH)							
55	*HEAVY OIL	2.6782	2.1408	2.3779	2.5568	(20.1)	11.1	7.5
56	*LIGHT OIL	7.3407	5.0632	6.1682	6.2373	(31.0)	21.8	1.1
57	COAL	1.7833	1.6076	1.7137	1.7067	(9.9)	6.6	(0.4)
58	GAS	2.5290	2.0130	2.0392	2.3487	(20.4)	1.3	15.2
59	NUCLEAR	0.5646	0.4818	0.4345	0.3763	(14.7)	(9.8)	(13.4)
60	OTHER (ORIMULSION)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
61	TOTAL (¢/KWH)	1.7100	1.4797	1.4575	1.5486	(13.5)	(1.5)	6.3

*DISTILLATE (Bbls, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS

APPENDIX III

CAPACITY COST RECOVERY

BTB - 4
DOCKET NO 960001-EI
FPL WITNESS:B.T.BIRKETT
EXHIBIT ___________
PAGES 1-8
JUNE 24, 1996

APPENDIX III
CAPACITY COST RECOVERY

TABLE OF CONTENTS

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
OCTOBER 1996 THROUGH SEPTEMBER 1997

	PROJECTED												
	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	TOTAL
1 CAPACITY PAYMENTS TO NON-COGENERATORS	$17,390,315	$17,390,315	$17,390,315	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$207,711,591
2 CAPACITY PAYMENTS TO COGENERATORS	$26,674,718	$26,714,318	$26,714,318	$27,038,910	$27,038,910	$27,038,910	$27,076,818	$27,076,818	$27,090,238	$27,090,238	$27,090,238	$27,090,238	$323,734,672
3 CAPACITY PAYMENTS FOR MISSION SETTLEMENT	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$8,768,730
4 REVENUES FROM CAPACITY SALES	$81,763	$154,682	$81,127	$53,542	$81,227	$219,451	$110,248	$183,477	$194,437	$466,348	$922,136	$371,717	$2,600,155
5 SYSTEM TOTAL (Lines 1+2+3-4)	$44,713,998	$44,680,679	$44,774,234	$44,998,390	$44,970,705	$44,832,481	$44,979,592	$44,906,363	$44,908,823	$44,636,912	$44,481,124	$44,731,543	$537,614,838
6 JURISDICTIONAL % *													97.33111%
7 JURISDICTIONALIZED CAPACITY PAYMENTS													$523,266,489
8 LESS SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
9 FINAL TRUE-UP --overrecovery/(underrecovery) OCTOBER 1995 - MARCH 1996 $28,927,083	EST / ACT TRUE-UP --overrecovery/(underrecovery) APRIL 1996 - SEPTEMBER 1996 $13,378,068												$42,305,151
10 TOTAL (Lines 7+8-9)													$424,015,746
11 REVENUE TAX MULTIPLIER													1.01609
12 TOTAL RECOVERABLE CAPACITY PAYMENTS													$430,838,159

3

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN (MW)	%
FPSC	13,018	97.33111%
FERC	357	2.66889%
TOTAL	13,375	100.00000%

NOTE: BASED ON 1995 ACTUAL DATA

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
OCTOBER 1996 THROUGH SEPTEMBER 1997

Rate Class	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1	60.910%	41,807,749,293	7,835,453	1.083175791	1.067486100	44,629,191,243	8,487,173	53.20547%	60.85589%
GS1	67.794%	4,918,750,249	828,246	1.083175791	1.067486100	5,250,697,520	897,136	6.25971%	6.43277%
GSD1	85.426%	17,893,046,568	2,391,058	1.083103456	1.067479781	19,100,465,432	2,589,763	22.77095%	18.56947%
OS2	93.911%	20,959,421	2,548	1.054413589	1.044406598	21,890,158	2,687	0.02610%	0.01927%
GSLD1/CS1	81.019%	7,270,483,851	1,024,407	1.081662033	1.067196356	7,759,033,872	1,108,062	9.25007%	7.94518%
GSLD2/CS2	82.073%	1,587,641,754	220,825	1.071305922	1.062656678	1,687,118,112	236,571	2.01133%	1.69629%
GSLD3/CS3	80.818%	758,060,128	107,076	1.029467667	1.024433539	776,582,220	110,231	0.92582%	0.79039%
ISST1D	193.881%	2,313,412	136	1.083175791	1.067486100	2,469,535	147	0.00294%	0.00105%
SST1T	48.948%	103,069,640	24,038	1.029467667	1.024433539	105,587,996	24,746	0.12588%	0.17744%
SST1D	146.426%	71,104,739	5,543	1.068724765	1.052872337	74,864,213	5,924	0.08925%	0.04248%
CILC D/CILC G	97.642%	2,528,505,648	295,613	1.075614838	1.063603766	2,689,328,130	317,966	3.20613%	2.27992%
CILC T	99.161%	1,119,271,026	128,852	1.029467667	1.024433539	1,146,618,780	132,649	1.36696%	0.95114%
MET	69.783%	86,779,954	14,196	1.054413589	1.044406598	90,633,557	14,968	0.10805%	0.10733%
OL1/SL1	585.192%	438,580,084	8,556	1.083175791	1.067486100	468,178,143	9,268	0.55815%	0.06645%
SL2	100.003%	73,231,231	8,359	1.083175791	1.067486100	78,173,321	9,054	0.09320%	0.06492%
TOTAL		78,679,547,000	12,894,906			83,880,832,232	13,946,345	100.00%	100.00%

(2) Projected kwh sales for the period October 1996 through September 1997
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 1995 demand losses.
(5) Based on 1995 energy losses.
(6) Col(2) * Col(5)
(7) Col(3) * Col(4)
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
OCTOBER 1996 THROUGH SEPTEMBER 1997

Rate Class	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1	53.20547%	60.85589%	$17,633,036	$242,021,941	$259,654,977	41,807,749,293	-	-	-	0.00621
GS1	6.25971%	6.43277%	$2,074,555	$25,582,918	$27,657,473	4,918,750,249	-	-	-	0.00562
GSD1	22.77095%	18.56947%	$7,546,611	$73,850,181	$81,396,792	17,893,048,568	53.78184%	37,947,945	2.14	-
OS2	0.02610%	0.01927%	$8,650	$76,636	$85,286	20,959,421	-	-	-	0.00407
GSLD1/CS1	9.25007%	7.94518%	$3,065,602	$31,597,724	$34,663,326	7,270,483,851	61.64498%	16,156,331	2.15	-
GSLD2/CS2	2.01133%	1.69629%	$666,583	$6,746,090	$7,412,673	1,587,641,754	64.31296%	3,381,669	2.19	-
GSLD3/CS3	0.92582%	0.79039%	$306,830	$3,143,355	$3,450,185	758,060,128	64.60882%	1,607,271	2.15	-
ISST1D	0.00294%	0.00105%	$974	$4,176	$5,150	2,313,412	86.46049%	3,665	**	-
SST1T	0.12588%	0.17744%	$41,718	$705,673	$747,391	103,069,640	10.65279%	1,325,393	**	-
SST1D	0.08925%	0.04248%	$29,579	$168,942	$198,521	71,104,739	79.38012%	122,705	**	-
CILC D/CILC G	3.20613%	2.27992%	$1,062,556	$9,067,168	$10,129,724	2,528,505,648	75.60946%	4,581,049	2.21	-
CILC T	1.36696%	0.95114%	$453,030	$3,782,653	$4,235,683	1,119,271,028	79.76567%	1,922,190	2.20	-
MET	0.10805%	0.10733%	$35,809	$426,848	$462,657	86,779,954	59.38085%	200,194	2.31	-
OL1/SL1	0.55815%	0.06645%	$184,979	$264,269	$449,248	438,580,084	-	-	-	0.00102
SL2	0.09320%	0.06492%	$30,888	$258,185	$289,073	73,231,231	-	-	-	0.00395
TOTAL			$33,141,400	$397,696,759	$430,838,159	78,679,547,000		67,248,412		

Note: There are currently no customers taking service on Schedule ISST1(T). Should any customer begin taking service on this schedule during the period, they will be billed using the ISST(D) Factor.

(1) Obtained from Document No. 2
(2) Obtained from Document No. 2
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period October 1996 through September 1997
(7) (1995 kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730) For GSD-1, only 83.265% of KW are billed due to 10 KW exemption
(9) Col (5) / (8)
(10) Col (5) / (6)

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Reservation Demand Charge (RDC) = $\frac{\text{(Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4)}}{\text{12 months}}$

Sum of Daily Demand Charge (SDD) = $\frac{\text{(Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4)}}{\text{12 months}}$

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1 (D)	$0.28	$0.13
SST1 (T)	$0.27	$0.13
SST1 (D)	$0.28	$0.13

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL 1996 THROUGH SEPTEMBER 1996

	(1) ACTUAL APRIL	(2) ACTUAL MAY	(3) REVISED PROJECTIONS JUNE	(4) REVISED PROJECTIONS JULY	(5) REVISED PROJECTIONS AUGUST	(6) REVISED PROJECTIONS SEPTEMBER	(7) TOTAL
1. Unit Power (UPS) Capacity Charges	$3,974,296	$10,130,954	$10,824,720	$10,824,720	$10,824,720	$10,824,720	$57,304,130
2. SJRPP Capacity Charges	6,320,425	6,341,737	6,565,595	6,565,595	6,565,595	6,565,595	38,924,543
3. Qualifying Facilities (QF) Capacity Charges	23,646,489	22,981,858	26,674,718	26,674,718	26,674,718	26,674,718	153,327,219
4. Short-term Capacity Purchases	0	0	0	0	0	0	0
5. Revenues from Capacity Sales	(27,353)	(878,961)	(190,625)	(457,204)	(609,937)	(364,429)	(2,528,509)
6. Total Company Capacity Charges	33,813,858	38,575,588	43,874,408	43,607,829	43,455,096	43,700,604	247,027,383
7. Jurisdictional Separation Factor (a)	97.25530%	97.25530%	97.25530%	97.25530%	97.25530%	97.25530%	n/a
8. Jurisdictional Capacity Charges	32,885,769	37,516,804	42,670,187	42,410,925	42,262,384	42,501,154	240,247,223
9. Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(28,472,796)
10. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$28,140,303	$32,771,338	$37,924,721	$37,665,459	$37,516,918	$37,755,688	$211,774,427
11. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$24,332,448	$24,452,663	$26,156,692	$28,914,103	$28,815,850	$28,063,637	$160,735,393
12. Prior Period True-up Provision	10,424,404	10,424,404	10,424,404	10,424,404	10,424,404	10,424,404	62,546,424
13. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$34,756,852	$34,877,067	$36,581,096	$39,338,507	$39,240,254	$38,488,041	$223,281,817
14. True-up Provision for Month - Over/(Under) Recovery (Line 13 - Line 10)	$6,616,549	$2,105,729	($1,343,625)	$1,673,048	$1,723,336	$732,353	$11,507,390
15. Interest Provision for Month	406,795	377,609	334,113	289,448	251,483	211,230	1,870,678
16. True-up & Interest Provision Begining of Month - Over/(Under) Recovery	62,546,424	59,145,364	51,204,297	39,770,382	31,308,474	22,858,889	62,546,424
17. Deferred True-up - Over/(Under) Recovery	28,927,083	28,927,083	28,927,083	28,927,083	28,927,083	28,927,083	28,927,083
18. Prior Period True-up Provision - Collected/(Refunded) this Month	(10,424,404)	(10,424,404)	(10,424,404)	(10,424,404)	(10,424,404)	(10,424,404)	(62,546,424)
19. End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	$88,072,447	$80,131,380	$68,697,465	$60,235,557	$51,785,972	$42,305,151	$42,305,151

Notes: (a) Per B. T. Birkett's Testimony, Appendix IV, Page 3, Line 5, Docket No. 960001-EI, filed January 22, 1996.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, issued September 6, 1994 in Docket No. 940001-EI.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL INTEREST PROVISION
FOR THE PERIOD APRIL 1996 THROUGH SEPTEMBER 1996

	(1) ACTUAL APRIL	(2) ACTUAL MAY	(3) REVISED PROJECTIONS JUNE	(4) REVISED PROJECTIONS JULY	(5) REVISED PROJECTIONS AUGUST	(6) REVISED PROJECTIONS SEPTEMBER	(7) TOTAL
1. Beginning True-up Amount	$91,473,507	$88,072,447	$80,131,380	$68,697,465	$60,235,557	$51,785,972	n/a
2. Ending True-up Amount Before Interest	87,665,652	79,753,771	68,363,351	59,946,109	51,534,489	42,093,921	n/a
3. Total Beginning & Ending True-up Amount (Lines 1 + 2)	179,139,159	167,826,218	148,494,732	128,643,573	111,770,046	93,879,893	n/a
4. Average True-up Amount (50 % of Line 3)	$89,569,579	$83,913,109	$74,247,366	$64,321,787	$55,885,023	$46,939,946	n/a
5. Interest Rate - First day of Reporting Business Month	0.05500	0.05400	0.05400	0.05400	0.05400	0.05400	n/a
6. Interest Rate - First day of Subsequent Business Month	0.05400	0.05400	0.05400	0.05400	0.05400	0.05400	n/a
7. Total Interest Rate (Lines 5 + 6)	0.10900000	0.10800000	0.10800000	0.10800000	0.10800000	0.10800000	n/a
8. Average Interest Rate (50 % of Line 7)	0.05450000	0.05400000	0.05400000	0.05400000	0.05400000	0.05400000	n/a
9. Monthly Average Interest Rate (1/12 of Line 8)	0.00454167	0.00450000	0.00450000	0.00450000	0.00450000	0.00450000	n/a
10. Interest Provision for the Month (Line 4 X Line 9)	$406,795	$377,609	$334,113	$289,448	$251,483	$211,230	$1,870,678

NOTE: Columns and rows may not add due to rounding.

FOR THE PERIOD APRIL 1996 THROUGH SEPTEMBER 1996

	(1) ESTIMATED/ ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE (1)-(2)	(4) PERCENTAGE CHANGE (3)/(2)
1. Unit Power (UPS) Capacity Charges	$57,304,130	$67,658,640	($10,354,510)	-15.30%
2. SJRPP Capacity Charges	38,924,543	39,443,364	(518,821)	-1.32%
3. Qualifying Facilities (QF) Capacity Charges	153,327,219	150,874,748	2,452,471	1.63%
4. Short-term Capacity Purchases	0	0	0	n/a
5. Revenues from Capacity Sales	(2,528,509)	(1,910,161)	(618,348)	32.37%
6. Total Company Capacity Charges	247,027,383	256,066,591	(9,039,208)	-3.53%
7. Jurisdictional Separation Factor	97.25530%	97.25530%	0.00%	0.00%
8. Jurisdictional Capacity Charges	240,247,222	249,038,331	(8,791,109)	-3.53%
9. Capacity related amounts included in Base Rates (FPSC Portion Only)	(28,472,796)	(28,472,796)	0	0.00%
10. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$211,774,427	$220,565,535	($8,791,108)	-3.99%
11. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$160,735,393	$158,019,111	$2,716,282	1.72%
12. Prior Period True-up Provision	62,546,424	62,546,424	0	n/a
13. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$223,281,817	$220,565,535	$2,716,282	1.23%
14. True-up Provision - Over/(Under) Recovery (Line 13 - Line 10)	$11,507,390	$0	$11,507,390	n/a
15. Interest Provision	1,870,678	0	1,870,678	n/a
16. True-up & Interest Provision Begining of Month - Over/(Under) Recovery	62,546,424	62,546,424	0	0.00%
17. Deferred True-up - Over/(Under) Recovery	28,927,083	0	28,927,083	n/a
18. Prior Period True-up Provision - Collected/(Refunded)	(62,546,424)	(62,546,424)	0	0.00%
19. End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	$42,305,151	$0	$42,305,151	n/a

Notes: (a) Per Appendix IV, page 3, filed January 22, 1996, in Docket No. 960001-EI, and approved at the February 1996 hearings, FPSC Order No. PSC-96-0353-FOF-EI.

8