BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 970001-EI
FLORIDA POWER & LIGHT COMPANY

JUNE 23, 1997

IN RE: LEVELIZED FUEL COST RECOVERY
OCTOBER 1997 THROUGH MARCH 1998
AND
CAPACITY COST RECOVERY
OCTOBER 1997 THROUGH SEPTEMBER 1998

TESTIMONY & EXHIBITS OF:

R. SILVA
R. L. WADE
M. VILLAR
K. M. DUBIN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENE SILVA

DOCKET NO. 970001-EI

June 23, 1997

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 April through September,1997. In addition, my testimony describes the circumstances regarding FPL's request to begin recovery, through the Capacity Cost Recovery Clause, of approximately $4.7 million per year associated with capacity payments to be made to Jacksonville Electric Authority (JEA) during the "St. Johns River Power Park energy suspension period".

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, 1997 through March, 1998 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 price 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 1998 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 1998 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 moderate increase in OPEC production, in part due to the resumption of small quantities of Iraqi exports .

Based on these factors crude oil prices, and consequently heavy fuel oil prices, for the October, 1997 through March, 1998 period will be only slightly higher than at present.

Q. **What is the projected relationship between heavy fuel oil and crude oil prices during the October, 1997 through March, 1998**

period?

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 72% 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, 1997 through March, 1998 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, 1997 through March, 1998.

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.

In the case of SJRPP, FPL began to blend petroleum coke with the coal in order to reduce fuel costs, beginning in the spring of 1997. It is anticipated that petroleum coke will represent 15% of the fuel blend at SJRPP. The lower price of petroleum coke is reflected in the weighted average price of fuel delivered to SJRPP.

Q. Please provide FPL's projection for the dispatch cost of coal for

the October, 1997 through March, 1998 period.

A. FPL's projected system average dispatch cost of coal, shown on page 5 of Appendix I, is about $1.53 per million BTU, delivered to plant.

Q. What are the factors that can affect FPL's natural gas prices during the October, 1997 through March, 1998 period?

A. In general, the key factors are (1) domestic natural gas demand and supply, (2) natural gas imports, (3) heavy fuel oil prices and (4) the terms of FPL's gas supply and transportation contracts.

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. The quantity of natural gas in inventory in April, 1997 - the start of the gas "injection" season - while lower than average, was significantly higher than in April, 1996.

It is projected that by the end of October the inventory level will be adequate to meet winter (1997-1998) demand for natural gas. Consequently, gas prices for the October, 1997 through March, 1998 period are projected to be lower than during the same period a year earlier.

Q. What are the factors that affect the availability of natural gas to FPL during the October, 1997 through March, 1998 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 during this period, 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 245,000 and 255,000 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, 1997 through

March, 1998 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 calculated by the POWRSYM model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to POWRSYM for this calculation. The heat rate equations and efficiency factors are updated as appropriate, based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, or results of performance tests.

Q. Are you providing the outage factors projected for the period October, 1997 through March, 1998?

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 historical unplanned outage factor of each generating unit 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, 1997 through March, 1998 period.

Q. Please describe significant planned outages for the October, 1997 through March, 1998 period.

A. Planned outages at our nuclear units are the most significant in relation to Fuel Cost Recovery. Turkey Point Unit No.4 is scheduled to be out of service for refueling beginning on September 8, 1997 and until October 18, 1997, or eighteen days during the projected period. St. Lucie Unit No.1 will be out of service for refueling beginning on October 20, 1997 and until January 3, 1998, or seventy-five 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 April through September, 1997 period?

A. Yes. Net Summer Continuous Capability (NSCC) at Pt. Everglades

Unit No.4 will increase by 21 MW, from 385 MW to 406 MW, while its Summer Peaking Capability (SPC) will increase by 16 MW, from 395 MW to 411 MW. This change had been previously projected to occur during the April through September, 1997 period.

Q. Are you providing the projected interchange and purchased power transactions forecasted for October, 1997 to March, 1998?

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, 1997 to March, 1998 period.**

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 913 MW from October, 1997 through March, 1998. 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 1,561,795 MWH of UPS Energy at a cost of $29,129,990. In addition, we project the purchase of 1.088,327 MWH of UPS Replacement energy (Schedule R) at a cost of $17,915,970. The total UPS Energy plus Schedule R projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of the St. Johns River Power Park generation are projected to be 1,388,436 MWH for the period at an energy cost of $20,691,410. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, we project purchases of 261,495 MWH at a cost of $958,900. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, we project that purchases from Qualifying Facilities for the period will provide

3,625,783 MWH at a cost to FPL of $66,825,038.

Q. How were energy costs related to purchases from Qualifying Facilities developed?

A. For those contracts that entitle FPL to purchase "as-available" energy we used FPL's fuel price forecasts as inputs to the POWRSYM model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanism prescribed in the contract is used to project monthly energy costs.

Q. Have you projected Schedule A/AF - Emergency Interchange Transactions?

A. No purchases or sales under Schedule A/AF have been projected since it is not practical to estimate emergency transactions.

Q. Have you projected Schedule B/BF - Short-Term Firm Interchange Transactions?

A. No commitment for such transactions had been made when projections were developed. Therefore, we have estimated that no Schedule BF sales or Schedule B purchases would be made in the projected period.

Q. Please describe the method used to forecast the Economy Transactions.

A. The quantity of economy sales and purchase transactions are projected based upon historic transaction levels, adjusted to remove non-recurring factors.

Q. What are the forecasted amounts and costs of Economy energy sales?

A. We have projected 814,436 MWH of Economy energy sales for the period. The projected fuel cost related to these sales is $19,169,883. The projected transaction revenue from the sales is $24,235,826. Eighty percent of the gain for Schedule C is $4,052,754 and is credited to our customers.

Q. In what document are the fuel costs of economy energy sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWH of energy and total dollars for fuel adjustment. The 80% of gain is also provided on

Schedule E6 of Appendix II.

Q. **What are the forecasted amounts and costs of Economy energy purchases for the October, 1997 to March, 1998 period?**

A. The costs of these purchases are shown on Schedule E9 of Appendix II. For the period FPL projects it will purchase a total of 2,392,872 MWH at a cost of $45,368,580. If generated, we estimate that this energy would cost $52,804,756. Therefore, these purchases are projected to result in savings of $7,436,176.

Q. **What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?**

A. We project the sale of 153,043 MWH of energy at a cost of $621,700. These projections are shown on Schedule E6 of Appendix II.

Q. **Are you presenting testimony related to the Capacity Cost Recovery clause?**

A. Yes. Ms. Korel M. Dubin has filed testimony in which she addresses FPL's request that it be authorized to collect, during the next seventeen (17) years, approximately $4.7 million per year associated with future capacity payments to be made to JEA during the SJRPP energy suspension period. My testimony describes the circumstances that underlie FPL's request.

Q. **Why does FPL propose to recover, between 1998 and 2014, capacity costs to be paid to JEA between 2015 and 2020?**

A. Because there is a mismatch between the period over which FPL currently anticipates it will continue to receive energy from JEA's ownership share of SJRPP, and the period over which FPL is contractually required to make annual capacity payments to JEA.

Q. **Please explain this mismatch between capacity and energy under the contract with JEA.**

A. FPL makes capacity payments to JEA at a rate necessary to pay off, by the year 2020, bonds issued by JEA to finance SJRPP. The magnitude of the annual capacity payment is not related to the quantity of energy FPL receives each year. In fact, since SJRPP provides a low-cost source of energy, the plant runs as much as possible, and FPL takes as much of the plant's energy as it can each year, while the capacity payment remains unaffected.

Q. **Why does this mismatch create a concern?**

A. Because the total quantity of energy FPL can take from JEA's ownership share of SJRPP through the year 2020 is limited to 80,534,332 MWh. FPL is taking as much SJRPP energy as possible currently, and we project that the energy limit will be reached in 2015. Thereafter FPL will, consistent with the contract, continue making capacity payments through 2020, but would receive no energy from JEA's share of SJRPP ("SJRPP energy suspension").

Q. How was this energy limit established?

A. An Internal Revenue Service (IRS) ruling, which established the tax-exempt status of the municipal bonds used to finance JEA's ownership interest in SJRPP, stipulates that FPL shall not receive more than twenty-five percent (25%) of the namplate capacity of JEA's ownership share of the plant over the life of the bonds. Under FPL's contract with JEA, FPL will purchase 37.5% of energy produced by JEA's share of the plant, based on a projected plant capacity factor of approximately 67%. This is equivalent to 25% of the plant's total capability.

Q. Has SJRPP operated at the assumed 67% capacity factor?

A. The plant has operated at a 88.2% capacity factor and as a result FPL has received more low-cost energy during the first ten years of operation than had been originally estimated. We project that the plant will operate at an average capacity factor of 92% between 1998 and 2014. At that rate, the energy limit of 80,534,332 MWh imposed by the IRS ruling will be reached in 2015.

Q. **Why doesn't FPL reduce the quantity of energy purchased from JEA's share of SJRPP so that the energy limit would not be reached until the bonds are paid?**

A. Because we would have to replace the energy not taken from SJRPP with more expensive purchases or FPL generation, and as a result our customers' costs would increase. In fact, our analysis shows that operating SJRPP at a 67% capacity factor in order to reduce the annual quantity of SJRPP energy purchases would increase energy costs by about $128 million on a net present value basis between 1998 and 2020. The net present value of the amount FPL is requesting to collect is approximately $40 million.

Q. **Would you please summarize your testimony?**

A. Yes. In my testimony I have presented FPL's fuel price projections for the fuel cost recovery period of October, 1997 through March,

1998. In addition, I have presented FPL's projections for generating unit heat rates and availabilities, and the quantities and costs of interchange and other power transactions for the same period. These projections were based on the best information available to FPL, and were used as inputs to POWRSYM in developing the projected Fuel Cost Recovery Factor for the October, 1997 through March, 1998 period.

My testimony also describes the circumstances underlying FPL's request to begin to recover currently about $4.7 million per year in future SJRPP capacity costs through the Capacity Clause.

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. 970001-EI

June 23, 1997

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. **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 1997 through March 1998.

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 O~tober 1997 through March 1998.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period October 1997 through March 1998.

A. FPL projects the nuclear units will produce 114,468,963 MBTU of energy at a cost of $0.333 per MMBTU, excluding spent fuel disposal costs for the period October 1997 through March 1998. 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 1997 through March 1998 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 U.S. 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 1997 through March 1998 and what is the basis for FPL's projection.

A. FPL's projection of $5.42M for D&D costs to be paid during the period October 1997 through March 1998 is included on Schedule E-2 of Appendix II.

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 DOE for final disposal of spent nuclear fuel. FPL, along with a number of electric utilities, has filed suit against DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. A July 23, 1996, ruling by the U.S. Court of Appeals for the District of Columbia said that DOE is required by the Nuclear Waste Policy Act to take title and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998. DOE declined to seek further review of the decision, which was remanded to DOE for further proceedings. On December 17, 1996, DOE advised the electric utilities that it would not begin to dispose of spent nuclear fuel by the unconditional deadline.

In response to DOE's letter, FPL, other electric utilities, and state utility commissions filed suit on January 31, 1997 in the U.S. Court of Appeals for the District of Columbia requesting that the court authorize the utilities to suspend payments into the Nuclear Waste Fund (NWF) until DOE performs on its unconditional obligation to take title to and dispose of spent nuclear fuel.

On May 7, 1997, the utilities filed a petition for a writ of mandamus that (1) DOE comply with its statutory obligation and begin disposing of spent nuclear fuel by January 31, 1998 or in the alternative, direct DOE to develop a program that will enable the agency to begin disposing of spent nuclear fuel by January 31, 1998; (2) declaring that the utilities are relieved of the obligation to pay into the NWF and are authorized to place NWF collections into escrow until DOE disposes of the spent nuclear fuel; (3) prohibiting DOE from suspending the contracts with the utilities or from taking any other adverse action under the contracts; and (4) declaring that the suspension of fee payments will not adversely affect the utilities as to timing, manner, or further cost disposal entitlements by reason of such suspension of fee payments. DOE must file a response to the petition on June 6, 1997. The utilities may then reply to DOE's response ten days thereafter.

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. FPL's 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 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 Year 1993. FPL has been making such payments. Therefore, D&D should not have been included in the price charged by DOE for deliveries during Fiscal Year 1993, and the price should have been reduced accordingly. FPL filed a claim with the DOE 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. On October 11, 1996, FPL, along with five other U.S. utilities and one foreign entity, appealed DOE's rejection of the Fiscal Year 1993 overcharge claim with the U.S. Court of Federal Claims.

On December 12, 1996, the Court of Federal Claims granted the unopposed motion of all parties to suspend the overcharge proceeding pending the outcome of an appeal to the U.S. Court of Appeals for the Federal Circuit in Barseback Kraft AB v. United States, where the appellants are seeking to recover overcharges for uranium enrichment services under identical contract provisions to those at issue in FPL's overcharge claim. Oral argument was held in the Barseback case on May 7, 1997, and a decision could be issued during the summer of 1997. FPL will reevaluate the validity of its overcharge claim upon issuance of a final decision in the Barseback case.

Meanwhile, in a related case, Yankee Atomic Electric Company had been challenging the legality of the United States to impose the D&D fees. On May 6, 1997, a panel of the U.S. Court of Appeals for the Federal Circuit held that the D&D special assessment was lawful under the Energy Policy Act. United States v. Yankee Atomic Electric Co. A lower court had ruled that the D&D special assessment was unlawful. Yankee has until June 20, 1997 to determine whether to seek review from the full panel of the Federal Circuit. FPL will continue to follow this case and will take actions, as appropriate, consistent with the outcome of the appeal.

Q. **Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

TESTIMONY OF MARIO VILLAR

DOCKET NO. 970001-EI

June 23, 1997

Q. Please state your name and business address.

A. My name is Mario Villar and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Wholesale Services in the Power Delivery Business Unit.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science in Electrical Engineering and a Juris Doctor degree, both from the University of Miami. I have also completed the University of Florida's/Florida Power & Light Company's Nuclear Power Engineering Program (a four month, full-time, course of study in Nuclear Reactor Engineering, Technology, and Balance of Plant) and Columbia University's Executive Program in Business Administration. I am a member of the Florida Bar, the Federal Energy Bar Association and the Institute of Electrical and Electronics Engineers.

Additionally, I have completed numerous technical and management courses during my career at FPL.

I joined FPL in 1973 as an engineer in the Distribution Engineering department. In 1976, I transferred to the Nuclear Licensing department as Licensing Engineer for St. Lucie Nuclear Unit No. 2. In 1980, I joined the System Planning department as Senior Engineer working on special projects (e.g., major generation and transmission facilities; proposed regulations). In 1982, I joined the Governmental Affairs department as an Issues Advisor on State and Federal legislative and regulatory matters. In 1984, I was promoted to Federal Regulatory Representative to represent the Company's interests before regulatory, legislative and executive branch agencies, and trade associations in Washington, D.C. In 1989, I joined the Regulatory Affairs department as State Regulatory Representative. In 1991, I became Manager of Regulatory Issues and Policies, working on various State and Federal regulatory matters. In 1993, I joined the Bulk Power Markets department as Manager of Technical Services and Regulatory Support. In 1996, I became Manager of Wholesale Services. In that capacity, I am responsible for requirements and non-utility generation (QF) contracts and for Power Delivery's contract and tariff filings before the Federal Energy Regulatory Commission, including those related to FERC Orders 888 and 888A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address issues raised at the Prehearing Conference of February 5, 1997, and deferred by Order No. PSC-97-0180-PHO-EI, in connection with FERC's Order 888 requirement that investor owned utilities include the cost of transmission when making Schedule C sales.

Q. How should transmission costs be accounted for when determining the transaction price of an economy, Schedule C, broker transaction between two directly interconnected utilities?

A. Transmission costs should be accounted for by adjusting the buyer's costs in the Broker matching algorithm just like it is done for transactions between non-directly interconnected utilities. FPL proposes to base its customers' Fuel Clause revenues and expenses on the same methodology that has been in existence for years. That methodology results in revenue credits through the Fuel Clause based on the delivered price of the generation quoted on the Broker. Under FERC's new rules for offsystem sales that delivered price now includes transmission costs.

Prior to FERC Order 888, transmission costs where not included in the Broker price quote for two directly interconnected utilities (e.g., FPL and FPC). Transmission costs where only considered in the matching of two non-directly interconnected utilities (e.g., FPL and Tallahassee) by adjusting the buyer's quote by the transmission charge of the intervening utility. As a result of FERC Order 888, utilities are now required to charge themselves for the use of their own transmission when making offsystem sales. The rationale behind this requirement is so that transmitting utilities do not have a competitive advantage over others that must use the transmitting utilities' transmission system for making sales (i.e., they treat themselves comparably). Therefore, the costs of transmission are to be included for Schedule C broker sales.

Since the philosophy of the Broker has been that the cost of generation quoted on the Broker should reflect the delivered price of that generation (e.g., Broker quotes have for years been based on the cost of generation at the point of delivery to another system), FPL is treating its sales to directly interconnected utilities in the same manner that all other Broker transactions are treated (or following FERC's principles - in a comparable manner). That is, matches for FPL's Schedule C sales are based on the delivered price of its generation to the delivery point with the directly interconnected utility. That delivered price includes the charge for FPL's transmission pursuant to FPL's FERC filed transmission tariff. Through this methodology FPL's Broker sales are treated the same as Broker sales by other users of FPL's transmission system.

Q. **If the cost of transmission is used to determine the transaction price of an economy, Schedule C, broker transaction between two directly**

interconnected utilities, how should the cost of this transaction be recovered?

A. As described in more detail below, FPL proposes to flow through the fuel clause for the benefit of its customers the revenues received for transmission service when making Schedule C sales. In order to show the effect of Order 888 on Schedule C purchases and sales on the Broker, I have attached to my testimony two exhibits (Exhibits MV-1 and MV-2) illustrating how FPL's delivered price of product methodology treats a Broker transaction between two directly interconnected utilities both before and after Order 888. Exhibit MV-1 shows the purchase side of Schedule C Broker transactions for directly interconnected utilities. Exhibit MV-2 shows the sales side of such transactions. For illustrative purposes it is assumed that the buying utility's cost of running its own generation to supply the next Mw would be \$30/Mw. The selling utility's incremental cost of generation for sale is \$20/Mw. Transmission charges are assumed to be \$3/Mw.

<u>Schedule C Purchases</u>

Under the process in effect prior to Order 888 and assuming a Broker match between these two utilities, a transaction would take place between them at \$25/Mw ((\$30+\$20)/2). The transaction price and the resulting customer charge by the purchasing utility (its regulatory treatment) are shown on Exhibit MV-1 under the headings "BEFORE" (FERC Order 888).

After Order 888 transmission costs need to be included in a utility's economy sales. The effects of the Order are shown on Exhibit MV-1 under the headings "AFTER". The Broker computer matching would account for these transmission charges by adjusting the buyer's quote by the transmission charge of $3. The resulting sale would take place at a price of $23.50 (($30-$3+20)/2). The way the Broker works the buyer in a transaction receives a separate invoice for transmission, thus the total cost to the purchaser is $26.50 ($23.50 + $3 transmission charge). This total cost is reflected in the regulatory treatment for recovery of these charges in Exhibit MV-1.

Schedule C Sales

Exhibit MV-2 shows the sales side of a Broker transaction between the same two utilities. Prior to Order 888, the transaction would take place at the same price of $25 discussed before since there was no charge for transmission. The seller would receive revenues of $25 and incur costs of $20 for a gain of $5. The regulatory treatment of this gain for both customers and seller are shown in Exhibit MV-2 under the headings "BEFORE". In this example, $4 (80% of the gain) would be credited to customers through the Fuel Clause and $1 (20%) would be retained by Seller.

As described above, after Order 888 the transaction price would be $23.50 and the Seller would separately receive $3 for transmission. FPL proposes to credit the transmission revenues for these transactions to its customers through the Fuel Clause (i.e., FPL does not propose to either retain these revenues "above the line" as "other revenues", or to treat them as part of the "gain" on the sale and retain 20%). This is shown in the "AFTER" column in Exhibit MV-2 where the $3 for transmission are treated as a direct credit and 80% ($2.80) of the $3.50 gain is also credited to customers. In this case the seller would retain $0.70 (20%) of the $3.50 gain.

Q. How should transmission costs be accounted for when determining the transaction price of an economy, Schedule C, broker transaction that requires wheeling between two non-directly interconnected utilities?

A. FPL proposes no change in the manner in which transmission costs are accounted for by the Broker for transactions between non-directly interconnected utilities. Since about 1981 the Broker has treated the transmission costs of the intervening utility as part of the costs incurred to deliver the generation to the buyer. Accordingly, the Broker adjusts the buyer's quote to recognize these costs. The adjustment is done in the same manner described in Exhibits MV-1 and MV-2 for "AFTER" transactions. The introduction of the transmission cost of the intervening utility does result in a change in the transaction price from that shown in Exhibits MV-1 and MV-2, however, the dollar difference between the total cost of the transactions before and after (Order 888) is the same as that presented for two directly interconnected utilities. As has always been the case with the transmission charge by the intervening utility, the transmission revenues received by such utility are not part of that utility's Fuel Clause filing as it did not have a Schedule C transaction.

Q. If the cost of transmission is used to determine the transaction price of an economy, Schedule C, broker transaction between two non-directly interconnected utilities, how should the cost of this transaction be recovered?

A. FPL again proposes no change in the current regulatory treatment of these costs. Transmission costs paid to intervening utilities are part of the total cost of Schedule C transactions and should continue to be recovered through the Fuel Clause.

Q. Does this conclude your testimony?

A. Yes, it does.

DELIVERED PRICE OF PRODUCT METHODOLOGY (FPL)
SCHEDULE C PURCHASE

TRANSACTION COMPONENTS	FERC ORDER 888 BEFORE	FERC ORDER 888 AFTER	
Seller's Cost	$ 20.00	$ 20.00	
Buyer's Incremental Cost	$ 30.00	$ 30.00	
Transmission Rate	$ -	$ 3.00	(Buyer receives a separate invoice for transmission)
Buyer's Incremental Cost minus transmission	$ -	$ 27.00	
Agree to split the difference	$ 25.00	$ 23.50	

REGULATORY TREATMENT

BEFORE Flowthrough to: Customers	AFTER Flowthrough to: Customers	
$ (25.00)	$ (23.50)	Fuel Cost charged to customers through Fuel Clause
$ -	$ (3.00)	Transmission charged to customers through Fuel Clause
$ (25.00)	$ (26.50)	Total Cost of Transaction

MV-1
DOCKET NO. 970001-EI
FPL WITNESS: M.VILLAR
EXHIBIT NO. ______
PAGE 1 OF 1
JUNE 23, 1997

DELIVERED PRICE OF PRODUCT METHODOLOGY (FPL)
SCHEDULE C SALE

TRANSACTION COMPONENTS	FERC ORDER 888 BEFORE	FERC ORDER 888 AFTER	
Seller's Cost	$ 20.00	$ 20.00	
Buyer's Incremental Cost	$ 30.00	$ 30.00	
Transmission Rate	$ -	$ 3.00	(Seller bills transmission charge of $3.00 separately)
Buyer's Incremental Cost minus transmission	$ -	$ 27.00	
Agree to split the difference	$ 25.00	$ 23.50	
Broker Price	$ 25.00	$ 23.50	
Seller's Fuel Cost	$ 20.00	$ 20.00	
Gain	$ 5.00	$ 3.50	

REGULATORY TREATMENT

BEFORE Flowthrough to: Customers	BEFORE Flowthrough to: Seller	AFTER Flowthrough to: Customers	AFTER Flowthrough to: Seller	
$ 20.00	$ -	$ 20.00	$ -	Revenue credited to customers through Fuel Clause
$ (20.00)		$ (20.00)		Seller's $20.00 in fuel cost is also charged to the customers so this is a wash
$ -	$ -	$ 3.00	$ -	Transmission Revenue credited to customers through Fuel Clause
				Gain ($3.50) is split 80% to customers via the Fuel Clause and 20% to Seller
$ 4.00	$ -	$ 2.80	$ -	80% credited to customers through the Fuel Clause
$ -	$ 1.00	$ -	$ 0.70	20% to Seller
$ 4.00	$ 1.00	$ 5.80	$ 0.70	

MV-2
DOCKET NO. 970001-EI
FPL WITNESS: M.VILLAR
EXHIBIT NO. ______
PAGE 1 OF 1
JUNE 23, 1997

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 970001-EI

June 23, 1997

Q. Please state your name and address.

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

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

A. I am employed by Florida Power & Light Company (FPL) as Principal Rate Analyst in the Rates and Tariff Administration Department.

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 1997 through March 1998 and the capacity payment factors for the Company's rate schedules for the period October 1997 through September 1998. 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. I am also providing projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual generation mix and fuel prices.

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) for the period April 1997 through September 1997 and the Capacity Cost Recovery Clause(CCR) for the period October 1996 through September 1997.

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 1997 and May 1997 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. 1.643¢ per kWh. Schedule El, 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 1997 through March 1998 and also the six-month levelized fuel factor for the period.

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

A. Yes. Schedule E1-D, Page 8 of Appendix II provides a six-month levelized fuel factor of 1.734¢ per kWh on-peak and 1.607¢ 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 overrecovery for the April 1997 through September 1997 period amounts to $14,618,648. This estimated/actual overrecovery for the April 1997 through September 1997 period plus the final overrecovery of $13,141,163 for the October 1996 through March 1997 period results in a total overrecovery of $27,759,811. This amount, divided by the projected retail sales of 37,770,170 MWH for October 1997 through March 1998 results in a decrease of 0.0735¢ per kWh before applicable revenue taxes. In his testimony for the Generating Performance Incentive Factor, FPL Witness R. Silva calculated a reward of $5,801,940 for the period ending September 1996, one half ($2,900,970) of which is being applied to the October 1997 through March 1998 period. This $2,900,970 divided by the projected retail sales of 37,770,170 MWH during the projected period, results in an increase of 0.0077¢ 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 1997 through September 1997 is an overrecovery, including interest, of $14,618,648 (Column 7, lines C7 plus C8). This amount, when combined with the Final True-up overrecovery of $13,141,163 (Column 7, line C9a) deferred from the period October 1996 through March 1997, presented in my Final True-up testimony filed on May 20, 1997, results in the End of Period overrecovery of $27,759,811 (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 Provision (lines C4 through C10) for this period, and the End of Period True-up amount (line C11).

The data for April 1997 and May 1997, columns (1) and (2) reflects the actual results of operations and the data for June 1997 through September 1997, 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 1997 through September 1997 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 $26.4 million or a 3.1% decrease. This variance is mainly due to an approximate $12.0 million decrease in the Fuel Cost of System Net Generation as shown on line A1a and an approximate $12 million decrease in Energy Payments to Qualifying Facilities as shown on line A3b.

The decrease in the Fuel Cost of System Net Generation was primarily due to a reduction in natural gas and heavy oil prices due to milder than anticipated weather. The decrease in Energy Payments to Qualifying Facilities was primarily due to lower than expected deliveries from Indiantown Cogeneration Limited (ICL), Cedar Bay and Florida Crushed Stone contracts.

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. **Several issues were raised at the Prehearing Conference on February 5, 1997, and deferred by Order No. PSC-97-0180-PHO-EI, in connection with FERC's Order 888 requirement that investor**

owned utilities include the cost of transmission when making Schedule C sales. How should these transmission costs be recovered?

A. FPL proposes to include the transmission costs of Schedule C in the calculation of the Fuel Cost Recovery Clause. These costs are to be included in the calculation of Economy Sales as reported monthly on Schedules A6 and A6a. This issue is addressed in greater detail in the testimony of FPL witness, Mario Villar.

CAPACITY PAYMENT RECOVERY CLAUSE

Q. Please describe Page 3 of Appendix III.

A. Page 3 of Appendix III provides a summary of the requested capacity payments for the projected period of October 1997 through September 1998. Total recoverable capacity payments amount to $480,405,069 (line 12), and include payments of $207,724,137 to non-cogenerators (line1), payments of $345,135,975 to cogenerators (line 2), $3,467,177 of Mission Settlement payments (line 3) and $4,700,000 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4a) which is explained later in my testimony. This amount is offset by revenues from capacity sales of $4,946,711 (line 4), $290,998 of return requirements on Energy Suspension payments (line 4b) which is explained later in my testimony and $56,945,592 of jurisdictional capacity related payments included in base rates (line 8) plus a net overrecovery of $10,479,736 (line 9). The net overrecovery of $10,479,736 reflects actual costs for January 1997 through May 1997 and revised estimates for June 1997 through September 1997. Actual costs for the period October 1996 through December 1996 were included in the CCR midcourse correction filed on January 16, 1997 and approved by the Commission in Order No. PSC-97-0359-FOF-EI issued on March 31, 1997.

Q. Is FPL requesting recovery of any additional costs through the CCR?

A. Yes. FPL is requesting that it be authorized to collect, during the next seventeen (17) years, approximately $4.7 million per year associated with future capacity payments to be made to Jacksonville Electric Authority (JEA). FPL is requesting to collect this annual amount, because there is a mismatch between the period over which FPL currently anticipates it will continue to receive energy from JEA's ownership share of SJRPP, and the period over which FPL is contractually required to make annual capacity payments to JEA. Mr. Rene Silva's testimony describes the circumstances that underlie FPL's request.

Q. Please explain the SJRPP energy suspension issue.

A. An Internal Revenue Service (IRS) ruling, which established the tax exempt status of the municipal bonds used to finance JEA's ownership interests in SJRPP stipulates that FPL shall not receive more than twenty-five (25%) of the nameplate capacity of JEA's ownership share of the plant over the life of the bonds. According to FPL's contract with JEA, FPL agreed to purchase 37.5% of energy produced by JEA's share of the plant, based on a projected plant capacity factor of approximately 67%. This is equivalent to 25% of the plant's total capability. Since commercial operation in 1987, the plant has run at a higher capacity factor than projected and, therefore, FPL's customers have received more energy from SJRPP in the early years than originally anticipated. When FPL reaches the 25% limit, which has been calculated to be 80,534,332 mWh, based on the nameplate rating times the life of the bonds, FPL will be suspended from taking energy until the bonds are paid off. FPL is taking as much SJRPP energy as possible currently, and we project that the energy limit will be reached in 2015. Thereafter FPL will, consistent with the contract, continue making capacity payments through 2020, but would receive no energy from JEA's share of SJRPP ("SJRPP energy suspension").

Q. How was the $4.7 million per year amount to be recovered through the CCR determined?

A. Municipal bonds are used to finance JEA's ownership share of SJRPP. FPL makes capacity payments based on debt service amortization over the life of the bonds. When FPL reaches the 25% limit, which has been calculated to be 80,534,332 mWh, based on the nameplate rating times the life of the bonds, FPL will be suspended from taking energy until the bonds are paid off. Based on the average capacity factor for the last five years, FPL has projected that the 80,534,332 mWh limit will be reached in 2015. Based on FPL's debt service forecast, from 2015 through 2020, FPL is obligated to pay $80 million in capacity payments. An annual accrual of $4.7 million collected through the Capacity Cost Recovery Clause over the 17 year period, from 1998 through 2015, results in the recovery of the $80 million needed to make the capacity payments to JEA during the energy suspension period from 2015 through 2020. FPL proposes to update the debt service forecast as well as the five year average capacity factor each year in FPL's Capacity Cost Recovery filing, therefore, the accrual amount will change each year.

The $4.7 million annual payment for the SJRPP energy suspension payments will be recorded as a liability on FPL books when received from the customers. FPL proposes to pay the customers a return on the liability until all amounts are paid to JEA during the suspension period. The methodology used to calculate the return requirements to the customer is the same that is being used in determining the return on assets in the Fuel Cost Recovery Clause. For the 12 month period ending September

30, 1998, expenses recoverable through the CCR will be reduced by approximately $291,000, to reflect the return requirements on the suspension payments received during the same period (Appendix III, page 3, line 4b).

Q. What is the basis for requesting recovery of costs associated with this issue through the Capacity Cost Recovery Clause now?

A. FPL is requesting that $4.7 million annually associated with the SJRPP energy suspension be recovered through the CCR beginning in 1998 because there is a mismatch between the period over which FPL currently anticipates it will continue to receive energy from JEA's ownership share of SJRPP, and the period over which FPL is contractually required to make annual capacity payments to JEA. FPL is requesting to collect this annual amount from 1998 through 2014 so that in the years 2015 through 2020, when FPL will receive no energy from JEA's ownership share of SJRPP, FPL's customers would not pay capacity charges.

For these reasons, FPL believes that it is appropriate to bring this issue forward for Commission consideration and approval at this time.

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. The Estimated/Actual True-up for the period October 1996 through September 1997 is an overrecovery, including interest, of $10,479,736 (Appendix III, page 6, line 7). Appendix III, pages 6 and 7 show the calculation supporting the CCR Estimated/Actual True-up amount.

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 $10,479,736 has been included in the calculation of the Capacity Cost Recovery factor for the period October 1997 through September 1998.

Q. Please explain the calculation of the Interest Provision.

A. Appendix III, pages 9 and 10, show 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 1997.

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

A. Yes. Appendix III, page 11, 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. As shown in Appendix III, page 11, line 5, the variance related to capacity charges is a $2.0 million decrease. This variance is primarily due to a $2.8 million decrease in Cypress Settlement payments and a $0.6 million decrease in projected revenues from capacity sales. The decrease in Cypress Settlement payments was primarily due to differences in the timing of payments. The decrease in expected revenues from capacity sales is primarily due to the original projections being adjusted to reflect more current market trends.

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

A. As shown on line 10, Capacity Cost Recovery revenues, net of revenue taxes, are now estimated to be $3.5 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 1997 and continue through Customer billings on cycle day 2 of March 1998 and that the new CCR factors become effective with customer billings on cycle day 3 of October 1997 and continue through cycle day 2 of September 1998. 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 1997?**

A. The total residential bill, excluding taxes and franchise fees, for 1,000 kWh will be $74.34. The base bill for 1,000 residential kWh is $47.46, the fuel cost recovery charge from Schedule E1-E, Page S of Appendix II for a residential customer is $16.46, the Conservation charge is $2.62, the Capacity Cost Recovery charge is $6.74, the Environmental Cost Recovery charge is $.31 and the Gross Receipts Tax is $.75. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10, Page 40 of Appendix II.

Q. **Does this conclude your testimony.**

A. Yes, it does.

APPENDIX I

FUEL COST RECOVERY

FORECAST ASSUMPTIONS

RS-3
DOCKET NO. 970001-EI
FPL WITNESS: R. SILVA
EXHIBIT ____________
PAGES 1-7
JUNE 23, 1997

APPENDIX I
FUEL COST RECOVERY
FORECAST ASSUMPTIONS

TABLE OF CONTENTS

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FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL ($/BBL)

OCTOBER, 1997 THROUGH MARCH, 1998

	1997			1998		
BY SULFUR GRADE	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
0.7% SULFUR	$18.87	$18.98	$18.15	$18.54	$18.11	$17.46
1.0% SULFUR	$18.06	$17.73	$17.39	$17.72	$17.38	$16.72
2.0% SULFUR	$17.79	$17.39	$16.96	$17.29	$17.13	$16.54
2.5% SULFUR	$17.49	$17.06	$16.66	$16.91	$16.83	$16.28

3

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT OIL ($/BBL)

OCTOBER, 1997 THROUGH MARCH, 1998

BY SULFUR GRADE	1997			1998		
	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
0.3% SULFUR	$26.45	$25.49	$24.58	$25.77	$26.71	$26.79
0.5% SULFUR	$25.00	$24.03	$23.12	$24.31	$25.24	$25.32

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

OCTOBER, 1997 THROUGH MARCH, 1998

FUEL TYPE	1997			1998		
	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
COAL	$1.52	$1.52	$1.52	$1.53	$1.53	$1.53

FLORIDA POWER & LIGHT COMPANY

PROJECTED TOTAL NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

OCTOBER, 1997 THROUGH MARCH 1998

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	1997			1998		
	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
FIRM TRANSPORTATION	480	630	630	630	630	630
NON-FIRM	255	100	100	100	100	100
DISPATCH WEIGHTED AVERAGE UNIT PRICE BY TYPE OF TRANSPORTATION SERVICE ($/MMBTU)						
FIRM TRANSPORTATION	$1.79	$1.60	$1.54	$1.54	$1.48	$1.40
NON-FIRM	$2.48	$2.51	$2.43	$2.43	$2.34	$2.23

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
OCTOBER, 1997 THROUGH MARCH, 1998

PLANT/UNIT	PROJECTED FORCED OUTAGE FACTOR (%)	PROJECTED MAINTENANCE OUTAGE FACTOR (%)	PLANNED OUTAGE FACTOR (%)	OVERHAUL DATES *
Cape Canaveral 1	2.0	4.4	0.0	NONE
Cape Canaveral 2	1.9	5.0	7.7	11/29/97 - 12/12/97
Cutler 5	2.0	2.0	0.0	NONE
Cutler 6	2.0	2.0	0.0	NONE
Lauderdale 4	1.8	1.8	9.9	(03/14/98 - 03/31/98)
Lauderdale 5	1.9	1.9	5.5	11/08/97 - 11/17/97
Fort Myers 1	1.7	2.8	0.0	NONE
Fort Myers 2	1.8	3.8	23.1	11/08/97 - 12/19/97
Manatee 1	2.0	2.1	0.0	NONE
Manatee 2	5.4	4.0	0.0	NONE
Martin 1	2.0	2.0	0.0	NONE
Martin 2	1.8	4.4	0.0	NONE
Martin 3	2.0	2.0	1.6	02/21/98 - 02/26/98**
Martin 4	2.0	2.0	1.6	02/14/98 - 02/19/98**
Port Everglades 1	1.9	1.9	6.6	11/01/97 - 11/12/97
Port Everglades 2	2.0	2.1	0.0	NONE
Port Everglades 3	2.4	1.8	17.6	(02/28/98 - 03/31/98)
Port Everglades 4	2.1	1.7	30.8	10/18/97 - 12/12/97
Putnam 1	2.0	2.0	0.0	NONE
Putnam 2	1.9	1.9	9.6	10/04/97 - 11/07/97**
Riviera 3	1.7	5.5	17.6	(02/28/98 - 03/31/98)
Riviera 4	2.7	4.8	0.0	NONE
Sanford 3	1.6	2.0	30.8	10/25/97 - 12/19/97
Sanford 4	2.0	5.2	0.0	NONE
Sanford 5	2.0	3.6	0.0	NONE
Turkey Point 1	2.0	3.8	0.0	NONE
Turkey Point 2	2.0	4.9	0.0	NONE
Turkey Point 3	3.1	3.1	0.0	NONE
Turkey Point 4	2.8	2.8	9.9	(10/01/97 - 10/18/97)
St.Lucie 1	4.0	2.5	41.8	10/20/97 - 01/03/98
St.Lucie 2	2.8	2.8	0.0	NONE
SJRPP 1	3.8	2.0	0.0	NONE
SJRPP 2	1.8	1.8	17.6	(02/28/98 - 03/31/98)
Scherer 4	4.3	1.9	6.0	(03/21/98 - 03/31/98)

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

** Note: Partial Planned Outage.

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-2
DOCKET NO 970001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT ______________
PAGES 1-45
JUNE 23, 1997

TABLE OF CONTENTS

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: OCTOBER 1997 - MARCH 1998

		(a) DOLLARS	(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$471,166,040	30,537,574	1.5429
2	Nuclear Fuel Disposal Costs (E2)	9,849,763	10,574,088	0.0932
3	Fuel Related Transactions (E2)	14,333,289	0	0.0000
4	Fuel Cost of Sales to FKEC / CKW (E2)	(10,066,575)	(487,387)	2.0654
5	TOTAL COST OF GENERATED POWER	$485,282,517	30,050,187	1.6149
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	68,696,270	4,300,053	1.5976
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)	32,634,820	1,789,187	1.8240
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)	12,733,760	603,685	2.1093
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 (E2)	1,402,357	0	0.0000
12	Payments to Qualifying Facilities (E8)	66,825,038	3,625,783	1.8431
13	TOTAL COST OF PURCHASED POWER	$182,292,245	10,318,708	1.7666
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)		40,368,895	
15	Fuel Cost of Economy Sales (E6)	(26,213,340)	(1,116,293)	2.3482
16	Gain on Economy Sales (E6A)	(4,052,754)	(1,116,293)	0.3631
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(621,700)	(153,043)	0.4062
18	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($30,887,794)	(1,269,336)	2.4334
19a	Net Inadvertent Interchange	0	0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	$636,686,967	39,099,559	1.6284
21	Net Unbilled Sales	(23,242,090) **	(1,427,319)	(0.0614)
22	Company Use	1,910,061 **	117,299	0.0050
23	T & D Losses	41,384,653 **	2,541,471	0.1093
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$636,686,967	37,868,108	1.6813
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$1,646,663	97,938	1.6813
26	Jurisdictional MWH Sales	$635,040,304	37,770,170	1.6813
27	Jurisdictional Loss Multiplier	-	-	1.00074
28	Jurisdictional MWH Sales Adjusted for Line Losses	$635,510,234	37,770,170	1.6826
29	FINAL TRUE-UP OCT 96 - MAR 97 $13,141,163 overrecovery; EST/ACT TRUE-UP APR 97 - SEP 97 $14,618,648 overrecovery	(27,759,811)	37,770,170	(0.0735)
30	TOTAL JURISDICTIONAL FUEL COST	$607,750,423	37,770,170	1.6091
31	Revenue Tax Factor			1.01609
32	Fuel Factor Adjusted for Taxes			1.6350
33	GPIF ***	$2,900,970	37,770,170	0.0077
34	Fuel Factor including GPIF (Line 31 + Line 32)			1.6427
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			1.643

** 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 1997 THROUGH MARCH 1998

1. Estimated over/(under) recovery (2 months actual, 4 months estimated period) (Schedule E1-B)	$ 14,618,648
2. Final True-Up (6 months actual period)	$ 13,141,163
3.Total over/(under) recovery (Lines 1 + 2) To be included in 6 month projected period (Schedule E1, Line 29)	$ 27,759,811
2. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	37,770,170
3. True-Up Factor (Lines 3/4) c/kWh:	0.0735

	CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT							SCHEDULE E-1b
	COMPANY: FLORIDA POWER & LIGHT COMPANY							PAGE 1 of 1
	FOR THE PERIOD APRIL 1997 THROUGH SEPTEMBER 1997							
	ACTUALS THROUGH MAY 1997 - REVISED ESTIMATES FOR JUNE THROUGH SEPTEMBER 1997							
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	$ 89,103,192	$ 110,361,510	$ 105,545,140	$ 109,575,430	$ 113,685,990	$ 108,356,910	$ 636,628,172
b	Nuclear Fuel Disposal Costs	1,323,636	1,539,386	1,926,339	1,864,200	1,926,339	1,617,260	10,197,161
c	Coal Cars Depreciation & Return	476,904	444,738	440,888	438,803	436,718	434,633	2,672,764
d	Nuclear Thermal Uprate Amortization & Return	417,038	413,486	409,934	406,382	402,830	399,277	2,448,947
e	Gas Pipelines Depreciation & Return	291,042	289,473	287,904	286,335	284,766	283,197	1,722,717
f	DOE D&D Fund Payment	0	0	0	0	0	0	0
2	Fuel Cost of Power Sold	(2,061,716)	(797,354)	(2,323,394)	(2,641,933)	(2,214,782)	(2,031,326)	(12,270,505)
3 a	Fuel Cost of Purchased Power	11,737,342	12,714,173	13,282,640	11,966,790	13,763,730	10,744,890	74,209,565
b	Energy Payments to Qualifying Facilities	10,803,856	11,669,155	10,982,717	12,340,457	11,726,291	11,692,699	69,215,175
4	Energy Cost of Economy Purchases	2,723,869	5,486,158	7,486,250	9,220,130	7,719,510	10,981,130	43,617,047
5	Total Fuel Costs & Net Power Transactions	$ 114,815,243	$ 142,120,726	$ 137,838,419	$ 143,456,594	$ 147,731,392	$ 142,478,670	$ 828,441,042
6	**Adjustments to Fuel Cost:**							
a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(1,722,671)	(1,510,560)	$ (1,858,778)	$ (1,998,171)	$ (2,069,255)	$ (2,117,063)	$ (11,276,498)
b	Reactive and Voltage Control Fuel Revenue	(40,615)	(39,824)	$ 0	$ 0	$ 0	$ 0	(80,439)
c	Inventory Adjustments	48,611	(6,430)	0	0	0	0	42,181
d	Non Recoverable Oil/Tank Bottoms	(83,083)	(116,283)	0	0	0	0	(199,366)
e	Modifications to Burn Low Gravity Oil	19,877	18,734	0	0	0	0	38,611
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 113,037,361	$ 140,466,363	$ 135,979,641	$ 141,458,423	$ 145,662,137	$ 140,361,607	$ 816,965,531
B	**kWh Sales**							
1	Jurisdictional kWh Sales (RTP @ CBL) (a)	5,865,613,712	6,037,717,818	7,007,950,000	7,563,989,000	7,777,068,000	7,793,974,000	42,046,312,530
2	Sale for Resale (excluding FKEC & CKW)	10,733,783	10,407,814	19,673,000	35,247,000	42,311,000	46,932,000	165,304,596
3	Sub-Total Sales (excluding FKEC & CKW)	5,876,347,495	6,048,125,632	7,027,623,000	7,599,236,000	7,819,379,000	7,840,906,000	42,211,617,126
6	**Jurisdictional % of Total kWh Sales (lines B1/B3)**	99.81734 %	99.82792 %	99.72006 %	99.53618 %	99.45890 %	99.40145 %	99.60839 %
C	**True-up Calculation**							
1	Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 126,584,090	$ 130,229,558	$ 151,182,089	$ 163,177,486	$ 167,774,226	$ 168,138,938	$ 907,086,389
2	**Fuel Adjustment Revenues Not Applicable to Period:**							
a	Prior Period True-up Provision	(12,850,832)	(12,850,832)	(12,850,832)	(12,850,832)	(12,850,832)	(12,850,832)	(77,104,991)
b	GPIF, Net of Revenue Taxes (b)	-	-	-	-	-	-	
c	Oil Backout Revenues, Net of revenue Taxes	595	642	0	0	0	0	1,237
3	Jurisdictional Fuel Revenues Applicable to Period	$ 113,733,854	$ 117,379,368	$ 138,331,258	$ 150,326,654	$ 154,923,394	$ 155,288,107	$ 829,982,635
4 a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 113,037,361	$ 140,466,363	$ 135,979,641	$ 141,458,423	$ 145,662,137	$ 140,361,607	$ 816,965,531
b	Nuclear Fuel Expense - 100% Retail	11,859	0	0	0	0	0	11,859
c	RTP Incremental Fuel -100% Retail	82,558	56,069	0	0	0	0	138,627
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)	112,942,943	140,410,293	135,979,641	141,458,423	145,662,138	140,361,607	816,815,045
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.81734 %	99.82792 %	99.72006 %	99.53618 %	99.45890 %	99.40145 %	99.60839 %
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.000701) +(Lines C4b,c,d)	$ 112,911,102	$ 140,324,264	$ 135,695,255	$ 140,902,280	$ 144,976,821	$ 139,620,533	$ 814,430,256
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 822,751	$ (22,944,896)	$ 2,636,003	$ 9,424,374	$ 9,946,573	$ 15,667,574	$ 15,552,379
8	Interest Provision for the Month (Line D10)	(270,399)	(259,966)	(248,134)	(161,180)	(56,762)	62,711	(933,731)
9	True-up & Interest Provision Beg of Period - Over/(Under) Recovery	(77,104,991)	(63,701,807)	(74,055,838)	(58,817,138)	(36,703,112)	(13,962,470)	(77,104,991)
a	Deferred True-up Beginning of Period - Over/(Under) Recovery	13,141,163	13,141,163	13,141,163	13,141,163	13,141,163	13,141,163	13,141,163
10	Prior Period True-up Collected/(Refunded) This Period	12,850,832	12,850,832	12,850,832	12,850,832	12,850,832	12,850,832	77,104,991
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (50,560,644)	$ (60,914,674)	$ (45,675,975)	$ (23,561,949)	$ (821,307)	$ 27,759,811	$ 27,759,811

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 per Order No. PSC-97-0359-FOF-EI is zero.

			FLORIDA POWER & LIGHT COMPANY FUEL COST RECOVERY CLAUSE CALCULATION OF ESTIMATED/ACTUAL VARIANCE FOR THE PERIOD APRIL 1997 THROUGH SEPTEMBER 1997				
				(1)	(2)	(3)	(4)
LINE NO.				ESTIMATED / ACTUAL	ORIGINAL PROJECTIONS (a)	VARIANCE AMOUNT	VARIANCE %
A	1	a	Fuel Cost of System Net Generation (c)	$ 636,628,172	$ 648,481,370	$ (11,853,198)	(1.8) %
		b	Nuclear Fuel Disposal Costs	10,197,161	10,224,339	(27,178)	(0.3) %
		c	Coal Cars Depreciation & Return	2,672,764	2,711,727	(38,963)	(1.4) %
		d	Nuclear Thermal Uprate Amortization & Return	2,448,947	2,914,558	(465,611)	(27.0) %
		e	Gas Pipelines Depreciation & Return	1,722,717	1,722,717	0	N/A
		f	DOE D&D Fund Payment	0	0	0	0.0 %
	2		Fuel Cost of Power Sold	(12,270,505)	(18,611,572)	6,341,067	(34.1) %
	3	a	Fuel Cost of Purchased Power	74,209,565	72,596,350	1,613,215	2.2 %
		b	Energy Payments to Qualifying Facilities	69,215,175	81,519,989	(12,304,814)	(15.1) %
	4		Energy Cost of Economy Purchases	43,617,047	53,242,230	(9,625,183)	(18.1) %
	5		Total Fuel Costs & Net Power Transactions	$ 828,441,042	$ 854,801,708	$ (26,360,666)	(3.1) %
	6		Adjustments to Fuel Cost:				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (11,276,498)	$ (11,387,249)	$ 110,751	(1.0) %
		b	Reactive and Voltage Control Fuel Revenue	$ (80,439)	0	(80,439)	N/A
		c	Inventory Adjustments	42,181	0	42,181	N/A
		d	Non Recoverable Oil/Tank Bottoms	(199,366)	0	(199,366)	N/A
		e	Modifications to Burn Low Gravity Oil	38,611	2,087,140	(2,048,529)	(98.2) %
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 816,965,531	$ 845,501,599	$ (28,536,068)	(3.4) %
C	1		Jurisdictional kWh Sales	42,046,312,530	42,644,754,000	(598,441,470)	(1.4) %
	2		Sale for Resale	165,304,596	165,869,000	(564,404)	(0.3) %
	3		Total Sales (Excluding RTP Incremental)	42,211,617,126	42,810,623,000	(599,005,874)	(1.4) %
	4		Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
D	1		Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$ 907,036,389	$ 922,606,590	$ (15,520,201)	(1.7) %
		a	Prior Period True-up Provision	(77,104,991)	(77,104,991)	0	0.0 %
		b	Generation Performance Incentive Factor Net (b)	0	0	0	N/A
		c	Oil Backout Revenues, Net of revenue Taxes	1,237	0	1,237	N/A
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 829,982,635	$ 845,501,599	$ (15,518,964)	(1.8) %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 816,965,531	$ 845,501,599	$ (28,536,068)	(3.4) %
		b	Nuclear Fuel Expense - 100% Retail	11,859	0	11,859	N/A
		c	RTP Incremental Fuel -100% Retail	138,627	0	138,627	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)	816,815,045	845,501,599	(28,686,554)	(3.4) %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 814,430,256	$ 845,501,599	$ (31,071,343)	(3.7) %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ 15,552,379	$ 0	$ 15,552,379	N/A
	8		Interest Provision for the Month	(933,731)	0	(933,731)	N/A
	9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(77,104,991)	(77,104,991)	0	0.0 %
		a	Deferred True-up Beginning of Period - Over/(Under) Recovery	13,141,163	0	13,141,163	N/A
	10		Prior Period True-up Collected/(Refunded) This Period	77,104,991	77,104,991	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ 27,759,811	$ 0	$ 27,759,811	N/A
			(a) Per Schedule E-2, filed January 16, 1997.				
			(b) Generation Performance Incentive Factor per Order No. PSC-96-1172-FOF-EI. (($1,947,105* 98.4167)/6)				
			(c) Includes payments for Mission Settlement.				

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: OCTOBER 1997 THROUGH MARCH 1998

1. TOTAL AMOUNT OF ADJUSTMENTS:	(24,858,841)
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$2,900,970
B. TRUE-UP (OVER)/UNDER RECOVERED	$ (27,759,811)
2. TOTAL JURISDICTIONAL SALES (MWH)	37,770,170
3. ADJUSTMENT FACTORS c/kWh:	(0.0658)
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0077
B. TRUE-UP FACTOR	(0.0735)

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

OCTOBER 1997 - MARCH 1998

NET ENERGY FOR LOAD (%)

		FUEL COST (%)
ON PEAK	28.22	29.72
OFF PEAK	71.78	70.28
	100.00	100.00

FUEL RECOVERY CALCULATION

	TOTAL	ON-PEAK	OFF-PEAK
1 TOTAL FUEL & NET POWER TRANS	$636,686,967	$189,223,367	$447,463,600
2 MWH SALES	37,868,108	10,686,380	27,181,728
3 COST PER KWH SOLD	1.6813	1.7707	1.6462
4 JURISDICTIONAL LOSS FACTOR	1.00074	1.00074	1.00074
5 JURISDICTIONAL FUEL FACTOR	1.6826	1.7720	1.6474
6 TRUE-UP	(0.0735)	(0.0735)	(0.0735)
7			
8 TOTAL	1.6091	1.6985	1.5739
9 REVENUE TAX FACTOR	1.01609	1.01609	1.01609
10 RECOVERY FACTOR	1.6350	1.7258	1.5992
11 GPIF	0.0077	0.0077	0.0077
12 RECOVERY FACTOR including GPIF	1.6427	1.7335	1.6069
13 RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	1.643	1.734	1.607

HOURS:	ON-PEAK	23.16 %
	OFF-PEAK	76.84 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

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

OCTOBER 1997 - MARCH 1998

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		1.643	1.00213	1.646
A-1*	SL-1, OL-1		1.627	1.00213	1.630
B	GSD-1		1.643	1.00212	1.646
C	GSLD-1 & CS-1		1.643	1.00179	1.646
D	GSLD-2, CS-2, OS-2 & MET		1.643	0.99591	1.636
E	GSLD-3 & CS-3		1.643	0.95658	1.571
A	RST-1, GST-1	ON-PEAK	1.734	1.00213	1.737
		OFF-PEAK	1.607	1.00213	1.610
B	GSDT-1	ON-PEAK	1.734	1.00212	1.737
	CILC-1(G)	OFF-PEAK	1.607	1.00212	1.610
C	GSLDT-1 &	ON-PEAK	1.734	1.00179	1.737
	CST-1	OFF-PEAK	1.607	1.00179	1.610
D	GSLDT-2 &	ON-PEAK	1.734	0.99591	1.726
	CST-2	OFF-PEAK	1.607	0.99591	1.600
E	GSLDT-3,CST-3,	ON-PEAK	1.734	0.95658	1.658
	CILC -1(T) & ISST-1(T)	OFF-PEAK	1.607	0.95658	1.537
F	CILC -1(D) &	ON-PEAK	1.734	0.99785	1.730
	ISST-1(D)	OFF-PEAK	1.607	0.99785	1.603

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

Florida Power & Light Company
1998 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	41,304,530	1.072937537	44,317,160	0.932021	3,012,651	1.00213
2							
3	GS-1 Sec	4,790,032	1.072937537	5,139,225	0.932021	349,393	1.00213
4							
5	GSD-1 Pri	4,787	1.048417800	5,009	0.955841	222	
6	GSD-1 Sec	17,495,317	1.072937537	18,771,275	0.932021	1,276,058	
7	Subtot GSD-1	17,500,095	1.072930303	18,776,285	0.932027	1,276,280	1.00212
8							
9	OS-2 Pri	20,857	1.048417800	21,835	0.955841	[illegible]	0.87736
10							
11	GSLD-1 Pri	86,695	1.048417800	90,717	0.955841	4,024	
12	GSLD-1 Sec	6,845,175	1.072937537	7,344,445	0.932021	499,270	
13	Subtot GSLD-1	6,931,869	1.072605879	7,435,162	0.932309	503,294	1.00182
14							
15	CS-1 Pri	10,203	1.048417800	10,677	0.955841	474	
16	CS-1 Sec	189,301	1.072937537	203,108	0.932021	13,807	
17	Subtot CS-1	199,504	1.071691204	213,785	0.933190	14,281	1.00089
18							
19	Subtot GSLD1 / CS1	7,131,372	1.072577208	7,648,947	0.932334	517,575	1.00179
20							
21	GSLD-2 Pri	237,855	1.048417800	248,890	0.955841	11,031	
22	GSLD-2 Sec	929,372	1.072937537	997,168	0.932021	67,786	
23	Subtot GSLD-2	1,167,228	1.067937839	1,245,844	0.936795	78,817	0.99706
24							
25	CS-2 Pri	6,395	1.048417800	6,682	0.955841	287	
26	CS-2 Sec	108,302	1.072937537	116,158	0.932021	7,896	
27	Subtot CST-2	114,657	1.071468049	122,850	0.933307	8,193	1.00075
28							
29	Subtot GSLD2 / CS2	1,281,883	1.067867672	1,368,693	0.936429	87,011	0.99741
30							
31	GSLD-3 Trn	599,232	1.024172189	613,717	0.976389	14,485	0.95658
32							
33	CS-3 Trn	0	1.024172189	0	0.000000	0	0.00000
34							
35	Subtot GSLD3 / CS3	599,232	1.024172189	613,717	0.976389	14,485	0.95658
36							
37	ISST-1 Sec	655	1.072937537	703	0.932021	48	1.00213
38							
39	SST-1 Pri	36,722	1.048417800	38,427	0.955841	1,705	
40	SST-1 Sec	17,837	1.072937537	19,138	0.932021	1,301	
41	SST-1 (D)	54,559	1.056087938	57,564	0.947785	3,006	0.98646
42							
43	SST-1 Trn	89,758	1.024172189	91,928	0.976389	2,170	0.95638
44							
45	CILC D Pri	436,108	1.048417800	456,303	0.955841	20,197	
46	CILC D Sec	2,086,162	1.072937537	2,238,321	0.932021	152,159	
47	CILC D	2,521,307	1.068360913	2,693,624	0.936013	172,356	0.99765
48							
49	CILC G Sec	217,866	1.072937537	233,764	0.932021	15,898	1.00213
50							
51	Subtot CILC D / CILC G	2,739,233	1.068735004	2,927,487	0.935694	188,254	0.99819
52							
53	CILC T Trn	1,148,304	1.024172189	1,176,061	0.976389	27,757	0.9565*
54							
55	ISST-D & CILC-D	2,621,622	1.066362102	2,694,326	0.936017	172,404	0.99765
56							
57	GSD-1 & CILC-1(G)	17,717,970	1.072930372	19,010,149	0.932027	1,292,179	1.00212
58							
59	MET Pri	83,212	1.048417800	87,075	0.955841	3,863	0.87736
60							
61	OS-2, GSLD2, CS2, & MET	1,385,753	1.066275427	1,477,594	0.937844	91,841	0.99591
62							
63	OL-1 Sec	100,979	1.072937537	108,343	0.932021	7,365	1.00213
64							
65	SL-1 Sec	334,193	1.072937537	358,569	0.932021	24,375	1.00213
66							
67	Subtot OL1 / SL1	435,171	1.072937537	466,912	0.932021	31,740	1.00213
68							
69	SL-2 Sec	72,472	1.072937537	77,758	0.932021	5,286	1.00213
70							
71	RTP-1 Pri	0	1.048417800	0	0.000000	0	
72	RTP-1 Sec	60,029	1.072937537	64,407	0.932021	4,378	
73	Subtot RTP-1	60,029	1.072937537	64,407	0.932021	4,378	1.00213
74							
75	RTP-2 Pri	1,406	1.048417800	1,471	0.955841	65	
76	RTP-2 Sec	110,067	1.072937537	118,095	0.932021	8,028	
77	Subtot RTP-2	111,473	1.072623139	119,566	0.932311	8,093	1.00182
78							
79	RTP-3 Trn	25,352	1.024172189	25,965	0.976389	613	0.95658
80							
81	Total FPSC	77,446,837	1.071448529	82,980,307	0.933314	5,533,470	1.00074
82							
83	Total FERC Sales	1,331,141	1.024453351	1,363,692	0.976130	32,551	
84							
85	Total Company	78,777,978	1.070664532	84,344,000	0.934008	5,566,021	
86							
87	Company Use	172,035	1.072937537	184,583	0.932021	12,548	
88							
89	Total FPL	78,950,013	1.070658607	84,528,582	0.934004	5,578,569	1.00000
90							
91	Summary of Sales by Voltage						
92							
93	Transmission	3,176,963	1.024172189	3,253,757	0.976388	76,794	
94							
95	Primary	939,861	1.048417800	983,487	0.955841	43,626	
96							
97	Secondary	74,661,155	1.072937537	80,106,756	0.932021	5,445,601	
98							
99	Total	78,777,979	1.070664532	84,344,000	0.934008	5,566,021	

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD OCTOBER 1997 - MARCH 1998

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	$91,943,470	$77,867,010	$81,053,470	$77,333,000	$67,084,500	$75,884,590	$471,166,040	A1
1a	NUCLEAR FUEL DISPOSAL	1,426,712	1,413,102	1,367,518	1,884,123	1,783,604	1,974,704	9,849,763	1a
1b	COAL CAR INVESTMENT	436,080	433,995	431,910	429,825	427,741	425,656	2,585,207	1b
1c	NUCLEAR THERMAL UPRATE	395,725	392,173	388,621	435,798	482,975	479,423	2,574,715	1c
1d	GAS LATERAL ENHANCEMENTS	281,627	280,058	278,489	276,920	275,351	273,782	1,666,227	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	5,420,000	0	0	0	0	5,420,000	1e
1f	LOW GRAVITY FUEL MODIFICATIONS	0	0	0	0	0	2,087,140	2,087,140	1f
2	FUEL COST OF POWER SOLD	(2,567,057)	(6,638,173)	(4,681,015)	(4,891,482)	(5,939,433)	(6,170,634)	(30,887,794)	2
3	FUEL COST OF PURCHASED POWER	10,614,490	10,673,480	11,263,900	13,099,910	12,021,410	11,023,100	68,696,270	3
3a	MISSION SETTLEMENT	1,108,357	147,000	0	0	147,000	0	1,402,357	3a
3b	QUALIFYING FACILITIES	12,176,373	9,167,575	12,393,309	12,299,565	9,863,984	10,924,232	66,825,038	3b
4	ENERGY COST OF ECONOMY PURCHASES	10,647,850	12,273,390	8,568,570	4,793,230	4,515,470	4,570,070	45,368,580	4
4a	FUEL COST OF SALES TO FKEC / CKW	(1,918,224)	(1,857,342)	(1,653,037)	(1,551,181)	(1,562,984)	(1,523,807)	(10,066,575)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$124,545,403	$109,572,248	$109,411,735	$104,109,708	$89,099,618	$99,948,256	$636,686,967	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	7,505,797	6,269,952	5,969,875	6,158,598	6,021,896	5,941,990	37,868,108	6
7	COST PER KWH SOLD (¢/KWH)	1.6593	1.7476	1.8327	1.6905	1.4796	1.6821	1.6813	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00074	1.00074	1.00074	1.00074	1.00074	1.00074	1.00074	7a
7b	JURISDICTIONAL COST (¢/KWH)	1.6606	1.7489	1.8341	1.6917	1.4807	1.6833	1.6826	7b
9	TRUE-UP (¢/KWH)	(0.0619)	(0.0739)	(0.0776)	(0.0752)	(0.0770)	(0.0781)	(0.0735)	9
10	TOTAL	1.5987	1.6750	1.7565	1.6165	1.4037	1.6052	1.6091	10
11	REVENUE TAX FACTOR 0.01609	0.0257	0.0270	0.0283	0.0260	0.0226	0.0258	0.0259	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	1.6244	1.7020	1.7848	1.6425	1.4263	1.6310	1.6350	12
13	GPIF (¢/KWH)	0.0065	0.0077	0.0081	0.0079	0.0080	0.0082	0.0077	13
14	RECOVERY FACTOR including GPIF	1.6309	1.7097	1.7929	1.6504	1.4343	1.6392	1.6427	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	1.631	1.710	1.793	1.650	1.434	1.639	1.643	15

Florida Power & Light Company
5/27/97

Generating System Comparative Data by Fuel Type

	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Total
Fuel Cost of System Net Generation ($)							
1 Heavy Oil	$30,318,910	$23,910,090	$29,261,890	$19,875,420	$18,430,000	$24,158,350	$145,974,660
2 Light Oil	$0	$0	$0	$101,610	$0	$0	$101,610
3 Coal	$9,988,790	$10,011,120	$9,686,770	$10,251,260	$9,367,190	$7,185,020	$56,490,150
4 Gas	$45,960,520	$38,620,180	$36,927,000	$39,817,090	$32,347,340	$36,850,390	$230,522,520
5 Nuclear	$5,675,250	$5,325,620	$5,157,810	$7,287,620	$6,939,970	$7,690,830	$38,077,100
6 Orimulsion	$0	$0	$0	$0	$0	$0	$0
7 *Total*	$91,943,470	$77,867,010	$81,053,470	$77,333,000	$67,084,500	$75,884,590	$471,166,040
System Net Generation (MWH)							
8 Heavy Oil	1,300,717	1,028,291	1,210,423	822,236	781,917	1,055,714	6,199,298
9 Light Oil	0	0	0	1,268	0	0	1,268
10 Coal	587,857	593,914	577,245	609,137	555,481	420,906	3,344,540
11 Gas	2,189,865	1,783,250	1,431,058	1,704,319	1,579,298	1,730,590	10,418,380
12 Nuclear	1,531,629	1,517,018	1,468,082	2,022,676	1,914,765	2,119,918	10,574,088
13 Orimulsion	0	0	0	0	0	0	0
14 *Total*	5,610,068	4,922,473	4,686,808	5,159,636	4,831,461	5,327,128	30,537,574
Units of Fuel Burned							
15 Heavy Oil (BBLS)	1,988,060	1,561,881	1,857,804	1,278,326	1,199,684	1,596,040	9,481,795
16 Light Oil (BBLS)	0	0	0	3,354	0	0	3,354
17 Coal (TONS)	303,208	302,964	292,388	310,367	283,335	219,735	1,711,997
18 Gas (MCF)	18,825,494	14,529,423	10,876,396	13,813,371	12,756,386	14,130,563	84,931,633
19 Nuclear (MBTU)	16,850,332	16,375,812	15,847,560	21,836,600	20,671,904	22,886,752	114,468,960
20 Orimulsion (BBLS)	0	0	0	0	0	0	0
BTU Burned (MMBTU)							
21 Heavy Oil	12,723,581	9,996,040	11,889,941	8,181,286	7,677,978	10,214,654	60,683,479
22 Light Oil	0	0	0	19,555	0	0	19,555
23 Coal	5,935,831	5,940,988	5,779,141	6,095,074	5,559,382	4,240,551	33,550,966
24 Gas	18,825,494	14,529,423	10,876,396	13,813,371	12,756,386	14,130,563	84,931,633
25 Nuclear	16,850,332	16,375,812	15,847,560	21,836,600	20,671,904	22,886,752	114,468,960
26 Orimulsion	0	0	0	0	0	0	0
27 *Total*	54,335,238	46,842,263	44,393,038	49,945,885	46,665,650	51,472,520	293,654,593

Florida Power & Light Company
5/27/97

Generating System Comparative Data by Fuel Type

	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Total
Generation Mix (%MWH)							
28 Heavy Oil	23.19%	20.69%	25.83%	15.94%	16.18%	19.82%	20.30%
29 Light Oil	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%
30 Coal	10.48%	12.07%	12.32%	11.81%	11.50%	7.90%	10.95%
31 Gas	39.03%	36.23%	30.53%	33.03%	32.69%	32.49%	34.12%
32 Nuclear	27.30%	30.82%	31.32%	39.20%	39.63%	39.79%	34.63%
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 ($/BBL)	15.2505	15.3085	15.7616	15.5480	15.3624	15.1364	15.3953
36 Light Oil ($/BBL)	0.0000	0.0000	0.0000	30.2952	0.0000	0.0000	30.2952
37 Coal ($/ton)	32.9437	33.0439	33.1298	33.0295	33.0605	32.6986	32.9966
38 Gas ($/MCF)	2.4414	2.6581	3.3952	2.8825	2.5358	2.6079	2.7142
39 Nuclear ($/MBTU)	0.3368	0.3252	0.3255	0.3337	0.3357	0.3360	0.3326
40 Orimulsion ($/BBL)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Fuel Cost per MMBTU ($/MMBTU)							
41 Heavy Oil	2.3829	2.3920	2.4627	2.4294	2.4004	2.3651	2.4055
42 Light Oil	0.0000	0.0000	0.0000	5.1961	0.0000	0.0000	5.1961
43 Coal	1.6828	1.6851	1.6762	1.6819	1.6849	1.6944	1.6837
44 Gas	2.4414	2.6581	3.3952	2.8825	2.5358	2.6079	2.7142
45 Nuclear	0.3368	0.3252	0.3255	0.3337	0.3357	0.3360	0.3326
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	9,782	9,721	9,823	9,950	9,819	9,676	9,789
47 Light Oil	0	0	0	15,422	0	0	15,422
48 Coal	10,097	10,003	10,012	10,006	10,008	10,075	10,032
49 Gas	8,597	8,148	7,600	8,105	8,077	8,165	8,152
50 Nuclear	11,002	10,795	10,795	10,796	10,796	10,796	10,825
51 Orimulsion	0	0	0	0	0	0	0
Generated Fuel Cost per KWH (cents/KWH)							
52 Heavy Oil	2.3309	2.3252	2.4191	2.4172	2.3570	2.2883	2.3547
53 Light Oil	0.0000	0.0000	0.0000	8.0134	0.0000	0.0000	8.0134
54 Coal	1.6992	1.6856	1.6781	1.6829	1.6863	1.7070	1.6890
55 Gas	2.0988	2.1657	2.5804	2.3362	2.0482	2.1294	2.2127
56 Nuclear	0.3705	0.3511	0.3513	0.3603	0.3624	0.3628	0.3601
57 Orimulsion	0	0	0	0	0	0	0
58 *Total*	1.6389	1.5819	1.7294	1.4988	1.3885	1.4245	1.5429

Date: 5/13/97
Company: Florida Power & Light

Schedule E4
Page: 1

Estimated For The Period of : Oct-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	404	29,415	49.9	94.2	74.8	10,170	Heavy Oil BBLS ->	44,710	6,400,002	286,143	753,609	2.5620
2			114,688					Gas MCF ->	1,179,388	1,000,000	1,179,388	2,628,477	2.2919
3													
4	TRKY O 2	403	11,938	45.7	93.1	76.4	10,204	Heavy Oil BBLS ->	18,136	6,399,987	116,068	305,685	2.5606
5			119,720					Gas MCF ->	1,227,330	1,000,000	1,227,330	2,456,830	2.0521
6													
7	TRKY N 3	717	466,105	93.2	90.5	96.9	11,114	Nuclear MBTU ->	5,180,202	1,000,000	5,180,202	1,550,435	0.3326
8													
9	TRKY N 4	717	174,899	34.8	83.2	97.3	11,073	Nuclear MBTU ->	1,936,663	1,000,000	1,936,663	646,071	0.3694
10													
11	FT LAUD4	452	304,493	98.0	88.7	95.5	7,895	Gas MCF ->	2,403,905	1,000,000	2,403,905	4,266,931	1.4013
12													
13	FT LAUD5	452	304,493	98.0	93.5	95.5	7,895	Gas MCF ->	2,403,905	1,000,000	2,403,905	4,266,931	1.4013
14													
15	PT EVER1	212	1,751	11.6	92.9	80.2	11,135	Heavy Oil BBLS ->	2,891	6,400,104	18,503	45,393	2.5930
16			15,929					Gas MCF ->	178,363	1,000,000	178,363	422,816	2.6544
17													
18	PT EVER2	213	1,340	8.8	95.9	72.6	11,318	Heavy Oil BBLS ->	2,242	6,400,080	14,348	35,199	2.6278
19			12,159					Gas MCF ->	138,423	1,000,000	138,423	327,868	2.6965
20													
21	PT EVER3	396	32,092	72.8	87.3	78.8	10,215	Heavy Oil BBLS ->	48,972	6,399,996	313,423	768,923	2.3960
22			173,044					Gas MCF ->	1,781,982	1,000,000	1,781,982	4,228,969	2.4439
23													
24	PT EVER4	387	10,293	37.1	80.9	80.8	10,326	Heavy Oil BBLS ->	15,843	6,400,009	101,398	248,761	2.4167
25			92,640					Gas MCF ->	961,478	1,000,000	961,478	2,268,642	2.4489
26													
27	RIV 3	292	170,761	83.5	78.6	88.4	9,924	Heavy Oil BBLS ->	264,302	6,400,000	1,691,533	3,831,338	2.2437
28			3,620					Gas MCF ->	38,995	1,000,000	38,995	69,216	1.9119
29													
30	RIV 4	292	112,108	54.9	92.5	83.4	10,033	Heavy Oil BBLS ->	175,246	6,399,999	1,121,576	2,540,380	2.2660
31			2,597					Gas MCF ->	29,292	1,000,000	29,292	51,994	2.0022
32													

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-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)
33	ST LUC 1	853	401,713	66.5	72.7	98.4	10,934	Nuclear MBTU ->	4,392,252	1,000,000	4,392,252	1,656,319	0.4123
34													
35	ST LUC 2	726	488,912	95.0	82.6	98.5	10,925	Nuclear MBTU ->	5,341,217	1,000,000	5,341,217	1,822,422	0.3728
36													
37	CAP CN 1	400	184,233	66.1	92.5	76.9	9,603	Heavy Oil BBLS ->	275,343	6,400,000	1,762,196	4,238,552	2.3006
38			4,802					Gas MCF ->	53,028	1,000,000	53,028	94,124	1.9601
39													
40	CAP CN 2	400	170,301	65.9	89.3	82.2	9,602	Heavy Oil BBLS ->	253,617	6,399,999	1,623,145	3,904,096	2.2925
41			18,214					Gas MCF ->	186,932	1,000,000	186,932	331,804	1.8217
42													
43	SANFRD 3	147	738	7.2	74.2	73.6	10,715	Heavy Oil BBLS ->	1,156	6,400,138	7,399	18,249	2.4721
44			6,644					Gas MCF ->	71,698	1,000,000	71,698	127,264	1.9155
45													
46	SANFRD 4	394	13,707	33.6	90.9	87.6	10,153	Heavy Oil BBLS ->	20,743	6,400,006	132,753	327,413	2.3886
47			80,761					Gas MCF ->	826,385	1,000,000	826,385	1,466,833	1.8163
48													
49	SANFRD 5	394	57,737	37.2	92.5	81.5	9,986	Heavy Oil BBLS ->	87,690	6,400,001	561,217	1,384,144	2.3973
50			46,911					Gas MCF ->	483,753	1,000,000	483,753	858,663	1.8304
51													
52	PUTNAM 1	272	114,998	66.4	94.4	87.0	9,087	Gas MCF ->	1,044,932	1,000,000	1,044,932	1,854,755	1.6129
53													
54	PUTNAM 2	272	128,939	74.4	91.4	87.3	9,084	Gas MCF ->	1,171,349	1,000,000	1,171,349	2,079,144	1.6125
55													
56	MANATE 1	805	101,036	17.6	95.9	65.5	10,107	Heavy Oil BBLS ->	159,549	6,399,998	1,021,116	2,506,056	2.4804
57													
58	MANATE 2	805	148,539	25.8	90.6	74.2	10,133	Heavy Oil BBLS ->	235,170	6,400,001	1,505,066	3,693,830	2.4868
59													
60	FT MY 1	142	46,563	45.8	81.3	77.0	10,293	Heavy Oil BBLS ->	74,889	6,400,004	479,290	1,113,381	2.3911
61													
62	FT MY 2	415	203,544	68.6	82.9	89.7	9,434	Heavy Oil BBLS ->	300,025	6,400,000	1,920,162	4,460,497	2.1914
63													

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Page: 3

Estimated For The Period of : Oct-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	37	0.1	96.0	80.8	12,453	Gas	MCF ->	459	1,000,000	459	814	2.2120
66	CUTLER 6	145	107	0.1	96.0	72.6	11,646	Gas	MCF ->	1,251	1,000,000	1,251	2,220	2.0670
68	MARTIN 1	821	1,174	1.3	96.0	42.7	11,072	Heavy Oil	BBLS ->	1,919	6,399,917	12,281	36,516	3.1109
69			6,635					Gas	MCF ->	74,178	1,000,000	74,178	131,667	1.9844
71	MARTIN 2	821	3,448	4.7	83.1	47.7	11,036	Heavy Oil	BBLS ->	5,616	6,400,061	35,945	106,880	3.1001
72			23,918					Gas	MCF ->	266,065	1,000,000	266,065	472,266	1.9745
74	MARTIN 3	460	307,025	98.7	94.2	93.9	7,000	Gas	MCF ->	2,149,122	1,000,000	2,149,122	3,814,694	1.2425
76	MARTIN 4	460	307,385	98.8	93.7	93.9	7,000	Gas	MCF ->	2,151,650	1,000,000	2,151,650	3,819,176	1.2425
78	FM GT	636	0	0.0	95.0		0	Light Oil	BBLS ->	0	5,333,333	2	8	8.0000
80	FL GT	792	107	0.0	92.0	77.6	15,195	Gas	MCF ->	1,628	1,000,000	1,628	2,890	2.6984
82	PE GT	396	2	0.0	92.0	79.4	17,143	Gas	MCF ->	32	1,000,000	32	56	3.1111
84	SJRPP 1O	116	83,566	0.0	94.2	100.0	9,477	Coal	TONS ->	32,302	24,517,007	791,936	1,270,944	1.5209
86	SJRPP 2O	116	83,746	0.0	87.9	100.0	9,402	Coal	TONS ->	32,117	24,517,000	787,417	1,263,692	1.5090
88	SCHER #4	605	420,545	96.5	90.8	96.5	10,359	Coal	TONS ->	238,790	18,243,998	4,356,477	7,454,154	1.7725
90	TOTAL	16,402	5,610,069				9,685					54,335,267	82,027,991	1.4622

Date: 5/13/97
Company: Florida Power & Light

Schedule E4
Page: 4

Estimated For The Period of : Nov-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	404	22,720	27.5	94.2	73.6	10,027	Heavy Oil	BBLS ->	33,969	6,399,998	217,404	570,623	2.5115
2			59,877					Gas	MCF ->	610,838	1,000,000	610,838	1,245,067	2.0794
3														
4	TRKY O 2	403	7,577	11.5	93.1	70.0	10,059	Heavy Oil	BBLS ->	11,306	6,400,021	72,361	189,924	2.5065
5			26,754					Gas	MCF ->	272,962	1,000,000	272,962	524,744	1.9614
6														
7	TRKY N 3	717	497,174	93.2	90.5	100.0	10,792	Nuclear	MBTU ->	5,365,685	1,000,000	5,365,685	1,606,850	0.3232
8														
9	TRKY N 4	717	506,776	95.0	83.2	100.0	10,792	Nuclear	MBTU ->	5,469,315	1,000,000	5,469,315	1,827,315	0.3606
10														
11	FT LAUD4	452	329,616	98.0	88.7	100.0	7,831	Gas	MCF ->	2,581,229	1,000,000	2,581,229	5,231,151	1.5870
12														
13	FT LAUD5	452	210,982	62.7	93.5	100.0	7,834	Gas	MCF ->	1,652,922	1,000,000	1,652,922	3,304,914	1.5664
14														
15	PT EVER1	212	3,271	2.9	92.9	55.0	11,210	Heavy Oil	BBLS ->	5,536	6,400,047	35,431	87,560	2.6769
16			1,321					Gas	MCF ->	16,041	1,000,000	16,041	33,286	2.5205
17														
18	PT EVER2	213	4,717	3.5	95.9	56.2	11,151	Heavy Oil	BBLS ->	8,013	6,400,020	51,281	126,728	2.6869
19			791					Gas	MCF ->	10,137	1,000,000	10,137	21,034	2.6578
20														
21	PT EVER3	396	127,011	52.3	87.3	73.6	9,926	Heavy Oil	BBLS ->	194,013	6,400,001	1,241,684	3,068,523	2.4160
22			27,224					Gas	MCF ->	289,323	1,000,000	289,323	681,574	2.5036
23														
24	PT EVER4	387		0.0	80.9		0							
25														
26	RIV 3	292	152,021	75.6	78.6	80.9	9,883	Heavy Oil	BBLS ->	233,496	6,399,999	1,494,376	3,433,478	2.2585
27			12,204					Gas	MCF ->	128,736	1,000,000	128,736	265,219	2.1733
28														
29	RIV 4	292	103,721	68.6	92.5	76.8	10,100	Heavy Oil	BBLS ->	160,715	6,400,000	1,028,578	2,365,389	2.2805
30			45,244					Gas	MCF ->	475,933	1,000,000	475,933	954,860	2.1105
31														

Date: 5/13/97
Company: Florida Power & Light

Schedule E4
Page: 5

Estimated For The Period of : Nov-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		0.0	72.7		0						
33													
34	ST LUC 2	726	513,068	95.0	82.6	100.0	10,799	Nuclear MBTU ->	5,540,812	1,000,000	5,540,812	1,891,454	0.3687
35													
36	CAP CN 1	400	74,118	42.2	92.5	70.4	9,760	Heavy Oil BBLS ->	109,634	6,399,999	701,659	1,700,498	2.2943
37			51,403					Gas MCF ->	523,406	1,000,000	523,406	1,055,817	2.0540
38													
39	CAP CN 2	400	62,181	58.0	89.3	74.7	9,797	Heavy Oil BBLS ->	91,681	6,400,002	586,757	1,422,825	2.2882
40			110,425					Gas MCF ->	1,104,335	1,000,000	1,104,335	2,226,496	2.0163
41													
42	SANFRD 3	147		0.0	74.2		0						
43													
44	SANFRD 4	394	34,166	11.7	90.9	75.6	10,193	Gas MCF ->	348,262	1,000,000	348,262	716,136	2.0961
45													
46	SANFRD 5	394	17,474	20.7	92.5	75.6	10,052	Heavy Oil BBLS ->	26,215	6,400,000	167,776	414,268	2.3708
47			43,070					Gas MCF ->	440,829	1,000,000	440,829	906,349	2.1044
48													
49	PUTNAM 1	272	65,504	32.4	94.4	89.4	9,090	Gas MCF ->	595,420	1,000,000	595,420	1,220,434	1.8631
50													
51	PUTNAM 2	272	79,449	39.3	91.4	89.7	9,082	Gas MCF ->	721,531	1,000,000	721,531	1,474,316	1.8557
52													
53	MANATE 1	805	82,743	13.8	95.9	56.4	10,113	Heavy Oil BBLS ->	130,746	6,400,000	836,777	2,064,066	2.4946
54													
55	MANATE 2	805	61,938	10.3	90.6	59.6	10,171	Heavy Oil BBLS ->	98,437	6,399,999	629,994	1,553,976	2.5089
56													
57	FT MY 1	142	43,915	41.6	81.3	67.3	10,250	Heavy Oil BBLS ->	70,335	6,400,002	450,147	1,061,197	2.4165
58													
59	FT MY 2	415	264,586	85.7	82.9	86.5	9,369	Heavy Oil BBLS ->	387,316	6,400,000	2,478,824	5,842,146	2.2080
60													
61	CUTLER 5	72	2	0.0	96.0	76.0	12,210	Gas MCF ->	18	1,000,000	18	37	2.4667
62													

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Page: 6

Estimated For The Period of : Nov-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 6	145	5	0.0	96.0	65.0	11,415	Gas	MCF ->	59	1,000,000	59	123	2.3654
64														
65	MARTIN 1	821	234	0.0	96.0	30.0	10,237	Gas	MCF ->	2,391	1,000,000	2,391	4,961	2.1246
66														
67	MARTIN 2	821	297	1.5	83.1	41.0	10,746	Heavy Oil	BBLS ->	467	6,399,401	2,990	8,890	2.9973
68			8,948					Gas	MCF ->	96,351	1,000,000	96,351	199,928	2.2344
69														
70	MARTIN 3	460	337,822	98.7	94.2	100.0	6,891	Gas	MCF ->	2,328,021	1,000,000	2,328,021	4,717,998	1.3966
71														
72	MARTIN 4	460	338,219	98.8	93.7	100.0	6,891	Gas	MCF ->	2,330,759	1,000,000	2,330,759	4,723,544	1.3966
73														
74	FM GT	636		0.0	95.0		0							
75														
76	FL GT	792	3	0.0	92.0	77.0	15,195	Gas	MCF ->	42	1,000,000	42	87	3.2222
77														
78	PE GT	396	0	0.0	92.0		0	Gas	MCF ->	0	1,000,000	0	0	
79														
80	SJRPP 1O	116	86,352	0.0	94.2	100.0	9,389	Coal	TONS ->	33,070	24,517,020	810,766	1,308,511	1.5130
81														
82	SJRPP 2O	116	86,537	0.0	87.9	100.0	9,316	Coal	TONS ->	32,882	24,516,986	806,170	1,299,105	1.5012
83														
84	SCHER #4	605	421,025	93.5	90.8	93.5	10,270	Coal	TONS ->	237,012	18,243,998	4,324,052	7,405,506	1.7589
85														
86	TOTAL	16,402	4,922,483				9,516					46,842,381	68,754,907	1.3968

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Page: 7

Estimated For The Period of : Dec-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	404	48,850	17.6	94.2	61.3	9,864	Heavy Oil BBLS ->	74,398	6,399,998	476,146	1,255,638	2.5704
2			2,279					Gas MCF ->	28,191	1,000,000	28,191	60,494	2.6539
3													
4	TRKY O 2	403	6,158	2.1	93.1	46.4	10,150	Heavy Oil BBLS ->	9,587	6,399,975	61,354	161,870	2.6284
5			0					Gas MCF ->	1,151	1,000,000	1,151	2,967	
6													
7	TRKY N 3	717	483,304	93.6	90.5	100.0	10,792	Nuclear MBTU ->	5,216,001	1,000,000	5,216,001	1,563,165	0.3234
8													
9	TRKY N 4	717	488,260	94.6	83.2	100.0	10,792	Nuclear MBTU ->	5,269,483	1,000,000	5,269,483	1,762,536	0.3610
10													
11	FT LAUD4	452	317,454	97.5	88.7	99.7	7,836	Gas MCF ->	2,487,664	1,000,000	2,487,664	6,329,432	1.9938
12													
13	FT LAUD5	452	317,112	97.4	93.5	99.6	7,836	Gas MCF ->	2,484,998	1,000,000	2,484,998	6,322,560	1.9938
14													
15	PT EVER1	212	6,643	4.4	92.9	55.1	11,080	Heavy Oil BBLS ->	11,295	6,399,996	72,285	184,730	2.7807
16			0					Gas MCF ->	1,325	1,000,000	1,325	3,341	
17													
18	PT EVER2	213	5,015	3.3	95.9	59.2	11,034	Heavy Oil BBLS ->	8,501	6,399,976	54,403	138,836	2.7685
19			0					Gas MCF ->	929	1,000,000	929	2,317	
20													
21	PT EVER3	398	115,592	40.5	87.3	62.8	10,019	Heavy Oil BBLS ->	180,107	6,400,000	1,152,685	2,949,365	2.5515
22			0					Gas MCF ->	5,455	1,000,000	5,455	13,860	
23													
24	PT EVER4	387	28,287	10.2	80.9	53.3	10,135	Heavy Oil BBLS ->	44,285	6,399,993	283,426	727,464	2.5717
25			0					Gas MCF ->	3,268	1,000,000	3,268	8,425	
26													
27	RIV 3	292	134,732	64.9	78.6	74.5	9,940	Heavy Oil BBLS ->	208,544	6,399,999	1,334,683	3,132,073	2.3247
28			1,720					Gas MCF ->	21,633	1,000,000	21,633	46,750	2.7175
29													
30	RIV 4	292	120,569	59.0	92.5	74.4	10,025	Heavy Oil BBLS ->	187,639	6,400,001	1,200,888	2,819,522	2.3385
31			3,522					Gas MCF ->	43,078	1,000,000	43,078	92,066	2.6142
32													

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Page: 8

Estimated For The Period of : Dec-97

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Cut 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)
33	ST LUC 1	853		0.0	72.7		0						
34													
35	ST LUC 2	726	496,518	95.0	82.6	100.0	10,799	Nuclear MBTU ->	5,362,076	1,000,000	5,362,076	1,832,114	0.3690
36													
37	CAP CN 1	400	125,878	44.7	92.5	62.9	9,660	Heavy Oil BBLS ->	188,859	6,400,000	1,208,696	2,994,085	2.3786
38			2,756					Gas MCF ->	33,928	1,000,000	33,928	73,014	2.6491
39													
40	CAP CN 2	400	70,709	24.6	89.3	64.2	9,609	Heavy Oil BBLS ->	105,773	6,400,000	676,947	1,678,337	2.3736
41			0					Gas MCF ->	2,484	1,000,000	2,484	6,405	
42													
43	SANFRD 3	147	376	0.4	74.2	76.7	10,221	Heavy Oil BBLS ->	582	6,400,447	3,726	9,373	2.4922
44			0					Gas MCF ->	118	1,000,000	118	305	
45													
46	SANFRD 4	394	54,153	20.3	90.9	61.5	9,923	Heavy Oil BBLS ->	82,994	6,399,998	531,161	1,336,214	2.4675
47			3,394					Gas MCF ->	39,886	1,000,000	39,886	85,476	2.5184
48													
49	SANFRD 5	394	85,531	30.9	92.5	67.0	9,820	Heavy Oil BBLS ->	130,362	6,399,998	834,318	2,098,063	2.4530
50			2,128					Gas MCF ->	26,497	1,000,000	26,497	57,441	2.6995
51													
52	PUTNAM 1	272	51,516	26.3	94.4	82.2	9,179	Gas MCF ->	472,877	1,000,000	472,877	1,199,082	2.3276
53													
54	PUTNAM 2	272	60,693	31.0	91.4	83.3	9,154	Gas MCF ->	555,577	1,000,000	555,577	1,406,412	2.3173
55													
56	MANATE 1	805	74,162	12.8	95.9	46.1	10,290	Heavy Oil BBLS ->	119,244	6,399,998	763,162	1,912,799	2.5792
57													
58	MANATE 2	805	59,179	10.2	90.6	55.9	10,332	Heavy Oil BBLS ->	95,535	6,399,998	611,425	1,533,248	2.5909
59													
60	FT MY 1	142	43,452	42.5	81.3	64.7	10,319	Heavy Oil BBLS ->	70,056	6,399,995	448,361	1,084,307	2.4954
61													
62	FT MY 2	415	230,257	77.1	82.9	79.2	9,413	Heavy Oil BBLS ->	338,649	6,399,999	2,167,354	5,239,438	2.2755
63													

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-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)
CUTLER 5	72	12	0.0	96.0	83.4	12,210	Gas MCF ->	148	1,000,000	148	378	3.1240
CUTLER 6	145	33	0.0	96.0	75.1	11,415	Gas MCF ->	379	1,000,000	379	969	2.9187
MARTIN 1	821	315	0.4	96.0	35.9	10,811	Heavy Oil BBLS ->	506	6,400,040	3,237	9,623	3.0559
		1,820					Gas MCF ->	19,837	1,000,000	19,837	50,854	2.7949
MARTIN 2	821	565	2.3	83.1	43.6	10,733	Heavy Oil BBLS ->	888	6,400,293	5,684	16,901	2.9892
		13,048					Gas MCF ->	140,437	1,000,000	140,437	350,817	2.6886
MARTIN 3	460	326,234	98.5	94.2	99.9	6,898	Gas MCF ->	2,250,329	1,000,000	2,250,329	5,725,798	1.7551
MARTIN 4	460	327,295	98.8	93.7	100.0	6,892	Gas MCF ->	2,255,586	1,000,000	2,255,586	5,739,262	1.7535
FM GT	636	0	0.0	95.0		0	Light Oil BBLS ->	0	4,000,000	0	2	
FL GT	792	41	0.0	92.0	84.2	15,195	Gas MCF ->	621	1,000,000	621	1,595	3.9093
PE GT	396	1	0.0	92.0		0	Gas MCF ->	12	1,000,000	12	30	4.2857
SJRPP 1O	116	83,555	0.0	94.2	99.9	9,389	Coal TONS ->	30,878	25,472,978	786,560	1,242,396	1.4869
SJRPP 2O	116	83,604	0.0	87.9	100.5	9,316	Coal TONS ->	30,655	25,472,970	780,874	1,233,413	1.4753
SCHER #4	605	410,086	94.1	90.8	94.1	10,270	Coal TONS ->	230,854	18,243,999	4,211,708	7,210,965	1.7584
TOTAL	16,402	4,686,808				9,472				44,393,050	71,706,527	1.5300

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Page: 10

Estimated For The Period of : Jan-98

	(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	404	14,497	9.6	94.2	36.6	10,793	Heavy Oil	BBLS ->	22,435	6,400,000	143,581	378,803	2.6131
2			14,346					Gas	MCF ->	167,723	1,000,000	167,723	371,172	2.5873
3														
4	TRKY O 2	403	14,694	12.4	93.1	34.3	10,961	Heavy Oil	BBLS ->	22,752	6,399,995	145,615	384,169	2.6146
5			22,597					Gas	MCF ->	263,118	1,000,000	263,118	582,279	2.5768
6														
7	TRKY N 3	717	506,776	95.0	90.5	100.0	10,792	Nuclear	MBTU ->	5,469,315	1,000,000	5,469,315	1,612,353	0.3182
8														
9	TRKY N 4	717	497,174	93.2	83.2	100.0	10,792	Nuclear	MBTU ->	5,365,685	1,000,000	5,365,685	1,771,213	0.3563
10														
11	FT LAUD4	452	315,844	93.9	88.7	98.8	7,851	Gas	MCF ->	2,479,696	1,000,000	2,479,696	5,487,568	1.7374
12														
13	FT LAUD5	452	325,010	96.6	93.5	99.0	7,841	Gas	MCF ->	2,548,471	1,000,000	2,548,471	5,639,765	1.7353
14														
15	PT EVER1	212	3,266	2.1	92.9	42.3	11,509	Heavy Oil	BBLS ->	5,735	6,400,024	36,707	94,795	2.9024
16			0					Gas	MCF ->	885	1,000,000	885	1,958	979.0000
17														
18	PT EVER2	213	3,030	1.9	95.9	38.5	11,717	Heavy Oil	BBLS ->	5,402	6,399,974	34,573	89,286	2.9467
19			0					Gas	MCF ->	929	1,000,000	929	2,056	
20														
21	PT EVER3	396	41,087	16.4	87.3	30.9	11,483	Heavy Oil	BBLS ->	71,001	6,400,002	454,408	1,173,512	2.8561
22			7,099					Gas	MCF ->	98,896	1,000,000	98,896	218,857	3.0831
23														
24	PT EVER4	387	24,454	13.1	80.9	27.2	11,629	Heavy Oil	BBLS ->	41,202	6,400,001	263,692	680,987	2.7847
25			13,296					Gas	MCF ->	175,300	1,000,000	175,300	387,940	2.9177
26														
27	RIV 3	292	125,609	57.8	78.6	66.9	10,001	Heavy Oil	BBLS ->	195,706	6,399,999	1,252,519	2,904,827	2.3126
28			0					Gas	MCF ->	3,701	1,000,000	3,701	8,189	
29														
30	RIV 4	292	106,798	49.2	92.5	61.4	10,134	Heavy Oil	BBLS ->	168,273	6,399,999	1,076,947	2,497,643	2.3387
31			0					Gas	MCF ->	5,327	1,000,000	5,327	11,789	
32														

Date: 5/13/97
Company: Florida Power & Light

Schedule E4
Page: 11

Estimated For The Period of : Jan-98

	(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)
33	ST LUC 1	853	505,658	79.7	72.7	100.0	10,799	Nuclear	MBTU ->	5,460,788	1,000,000	5,460,788	2,041,789	0.4038
34														
35	ST LUC 2	726	513,068	95.0	82.6	100.0	10,799	Nuclear	MBTU ->	5,540,812	1,000,000	5,540,812	1,862,2[illegible]7	0.3630
36														
37	CAP CN 1	400	66,164	32.9	92.5	45.5	10,070	Heavy Oil	BBLS ->	101,298	6,399,999	648,306	1,600,621	2.4192
38			31,659					Gas	MCF ->	336,779	1,000,000	336,779	745,292	2.3541
39														
40	CAP CN 2	400	33,471	33.0	89.3	56.6	10,033	Heavy Oil	BBLS ->	49,993	6,400,004	319,954	789,944	2.3601
41			64,786					Gas	MCF ->	665,839	1,000,000	665,839	1,473,503	2.2744
42														
43	SANFRD 3	147	2,072	7.4	74.2	48.3	11,242	Heavy Oil	BBLS ->	3,281	6,399,939	20,995	52,753	2.5464
44			5,967					Gas	MCF ->	69,380	1,000,000	69,380	153,539	2.5731
45														
46	SANFRD 4	394	11,972	21.9	90.9	38.6	10,834	Heavy Oil	BBLS ->	18,802	6,400,003	120,334	302,355	2.5256
47			52,196					Gas	MCF ->	574,857	1,000,000	574,857	1,272,160	2.4373
48														
49	SANFRD 5	394	22,121	28.5	92.5	46.1	10,603	Heavy Oil	BBLS ->	34,262	6,400,008	219,276	550,962	2.4907
50			61,390					Gas	MCF ->	666,220	1,000,000	666,220	1,474,346	2.4016
51														
52	PUTNAM 1	272	47,323	23.4	94.4	77.3	9,217	Gas	MCF ->	436,159	1,000,000	436,159	965,219	2.0396
53														
54	PUTNAM 2	272	59,791	29.5	91.4	77.5	9,177	Gas	MCF ->	548,693	1,000,000	548,693	1,214,257	2.0308
55														
56	MANATE 1	805	48,548	8.1	95.9	31.9	10,771	Heavy Oil	BBLS ->	81,703	6,400,007	522,902	1,317,100	2.7130
57														
58	MANATE 2	805	26,149	4.4	90.6	53.2	10,328	Heavy Oil	BBLS ->	42,198	6,400,002	270,069	680,257	2.6015
59														
60	FT MY 1	142	36,757	34.8	81.3	53.0	10,432	Heavy Oil	BBLS ->	59,914	6,399,995	383,449	920,664	2.5047
61														
62	FT MY 2	415	239,609	77.6	82.9	78.4	9,382	Heavy Oil	BBLS ->	351,269	6,400,001	2,248,122	5,397,750	2.2527
63														

23

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-98

	(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	119	0.2	96.0	55.8	13,376	Gas	MCF ->	1,587	1,000,000	1,587	3,512	2.9587
65														
66	CUTLER 6	145	334	0.3	96.0	76.7	11,793	Gas	MCF ->	3,938	1,000,000	3,938	8,715	2.6101
67														
68	MARTIN 1	821	1,032	0.6	96.0	37.9	10,822	Heavy Oil	BBLS ->	1,623	6,400,111	10,389	30,891	2.9924
69			2,716					Gas	MCF ->	30,173	1,000,000	30,173	66,774	2.4587
70														
71	MARTIN 2	821	906	1.3	83.1	32.2	11,170	Heavy Oil	BBLS ->	1,476	6,400,081	9,448	28,092	3.1010
72			7,274					Gas	MCF ->	81,915	1,000,000	81,915	181,279	2.4923
73														
74	MARTIN 3	460	334,382	97.7	94.2	99.2	6,903	Gas	MCF ->	2,308,151	1,000,000	2,308,151	5,107,937	1.5276
75														
76	MARTIN 4	460	336,559	98.3	93.7	99.4	6,896	Gas	MCF ->	2,320,816	1,000,000	2,320,816	5,135,965	1.5260
77														
78	FM GT	636	238	0.1	95.0	96.9	13,420	Light Oil	BBLS ->	547	5,830,075	3,191	15,527	6.5294
79														
80	FL GT	792	243	0.3	92.0	99.7	15,102	Light Oil	BBLS ->	602	5,830,317	3,512	18,474	7.6119
81			1,633					Gas	MCF ->	24,820	1,000,000	24,820	54,926	3.3627
82														
83	PE GT	396	787	0.3	92.0	99.9	16,336	Light Oil	BBLS ->	2,205	5,829,946	12,853	67,614	8.5892
84			9					Gas	MCF ->	152	1,000,000	152	336	3.7753
85														
86	SJRPP 1O	116	86,403	0.0	94.2	100.0	9,389	Coal	TONS ->	32,505	24,956,978	811,217	1,282,825	1.4847
87														
88	SJRPP 2O	116	85,621	99.6	87.9	99.6	9,315	Coal	TONS ->	31,957	24,957,033	797,557	1,261,224	1.4730
89														
90	SCHER #4	605	437,113	97.1	90.8	97.1	10,263	Coal	TONS ->	245,906	18,244,002	4,486,301	7,707,216	1.7632
91														
92	TOTAL	16,402	5,159,644				9,680					49,946,039	68,085,246	1.3196

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Page: 13

Estimated For The Period of : Feb-98

	(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	404	10,102	8.1	94.2	40.7	10,625	Heavy Oil BBLS ->	15,635	6,400,004	100,065	263,389	2.6072
2			11,811					Gas MCF ->	132,773	1,000,000	132,773	257,422	2.1795
3													
4	TRKY O 2	403	6,633	10.3	93.1	39.9	10,753	Heavy Oil BBLS ->	10,232	6,400,004	65,487	172,399	2.5993
5			21,370					Gas MCF ->	235,629	1,000,000	235,629	455,498	2.1315
6													
7	TRKY N 3	717	457,733	95.0	90.5	100.0	10,792	Nuclear MBTU ->	4,940,026	1,000,000	4,940,026	1,457,166	0.3183
8													
9	TRKY N 4	717	449,060	93.2	83.2	100.0	10,792	Nuclear MBTU ->	4,846,426	1,000,000	4,846,426	1,601,051	0.3565
10													
11	FT LAUD4	452	292,851	96.4	88.7	99.4	7,845	Gas MCF ->	2,297,369	1,000,000	2,297,369	4,340,069	1.4820
12													
13	FT LAUD5	452	295,641	97.3	93.5	99.6	7,836	Gas MCF ->	2,316,755	1,000,000	2,316,755	4,376,405	1.4803
14													
15	PT EVER1	212	840	0.6	92.9	65.3	10,676	Heavy Oil BBLS ->	1,404	6,399,900	8,983	23,021	2.7422
16			0					Gas MCF ->	148	1,000,000	148	271	
17													
18	PT EVER2	213	815	0.6	95.9	63.6	10,967	Heavy Oil BBLS ->	1,372	6,399,796	8,782	22,506	2.7618
19			0					Gas MCF ->	155	1,000,000	155	284	
20													
21	PT EVER3	396	71,413	27.4	87.3	46.6	10,458	Heavy Oil BBLS ->	115,083	6,399,999	736,531	1,888,573	2.6446
22			1,372					Gas MCF ->	24,668	1,000,000	24,668	49,077	3.5778
23													
24	PT EVER4	387	33,888	17.7	80.9	38.3	10,765	Heavy Oil BBLS ->	54,380	6,399,995	348,031	892,673	2.6342
25			12,110					Gas MCF ->	147,120	1,000,000	147,120	277,257	2.2895
26													
27	RIV 3	292	126,267	69.6	78.6	78.4	9,924	Heavy Oil BBLS ->	194,480	6,399,999	1,244,674	2,832,826	2.2435
28			10,342					Gas MCF ->	111,012	1,000,000	111,012	204,257	1.9750
29													
30	RIV 4	292	92,921	59.2	92.5	71.9	10,113	Heavy Oil BBLS ->	144,641	6,400,002	925,702	2,107,676	2.2683
31			23,236					Gas MCF ->	248,936	1,000,000	248,936	457,616	1.9694
32													

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-98

(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	544,555	95.0	72.7	100.0	10,799	Nuclear	MBTU ->	5,880,849	1,000,000	5,880,849	2,198,849	0.4038
ST LUC 2	726	463,417	95.0	82.6	100.0	10,799	Nuclear	MBTU ->	5,004,604	1,000,000	5,004,604	1,682,906	0.3632
CAP CN 1	400	64,159	35.2	92.5	52.2	9,943	Heavy Oil	BBLS ->	96,667	6,400,000	618,666	1,513,565	2.3591
		30,478					Gas	MCF ->	322,333	1,000,000	322,333	603,722	1.9809
CAP CN 2	400	46,424	46.3	89.3	62.9	9,930	Heavy Oil	BBLS ->	69,215	6,400,003	442,976	1,084,092	2.3352
		78,155					Gas	MCF ->	794,050	1,000,000	794,050	1,483,466	1.8981
SANFRD 3	147	409	4.1	74.2	56.4	11,049	Heavy Oil	BBLS ->	647	6,399,722	4,142	10,389	2.5407
		3,680					Gas	MCF ->	41,035	1,000,000	41,035	80,259	2.1810
SANFRD 4	394	4,587	16.6	90.9	44.1	10,680	Heavy Oil	BBLS ->	7,233	6,400,041	46,292	116,073	2.5308
		39,358					Gas	MCF ->	423,014	1,000,000	423,014	805,745	2.0472
SANFRD 5	394	17,001	28.8	92.5	53.9	10,395	Heavy Oil	BBLS ->	26,043	6,399,997	166,673	417,812	2.4576
		59,137					Gas	MCF ->	624,735	1,000,000	624,735	1,182,122	1.9990
PUTNAM 1	272	38,876	21.3	94.4	78.3	9,192	Gas	MCF ->	357,353	1,000,000	357,353	683,099	1.7571
PUTNAM 2	272	47,965	26.2	91.4	78.8	9,168	Gas	MCF ->	439,734	1,000,000	439,734	847,820	1.7676
MANATE 1	805	33,789	6.2	95.9	35.8	10,529	Heavy Oil	BBLS ->	55,587	6,399,998	355,755	895,225	2.6495
MANATE 2	805	13,263	2.5	90.6	51.3	10,323	Heavy Oil	BBLS ->	21,392	6,399,992	136,907	344,470	2.5972
FT MY 1	142	35,547	37.3	81.3	57.4	10,377	Heavy Oil	BBLS ->	57,633	6,399,999	368,852	872,991	2.4559
FT MY 2	415	223,277	80.1	82.9	81.9	9,376	Heavy Oil	BBLS ->	327,116	6,400,000	2,093,543	4,954,722	2.2191

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-98

	(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	9	0.0	96.0	86.8	12,210	Gas	MCF ->	107	1,000,000	107	196	2.2273
65														
66	CUTLER 6	145	21	0.0	96.0	82.7	11,415	Gas	MCF ->	244	1,000,000	244	449	2.0981
67														
68	MARTIN 1	821	317	0.3	96.0	39.0	10,806	Heavy Oil	BBLS ->	505	6,400,277	3,232	9,609	3.0331
69			1,578					Gas	MCF ->	17,248	1,000,000	17,248	31,683	2.0073
70														
71	MARTIN 2	821	268	0.4	83.1	48.1	10,611	Heavy Oil	BBLS ->	420	6,400,048	2,686	7,987	2.9791
72			2,113					Gas	MCF ->	22,578	1,000,000	22,578	41,476	1.9631
73														
74	MARTIN 3	460	303,915	98.3	94.2	99.7	6,893	Gas	MCF ->	2,094,929	1,000,000	2,094,929	3,959,371	1.3028
75														
76	MARTIN 4	460	305,252	98.7	93.7	99.8	6,893	Gas	MCF ->	2,104,009	1,000,000	2,104,009	3,976,880	1.3028
77														
78	FM GT	636	0	0.0	95.0		0	Light Oil	BBLS ->	0	8,000,000	1	4	4.0000
79														
80	FL GT	792	37	0.0	92.0	86.6	15,195	Gas	MCF ->	561	1,000,000	561	1,031	2.7940
81														
82	PE GT	396	1	0.0	92.0		0	Gas	MCF ->	16	1,000,000	16	30	3.3333
83														
84	SJRPP 1O	116	78,076	0.0	94.2	100.0	9,389	Coal	TONS ->	29,375	24,937,969	732,563	1,159,753	1.4854
85														
86	SJRPP 2O	116	77,469	99.8	87.9	99.8	9,316	Coal	TONS ->	28,919	24,937,957	721,176	1,141,726	1.4738
87														
88	SCHER #4	605	399,936	98.4	90.8	98.4	10,266	Coal	TONS ->	225,041	18,244,001	4,105,643	7,065,715	1.7667
89														
90	TOTAL	16,402	4,831,470				9,659					46,665,773	58,852,673	1.2181

Date: 5/13/97
Company: Florida Power & Light

Schedule E4
Page: 16

Estimated For The Period of : Mar-98

	(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	404	33,597	19.1	94.2	64.6	9,953	Heavy Oil	BBLS ->	50,493	6,400,004	323,154	840,920	2.5030
2			23,938					Gas	MCF ->	249,507	1,000,000	249,507	493,712	2.0625
3														
4	TRKY O 2	403	18,023	23.8	93.1	63.3	10,108	Heavy Oil	BBLS ->	27,021	6,399,999	172,936	450,022	2.4970
5			53,463					Gas	MCF ->	549,645	1,000,000	549,645	1,087,587	2.0343
6														
7	TRKY N 3	717	506,776	95.0	90.5	100.0	10,792	Nuclear	MBTU ->	5,469,315	1,000,000	5,469,315	1,614,400	0.3186
8														
9	TRKY N 4	717	497,174	93.2	83.2	100.0	10,792	Nuclear	MBTU ->	5,365,685	1,000,000	5,365,685	1,773,758	0.3568
10														
11	FT LAUD4	452	166,858	49.6	88.7	99.6	7,854	Gas	MCF ->	1,310,509	1,000,000	1,310,509	2,547,429	1.5267
12														
13	FT LAUD5	452	328,936	97.8	93.5	99.9	7,832	Gas	MCF ->	2,576,155	1,000,000	2,576,155	5,051,014	1.5356
14														
15	PT EVER1	212	9,438	6.0	92.9	53.7	11,046	Heavy Oil	BBLS ->	16,060	6,400,019	102,784	259,169	2.7460
16			0					Gas	MCF ->	1,472	1,000,000	1,472	2,912	
17														
18	PT EVER2	213	6,864	4.3	95.9	46.4	11,348	Heavy Oil	BBLS ->	11,929	6,399,998	76,348	192,509	2.8045
19			0					Gas	MCF ->	1,548	1,000,000	1,548	3,064	
20														
21	PT EVER3	396	2,400	0.8	87.3	30.3	11,520	Heavy Oil	BBLS ->	4,224	6,399,938	27,036	69,287	2.8874
22			0					Gas	MCF ->	606	1,000,000	606	1,113	
23														
24	PT EVER4	387	89,995	34.2	80.9	62.5	9,968	Heavy Oil	BBLS ->	138,403	6,400,002	885,781	2,233,580	2.4819
25			8,351					Gas	MCF ->	94,525	1,000,000	94,525	184,000	2.2032
26														
27	RIV 3	292	5,801	3.6	78.6	74.5	10,065	Heavy Oil	BBLS ->	8,939	6,400,000	57,206	129,935	2.2401
28			2,064					Gas	MCF ->	21,943	1,000,000	21,943	40,310	1.9532
29														
30	RIV 4	292	162,185	79.5	92.5	91.3	9,894	Heavy Oil	BBLS ->	249,310	6,400,001	1,595,583	3,524,904	2.1734
31			10,533					Gas	MCF ->	113,290	1,000,000	113,290	215,322	2.0442
32														

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Page: 17

Estimated For The Period of : Mar-98

	(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)
33	ST LUC 1	853	602,900	95.0	72.7	100.0	10,799	Nuclear	MBTU ->	6,510,940	1,000,000	6,510,940	2,437,844	0.4044
34														
35	ST LUC 2	726	513,068	95.0	82.6	100.0	10,799	Nuclear	MBTU ->	5,540,812	1,000,000	5,540,812	1,864,823	0.3635
36														
37	CAP CN 1	400	140,899	52.6	92.5	72.4	9,585	Heavy Oil	BBLS ->	208,604	6,400,000	1,335,062	3,164,678	2.2461
38			15,736					Gas	MCF ->	166,346	1,000,000	166,346	319,192	2.0285
39														
40	CAP CN 2	400	114,348	63.5	89.3	79.5	9,625	Heavy Oil	BBLS ->	167,777	6,399,999	1,073,774	2,545,179	2.2258
41			74,616					Gas	MCF ->	745,072	1,000,000	745,072	1,454,505	1.9493
42														
43	SANFRD 3	147	151	1.4	74.2	69.9	10,701	Heavy Oil	BBLS ->	234	6,399,230	1,496	3,700	2.4585
44			1,354					Gas	MCF ->	14,606	1,000,000	14,606	28,894	2.1337
45														
46	SANFRD 4	394	15,111	38.0	90.9	66.8	10,176	Heavy Oil	BBLS ->	22,864	6,400,004	146,327	362,059	2.3959
47			96,391					Gas	MCF ->	988,343	1,000,000	988,343	1,954,565	2.0277
48														
49	SANFRD 5	394	44,338	46.0	92.5	71.9	10,044	Heavy Oil	BBLS ->	66,817	6,400,002	427,628	1,058,192	2.3867
50			90,498					Gas	MCF ->	926,696	1,000,000	926,696	1,827,767	2.0197
51														
52	PUTNAM 1	272	68,661	33.9	94.4	85.7	9,108	Gas	MCF ->	625,369	1,000,000	625,369	1,227,421	1.7877
53														
54	PUTNAM 2	272	84,175	41.6	91.4	85.6	9,100	Gas	MCF ->	765,963	1,000,000	765,963	1,500,452	1.7825
55														
56	MANATE 1	805	79,400	13.3	95.9	52.5	10,188	Heavy Oil	BBLS ->	126,394	6,399,997	808,918	2,011,954	2.5339
57														
58	MANATE 2	805	8,432	1.4	90.6	50.4	10,263	Heavy Oil	BBLS ->	13,521	6,400,043	86,537	215,239	2.5528
59														
60	FT MY 1	142	57,317	54.3	81.3	72.5	10,175	Heavy Oil	BBLS ->	91,121	6,400,002	583,173	1,330,586	2.3215
61														
62	FT MY 2	415	263,098	85.2	82.9	88.2	9,376	Heavy Oil	BBLS ->	385,439	6,400,001	2,466,811	5,635,305	2.1419
63														

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Page: 18

Estimated For The Period of : Mar-98

	(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	73	0.1	96.0	41.8	14,626	Gas MCF ->	1,063	1,000,000	1,063	2,103	2.8927
65													
66	CUTLER 6	145	260	0.2	96.0	50.5	12,250	Gas MCF ->	3,190	1,000,000	3,190	6,313	2.4243
67													
68	MARTIN 1	821	1,643	2.1	96.0	38.1	10,812	Heavy Oil BBLS ->	2,634	6,400,084	16,856	50,119	3.0510
69			11,056					Gas MCF ->	120,453	1,000,000	120,453	238,377	2.1560
70													
71	MARTIN 2	821	2,676	3.2	83.1	40.6	10,754	Heavy Oil BBLS ->	4,257	6,400,023	27,245	81,010	3.0266
72			16,652					Gas MCF ->	180,601	1,000,000	180,601	357,408	2.1464
73													
74	MARTIN 3	460	337,335	98.6	94.2	100.0	6,891	Gas MCF ->	2,324,671	1,000,000	2,324,671	4,557,927	1.3512
75													
76	MARTIN 4	460	338,626	98.9	93.7	100.0	6,891	Gas MCF ->	2,333,564	1,000,000	2,333,564	4,575,367	1.3512
77													
78	FM GT	636	4	0.0	95.0	81.8	13,420	Light Oil BBLS ->	10	5,821,053	55	269	6.5610
79													
80	FL GT	792	991	0.2	92.0	97.6	15,195	Gas MCF ->	15,053	1,000,000	15,053	29,789	3.0072
81													
82	PE GT	396	22	0.0	92.0	89.7	17,143	Gas MCF ->	374	1,000,000	374	739	3.3899
83													
84	SJRPP 1O	116	86,435	0.0	94.2	100.0	9,389	Coal TONS ->	32,543	24,937,992	811,550	1,283,345	1.4848
85													
86	SJRPP 2O	116	5,547	6.5	87.9	100.0	9,316	Coal TONS ->	2,072	24,937,796	51,676	81,762	1.4740
87													
88	SCHER #4	605	328,924	73.1	90.8	98.5	10,268	Coal TONS ->	185,120	18,243,997	3,377,325	5,819,911	1.7694
89													
90	TOTAL	16,402	5,327,132				9,662				51,472,571	66,741,741	1.2529

Estimated For The Period of : Oct-97 Thru Mar-98

	(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	404	159,181	22.0	0.0	63.3	10,139	Heavy Oil BBLS ->	241,640	6,400,000	1,546,493	4,062,982	2.5524
2			226,939					Gas MCF ->	2,368,420	1,000,000	2,368,420	5,056,344	2.2281
3													
4	TRKY O 2	403	65,022	17.6	0.0	58.7	10,306	Heavy Oil BBLS ->	99,035	6,399,997	633,821	1,664,069	2.5592
5			243,904					Gas MCF ->	2,549,834	1,000,000	2,549,834	5,109,905	2.0950
6													
7	TRKY N 3	717	2,917,866	93.7	0.0	99.5	10,844	Nuclear MBTU ->	31,640,543	1,000,000	31,640,543	9,404,369	0.3223
8													
9	TRKY N 4	717	2,613,342	83.9	0.0	99.8	10,811	Nuclear MBTU ->	28,253,255	1,000,000	28,253,255	9,381,944	0.3590
10													
11	FT LAUD4	452	1,727,115	88.0	0.0	98.7	7,851	Gas MCF ->	13,560,372	1,000,000	13,560,372	28,202,580	1.6329
12													
13	FT LAUD5	452	1,782,174	90.8	0.0	98.8	7,846	Gas MCF ->	13,983,206	1,000,000	13,983,206	28,961,589	1.6251
14													
15	PT EVER1	212	25,208	4.6	0.0	61.6	11,139	Heavy Oil BBLS ->	42,921	6,400,019	274,693	694,668	2.7557
16			17,250					Gas MCF ->	198,233	1,000,000	198,233	464,584	2.6933
17													
18	PT EVER2	213	21,780	3.8	0.0	57.2	11,283	Heavy Oil BBLS ->	37,459	6,399,992	239,734	605,064	2.7780
19			12,950					Gas MCF ->	152,121	1,000,000	152,121	356,623	2.7538
20													
21	PT EVER3	396	389,595	34.8	0.0	61.4	10,240	Heavy Oil BBLS ->	613,401	6,400,000	3,925,766	9,918,183	2.5458
22			208,738					Gas MCF ->	2,200,930	1,000,000	2,200,930	5,193,450	2.4880
23													
24	PT EVER4	387	186,918	18.6	0.0	52.5	10,418	Heavy Oil BBLS ->	294,114	6,400,000	1,882,328	4,783,465	2.5591
25			126,397					Gas MCF ->	1,381,691	1,000,000	1,381,691	3,126,264	2.4734
26													
27													
28	RIV 3	2[illegible]2	715,191	58.7	0.0	77.9	9,932	Heavy Oil BBLS ->	1,105,468	6,400,000	7,074,992	16,264,477	2.2741
29			29,950					Gas MCF ->	326,020	1,000,000	326,020	633,941	2.1167
30													

Estimated For The Period of : Oct-97 Thru Mar-98

	(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)
31	RIV 4	292	698,303	61.8	0.0	76.6	10,039	Heavy Oil BBLS ->	1,085,824	6,400,000	6,949,274	15,855,514	2.2706
32			85,131					Gas MCF ->	915,856	1,000,000	915,856	1,783,647	2.0952
33													
34	ST LUC 1	853	2,054,827	55.5	0.0	99.7	10,826	Nuclear MBTU ->	22,244,828	1,000,000	22,244,828	8,334,801	0.4056
35			0						0		0	0	0.0000
36													
37	ST LUC 2	726	2,988,051	94.7	0.0	99.7	10,820	Nuclear MBTU ->	32,330,331	1,000,000	32,330,331	10,955,986	0.3667
38													
39	CAP CN 1	400	655,451	45.6	0.0	63.9	9,732	Heavy Oil BBLS ->	980,404	6,400,000	6,274,586	15,211,999	2.3208
40			136,833					Gas MCF ->	1,435,819	1,000,000	1,435,819	2,891,161	2.1129
41													
42	CAP CN 2	400	497,434	48.6	0.0	71.5	9,746	Heavy Oil BBLS ->	738,055	6,400,000	4,723,554	11,424,473	2.2967
43			346,197					Gas MCF ->	3,498,713	1,000,000	3,498,713	6,976,179	2.0151
44													
45	SANFRD 3	147	3,745	3.3	0.0	58.7	10,967	Heavy Oil BBLS ->	5,900	6,399,976	37,757	94,464	2.5221
46			17,645					Gas MCF ->	196,838	1,000,000	196,838	390,261	2.2117
47													
48													
49	SANFRD 4	394	99,530	23.7	0.0	59.7	10,295	Heavy Oil BBLS ->	152,635	6,400,002	976,866	2,444,114	2.4557
50			306,266					Gas MCF ->	3,200,747	1,000,000	3,200,747	6,300,915	2.0573
51													
52	SANFRD 5	394	244,201	32.0	0.0	64.5	10,132	Heavy Oil BBLS ->	371,389	6,400,000	2,376,887	5,923,441	2.4256
53			303,133					Gas MCF ->	3,168,731	1,000,000	3,168,731	6,306,688	2.0805
54													
55	PUTNAM 1	272	386,878	32.7	0.0	84.3	9,130	Gas MCF ->	3,532,109	1,000,000	3,532,109	7,150,010	1.8481
56													
57	PUTNAM 2	272	461,013	39.0	0.0	84.4	9,117	Gas MCF ->	4,202,847	1,000,000	4,202,847	8,522,401	1.8486
58													
59	MANATE 1	805	419,677	12.0	0.0	48.8	10,267	Heavy Oil BBLS ->	673,224	6,399,999	4,308,630	10,707,200	2.5513
60													

Date: 5/13/97

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-97 Thru Mar-98

(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)
MANATE 2	805	317,500	9.1	0.0	63.2	10,205	Heavy Oil BBLS ->	506,253	6,400,001	3,240,018	8,021,020	2.5263
FT MY 1	142	263,551	42.7	0.0	65.4	10,295	Heavy Oil BBLS ->	423,949	6,400,000	2,713,272	6,383,126	2.4220
FT MY 2	415	1,424,370	79.0	0.0	83.8	9,390	Heavy Oil BBLS ->	2,089,815	6,400,000	13,374,817	31,529,856	2.2136
CUTLER 5	72	251	0.1	0.0	58.0	13,492	Gas MCF ->	3,381	1,000,000	3,381	7,040	2.8093
CUTLER 6	145	762	0.1	0.0	65.6	11,899	Gas MCF ->	9,061	1,000,000	9,061	18,789	2.4674
MARTIN 1	821	4,481	0.8	0.0	39.0	10,880	Heavy Oil BBLS ->	7,187	6,400,056	45,994	136,758	3.0523
		24,039					Gas MCF ->	264,280	1,000,000	264,280	524,316	2.1811
MARTIN 2	821	8,160	2.2	0.0	42.4	10,884	Heavy Oil BBLS ->	13,125	6,400,043	83,998	249,760	3.0608
		71,952					Gas MCF ->	787,948	1,000,000	787,948	1,603,174	2.2281
MARTIN 3	460	1,946,712	97.4	0.0	98.8	6,912	Gas MCF ->	13,455,222	1,000,000	13,455,222	27,883,725	1.4323
MARTIN 4	460	1,953,336	97.8	0.0	98.8	6,909	Gas MCF ->	13,496,383	1,000,000	13,496,383	27,970,194	1.4319
FM GT	636	242	0.0	0.0	100.0	13,420	Light Oil BBLS ->	557	5,829,715	3,249	15,810	6.5304
FL GT	792	2,812	0.1	0.0	100.0	15,138	Gas MCF ->	42,724	1,000,000	42,724	90,318	3.2124
		243					Light Oil BBLS ->	602	5,830,317	3,512	18,474	7.6119
PE GT	396	34	0.0	0.0	100.0	16,362	Gas MCF ->	585	1,000,000	585	1,191	3.4927
		787					Light Oil BBLS ->	2,205	5,829,946	12,853	67,614	8.5892
SJRPP 1O	116	504,386	100.1	0.0	100.0	9,407	Coal TONS ->	190,672	24,883,532	4,744,590	7,545,774	1.4960

Date: 5/13/97
Company: Florida Power & Light

Schedule E4
Page: 22

Estimated For The Period of : Oct-97 Thru Mar-98

	(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)
92	SJRPP 20	116	422,525	83.9	0.0	99.8	9,336	Coal	TONS ->	158,603	24,872,685	3,944,870	6,280,922	1.4865
93														
94	SCHER #4	605	2,417,630	92.0	0.0	96.2	10,283	Coal	TONS ->	1,362,722	18,243,999	24,861,505	42,663,467	1.7647
95														
96	TOTAL	16,402	30,537,607				9,616					293,655,082	416,169,085	1.3628

Date:5/13/97
Company: Florida Power & Light

Schedule: E5
Page : 1

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : October 1997 thru March 1998

Line	Item	Unit	October 1997	November 1997	December 1997	January 1998	February 1998	March 1998	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	1,830,524	1,461,415	1,856,408	1,175,227	1,148,760	1,739,149	9,211,483
3	Unit Cost	($/BBLS)	15.4360	15.4816	16.2243	15.4540	15.0998	14.6945	15.4225
4	Amount	($)	28,256,000	22,625,000	30,119,000	18,162,000	17,346,000	25,556,000	142,064,000
5									
6	Burned:								
7	Units	(BBLS)	1,988,069	1,561,882	1,857,802	1,278,327	1,199,685	1,596,040	9,481,795
8	Unit Cost	($/BBLS)	15.2505	15.3085	15.7616	15.5480	15.3624	15.1364	15.3953
9	Amount	($)	30,318,900	23,910,090	29,281,885	19,875,414	18,429,995	24,158,344	145,974,628
10									
11	Ending Inventory:								
12	Units	(BBLS)	3,596,276	3,495,810	3,494,415	3,391,316	3,340,393	3,483,504	3,483,504
13	Unit Cost	($/BBLS)	16.3365	16.4386	16.6844	16.6864	16.6161	16.3347	16.3347
14	Amount	($)	58,750,513	57,466,334	58,302,261	56,588,607	55,504,277	56,902,025	56,902,025
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)	0	0	0	3,354	0	9	3,363
26	Unit Cost	($/BBLS)				30.2967		29.8889	30.2997
27	Amount	($)	8	0	2	101,615	4	269	101,898
28									
29	Ending Inventory:								
30	Units	(BBLS)	150,075	150,075	150,075	146,721	146,721	146,711	146,711
31	Unit Cost	($/BBLS)	30.3423	30.3423	30.3423	30.3433	30.3433	30.3435	30.3435
32	Amount	($)	4,553,616	4,553,616	4,553,614	4,451,999	4,451,995	4,451,725	4,451,725
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	79,555	52,203	49,600	57,299	56,702	40,632	335,991
39	Unit Cost	($/Tons)	39.8341	39.8445	39.0927	39.4597	39.5048	39.4024	39.5546
40	Amount	($)	3,169,000	2,080,000	1,939,000	2,261,000	2,240,000	1,601,000	13,290,000
41									
42	Burned:								
43	Units	(Tons)	64,419	65,952	61,533	64,462	58,294	34,615	349,275
44	Unit Cost	($/Tons)	39.3461	39.5078	40.2355	39.4668	39.4806	39.4369	39.5868
45	Amount	($)	2,534,638	2,605,617	2,475,808	2,544,047	2,301,479	1,365,107	13,826,695
46									
47	Ending Inventory:								
48	Units	(Tons)	92,119	78,370	66,437	59,274	57,682	63,699	63,699
49	Unit Cost	($/Tons)	39.4551	39.6673	38.7183	38.6209	38.6232	38.6778	38.6778
50	Amount	($)	3,634,566	3,108,723	2,572,327	2,289,218	2,227,863	2,463,740	2,463,740
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	6,582,764	4,512,252	4,565,743	5,127,203	4,795,892	3,388,002	28,971,856
57	Unit Cost	($/MBTU)	1.7130	1.7151	1.7110	1.7249	1.7261	1.7279	1.7190
58	Amount	($)	11,276,000	7,739,000	7,812,000	8,844,000	8,278,000	5,854,000	49,803,000
59									
60	Burned:								
61	Units	(MBTU)	4,356,485	4,324,047	4,211,700	4,486,309	4,105,848	3,377,329	24,861,518
62	Unit Cost	($/MBTU)	1.7110	1.7126	1.7121	1.7179	1.7210	1.7232	1.7160
63	Amount	($)	7,454,154	7,405,506	7,210,965	7,707,216	7,065,715	5,819,911	42,663,467
64									
65	Ending Inventory:								
66	Units	(MBTU)	5,610,103	5,798,308	6,152,351	6,793,245	7,483,468	7,494,161	7,494,161
67	Unit Cost	($/MBTU)	1.7111	1.7129	1.7121	1.7179	1.7214	1.7236	1.7236
68	Amount	($)	9,599,167	9,932,173	10,533,194	11,670,403	12,882,397	12,916,954	12,916,954
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	18,775,819	14,485,609	10,821,613	13,741,064	12,695,710	14,074,417	84,593,932
75	Unit Cost	($/MCF)	2.4479	2.6661	3.4124	2.8977	2.5479	2.6183	2.7251
76	Amount	($)	45,960,550	38,620,430	36,927,040	39,817,450	32,347,560	36,850,390	230,523,420
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	16,850,334	16,375,812	15,847,580	21,836,600	20,671,905	22,886,752	114,468,983
83	Unit Cost	($/MBTU)	0.3368	0.3252	0.3255	0.3337	0.3357	0.3360	0.3326
84	Amount	($)	5,675,247	5,325,619	5,157,815	7,287,622	6,939,972	7,690,825	38,077,100

Date:5/13/97
Company: Florida Power & Light

Schedule: E6
Page : 1

POWER SOLD

Estimated For the Period of : October 1997 Thru March 1998

(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 1997		C	55,807		55,807	2.461	3.295	1,373,422
		OS	28,360		28,360	2.461	3.295	697,928
		S			0			0
	St.Lucie Rel.		29,918		29,918	0.412	0.412	123,360
	80% of Gain							372,347
Total			114,085	0	114,085	1.924	2.539	2,567,057
November 1997		C	183,674		183,674	2.354	3.058	4,323,686
		OS	54,377		54,377	2.354	3.058	1,280,035
		S			0			0
	St.Lucie Rel.		0		0	0.000	0.000	0
	80% of Gain							1,034,452
Total			238,051	0	238,051	2.354	3.058	6,638,173
December 1997		C	129,744		129,744	2.520	3.144	3,269,537
		OS	30,309		30,309	2.520	3.144	763,799
		S			0			0
	St.Lucie Rel.		0		0	0.000	0.000	0
	80% of Gain							647,679
Total			160,053	0	160,053	2.520	3.144	4,681,015
January 1998		C	141,250		141,250	2.358	2.938	3,330,672
		OS	31,910		31,910	2.358	2.938	752,440
		S			0			0
	St.Lucie Rel.		37,662		37,662	0.406	0.406	152,970
	80% of Gain							655,400
Total			210,822	0	210,822	2.009	2.486	4,891,482
February 1998		C	145,907		145,907	2.287	2.833	3,336,894
		OS	78,769		78,769	2.287	2.833	1,801,447
		S			0			0
	St.Lucie Rel.		40,559		40,559	0.404	0.404	163,770
	80% of Gain							637,322
Total			265,235	0	265,235	1.999	2.462	5,939,433
March 1998		C	158,054		158,054	2.237	2.795	3,535,672
		OS	78,132		78,132	2.237	2.795	1,747,808
		S			0			0
	St.Lucie Rel.		44,904		44,904	0.404	0.404	181,600
	80% of Gain							705,554
Total			281,090	0	281,090	1.944	2.413	6,170,634
Period Total		C	814,436		814,436	2.354	2.976	19,169,883
		OS	301,857		301,857	2.333	2.949	7,043,457
		S	0		0			0
	St.Lucie Rel.		153,043		153,043	0.406	0.406	621,700
	80% of Gain							4,052,754
Total			1,269,336	0	1,269,336	2.114	2.433	30,887,794

Date: 5/13/97
Company: Florida Power & Light

Schedule: E7
Page : 1

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : October 1997 thru March 1998

(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)
1997 October	Sou. Co. (UPS + R)		381,052			381,052	1.733		6,605,220
	St. Lucie Rel.		42,784			42,784	0.373		159,600
	SJRPP		250,968			250,968	1.534		3,849,670
Total			674,804			674,804	1.573		10,614,490
1997 November	Sou. Co. (UPS + R)		377,634			377,634	1.739		6,566,680
	St. Lucie Rel.		44,901			44,901	0.369		165,500
	SJRPP		259,333			259,333	1.520		3,941,280
Total			681,868			681,868	1.565		10,673,460
1997 December	Sou. Co. (UPS + R)		428,950			428,950	1.746		7,489,730
	St. Lucie Rel.		43,452			43,452	0.369		160,300
	SJRPP		250,749			250,749	1.441		3,613,870
Total			723,151			723,151	1.558		11,263,900
1998 January	Sou. Co. (UPS + R)		504,579			504,579	1.812		9,145,350
	St. Lucie Rel.		44,901			44,901	0.363		163,000
	SJRPP		256,440			256,440	1.479		3,791,560
Total			805,920			805,920	1.625		13,099,910
1998 February	Sou. Co. (UPS + R)		467,338			467,338	1.803		8,425,610
	St. Lucie Rel.		40,556			40,556	0.363		147,300
	SJRPP		232,973			232,973	1.480		3,448,500
Total			740,867			740,867	1.623		12,021,410
1998 March	Sou. Co. (UPS + R)		490,569			490,569	1.797		8,813,370
	St. Lucie Rel.		44,901			44,901	0.363		163,200
	SJRPP		137,973			137,973	1.483		2,046,530
Total			673,443			673,443	1.637		11,023,100
Period Total	Sou. Co. (UPS + R)		2,650,122			2,650,122	1.775		47,045,960
	St. Lucie Rel.		261,495			261,495	0.367		958,900
	SJRPP		1,388,436			1,388,436	1.490		20,691,410
Total			4,300,053			4,300,053	1.598		68,696,270

Date: 5/13/97
Company: Florida Power & Light

Schedule: E8
Page : 1

Energy Payment to Qualifying Facilities

Estimated for the Period of : October 1997 thru March 1998

(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)
1997 October	Qual. Facilities		650,418			650,418	1.872	1.872	12,176,373
Total			650,418			650,418	1.872	1.872	12,176,373
1997 November	Qual. Facilities		472,260			472,260	1.941	1.941	9,167,575
Total			472,260			472,260	1.941	1.941	9,167,575
1997 December	Qual. Facilities		670,102			670,102	1.849	1.849	12,393,309
Total			670,102			670,102	1.849	1.849	12,393,309
1998 January	Qual. Facilities		678,427			678,427	1.813	1.813	12,299,565
Total			678,427			678,427	1.813	1.813	12,299,565
1998 February	Qual. Facilities		550,524			550,524	1.792	1.792	9,863,984
Total			550,524			550,524	1.792	1.792	9,863,984
1998 March	Qual. Facilities		604,053			604,053	1.808	1.808	10,924,232
Total			604,053			604,053	1.808	1.808	10,924,232
Period Total	Qual. Facilities		3,625,783			3,625,783	1.843	1.843	66,825,038
Total			3,625,783			3,625,783	1.843	1.843	66,825,038

Economy Energy Purchases

Estimated For the Period of : October 1997 Thru March 1998

(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	341,805	1.824	6,234,510	2.126	7,266,760	1,032,250
1997	Non-Florida	C	207,742	2.124	4,413,340	2.426	5,040,719	627,379
Total			549,546	1.938	10,647,850	2.240	12,307,479	1,659,629
November	Florida	C	493,411	1.824	8,999,830	2.126	10,489,932	1,490,102
1997	Non-Florida	C	155,807	2.101	3,273,560	2.403	3,744,097	470,537
Total			649,218	1.890	12,273,390	2.192	14,234,029	1,960,639
December	Florida	C	352,318	1.824	6,426,320	2.196	7,736,945	1,310,625
1997	Non-Florida	C	103,215	2.076	2,142,250	2.448	2,526,211	383,961
Total			455,534	1.881	8,568,570	2.253	10,263,156	1,694,586
January	Florida	C	181,270	1.824	3,306,370	2.101	3,808,488	502,118
1998	Non-Florida	C	70,401	2.112	1,486,860	2.389	1,681,870	195,010
Total			251,671	1.905	4,793,230	2.182	5,490,358	697,128
February	Florida	C	219,679	1.824	4,006,960	2.118	4,652,817	645,857
1998	Non-Florida	C	23,862	2.131	508,510	2.425	578,665	70,155
Total			243,542	1.854	4,515,470	2.148	5,231,482	716,012
March	Florida	C	200,703	1.824	3,660,830	2.115	4,244,877	584,047
1998	Non-Florida	C	42,658	2.131	909,240	2.422	1,033,375	124,135
Total			243,361	1.878	4,570,070	2.169	5,278,252	708,182
Period	Florida	C	1,789,187	1.824	32,634,820	2.135	38,199,819	5,564,999
Total	Non-Florida	C	603,685	2.109	12,733,760	2.419	14,604,937	1,871,177
Total			2,392,872	1.896	45,368,580	2.207	52,804,756	7,436,176

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	APRIL 97 - SEPT 97	OCT 97 - MARCH 98	DIFFERENCE $	DIFFERENCE %
BASE	$47.46	$47.46	0	0.00%
FUEL	$21.96	$16.46	-5.5	-25.05%
CONSERVATION	$2.62	$2.62	0	0.00%
CAPACITY PAYMENT	$5.03	$6.74	1.71	34.00%
ENVIRONMENTAL	$0.17	$0.31	0.14	82.35%
SUBTOTAL	$77.24	$73.59	-3.65	-4.73%
GROSS RECEIPTS TAX	$0.79	$0.75	($0.04)	-5.06%
TOTAL	$78.03	$74.34	($3.69)	-4.73%

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

Line		PERIOD: OCT - MAR 1994 - 1995 (COLUMN 1)	OCT - MAR 1995 - 1996 (COLUMN 2)	OCT - MAR 1996 - 1997 (COLUMN 3)	OCT - MAR 1997 - 1998 (COLUMN 4)	DIFFERENCE (%) FROM PRIOR PERIOD: (COLUMN 2) change from (COLUMN 1)	(COLUMN 3) change from (COLUMN 2)	(COLUMN 4) change from (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	*HEAVY OIL	156,775,167	78,472,605	107,489,520	145,974,660	(50.0)	36.2	35.8
2	*LIGHT OIL	1,004,742	122,299	23,390	101,610	(87.8)	(80.9)	334.4
3	COAL	43,732,846	56,397,278	47,257,830	56,490,150	29.0	(16.2)	19.5
4	GAS	168,519,623	238,228,990	270,201,220	230,522,520	41.9	14.4	(14.7)
5	NUCLEAR	47,002,153	45,307,764	44,545,480	38,077,100	(3.6)	(1.7)	(14.5)
6	OTHER (ORIMULSION)	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	417,030,531	417,528,933	469,487,540	471,166,040	0.1	12.5	0.4
	SYSTEM NET GENERATION (MWH)							
8	*HEAVY OIL	7,416,684	3,342,179	4,203,307	6,199,298	(54.9)	25.8	47.5
9	*LIGHT OIL	10,844	1,807	378	1,268	(83.3)	(79.1)	234.1
10	COAL	2,720,369	3,290,689	2,769,645	3,344,840	21.0	(15.9)	20.8
11	GAS	8,277,330	11,584,421	11,506,586	10,418,300	40.0	(0.7)	(9.5)
12	NUCLEAR	9,765,442	10,427,461	11,838,590	10,574,066	6.8	13.5	(10.7)
13	OTHER (ORIMULSION)		0	0	0	0.0	0.0	0.0
14	TOTAL (MWH)	28,184,275	28,646,557	30,317,375	30,537,574	1.6	5.8	0.7
	UNITS OF FUEL BURNED							
15	*HEAVY OIL (Bbl)	11,292,603	4,938,440	6,309,829	9,481,795	(56.3)	27.7	50.3
16	*LIGHT OIL (Bbl)	32,604	4,264	840	3,354	(86.9)	(80.4)	299.3
17	COAL (TON)	1,260,150	1,253,485	1,459,382	1,711,897	(0.5)	16.4	17.3
18	GAS (MCF)	61,258,504	95,891,441	95,087,350	84,931,633	56.5	(0.8)	(10.7)
19	NUCLEAR (MMBTU)	107,534,485	110,985,066	126,959,397	114,468,960	3.2	14.4	(9.8)
20	OTHER (TONS)	0	0			0.0	0.0	0.0
	BTU's BURNED (MMBTU)							
21	*HEAVY OIL	71,502,000	31,357,635	40,382,600	60,683,479	(56.4)	28.8	50.3
22	*LIGHT OIL	185,634	26,602	4,900	19,550	(85.6)	(80.2)	299.1
23	COAL	26,641,038	32,701,012	27,685,639	33,550,966	23.2	(15.3)	21.2
24	GAS	61,258,504	95,891,441	95,087,350	84,931,633	56.5	(0.8)	(10.7)
25	NUCLEAR	107,534,485	110,985,066	126,959,392	114,468,960	3.2	14.4	(9.8)
26	OTHER (ORIMULSION)		0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	267,425,560	270,944,856	290,120,196	293,604,593	1.3	7.1	1.2
	GENERATION MIX (%MWH)							
28	*HEAVY OIL	26.31	11.67	13.86	20.30	-	-	-
29	*LIGHT OIL	0.07	0.01	0.00	0.00	-	-	-
30	COAL	9.65	11.49	9.13	10.95	-	-	-
31	GAS	29.36	40.44	37.95	34.12	-	-	-
32	NUCLEAR	34.61	36.40	39.05	34.63	-	-	-
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 ($/Bbl)	14.0601	16.0894	17.0321	15.3953	14.4	5.9	(9.6)
36	*LIGHT OIL ($/Bbl)	30.8156	28.5479	27.8452	30.2952	(7.4)	(2.5)	8.8
37	COAL ($/TON)	34.7042	44.9931	32.3826	32.9966	29.7	(28.0)	1.9
38	GAS ($/MCF)	2.7182	2.4635	2.8416	2.7142	(9.4)	15.4	(4.5)
39	NUCLEAR ($/MMBTU)	0.4371	0.4083	0.3509	0.3326	(6.6)	(14.1)	(5.2)
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	*HEAVY OIL	2.2082	2.5340	2.6613	2.4055	14.8	5.0	(9.6)
42	*LIGHT OIL	5.3292	4.9310	4.7735	5.1961	(7.5)	(3.2)	8.9
43	COAL	1.6477	1.7246	1.7069	1.6837	4.7	(1.0)	(1.4)
44	GAS	2.7182	2.4635	2.8416	2.7142	(9.4)	15.4	(4.5)
45	NUCLEAR	0.4371	0.4083	0.3509	0.3326	(6.6)	(14.1)	(5.2)
46	OTHER (ORIMULSION)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	1.5594	1.5410	1.6183	1.6045	(1.2)	5.0	(0.9)
	BTU BURNED PER KWH (BTU/KWH)							
48	*HEAVY OIL	9,695	9,384	9,607	9,789	(3.2)	2.4	1.9
49	*LIGHT OIL	9,501	13,726	13,067	15,422	44.5	(4.8)	18.0
50	COAL	9,758	9,937	9,996	10,032	1.8	0.6	0.3
51	GAS	7,405	8,278	8,264	8,152	11.8	(0.2)	(1.4)
52	NUCLEAR	11,023	10,642	10,725	10,825	(3.5)	0.8	0.9
53	OTHER (ORIMULSION)	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	9,488	9,458	9,569	9,616	(0.3)	1.2	0.5
	GENERATED FUEL COST PER KWH (¢/KWH)							
55	*HEAVY OIL	2.1408	2.3779	2.5568	2.3547	11.1	7.5	(7.9)
56	*LIGHT OIL	5.0632	6.1662	6.2373	8.0134	21.8	1.1	28.5
57	COAL	1.6076	1.7137	1.7067	1.6890	6.6	(0.4)	(1.0)
58	GAS	2.0130	2.0392	2.3482	2.2127	1.3	15.2	(5.8)
59	NUCLEAR	0.4818	0.4345	0.3763	0.3601	(9.8)	(13.4)	(4.3)
60	OTHER (ORIMULSION)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
61	TOTAL (¢/KWH)	1.4797	1.4575	1.5486	1.5429	(1.5)	6.3	(0.4)

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

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next four semi-annual periods are as follows. In addition, As-Available Energy cost payments will include .0018¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1,1997 - March 31, 1998	2.22	2.12	2.14
April 1, 1998 - September 30, 1998	2.37	2.17	2.22
October 1, 1998 - March 31, 1999	2.28	2.16	2.19
April 1, 1999 - September 30, 1999	2.44	2.18	2.25

A MW block size ranging from 35MW to 72 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0217
Secondary Voltage Delivery	1.0476

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)						Price by Fuel Type ($/MMBTU)				
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Ori*	Nuclear	Oil	Gas	Coal	Ori*
1997	26	20	26	8	20	0	.44	2.84	2.43	1.57	0
1998	25	16	32	8	19	0	.44	2.74	2.11	1.59	0
1999	26	12	31	8	18	4	.45	2.84	2.17	1.62	1.50
2000	24	9	29	7	19	12	.46	2.97	2.26	1.64	1.50
2001	25	11	28	7	19	12	.47	3.10	2.40	1.66	1.52
2002	24	11	27	7	20	11	.48	3.31	2.57	1.69	1.55
2003	23	11	26	7	21	11	.49	3.48	2.74	1.73	1.57
2004	23	11	27	7	21	11	.50	3.65	2.92	1.76	1.62
2005	23	12	28	7	20	11	.50	3.84	3.18	1.80	1.66
2006	21	9	33	7	19	10	.51	4.02	3.43	1.82	1.71

*Orimulsion

NOTE: The Company's forecasts are for illustrative purposes, and are subject to frequent revision. Amounts may not add to 100% due to rounding.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	9.00	CST-1	110.00
GST-1	12.30	GSLD-2	170.00
GSD-1	35.00	GSLDT-2	170.00
GSDT-1	41.50	CS-2	170.00
RS-1	5.65	CST-2	170.00
RST-1	8.95	GSLD-3	400.00
GSLD-1	41.00	CS-3	400.00
GSLDT-1	41.00	CST-3	400.00
CS-1	110.00	GSLDT-3	400.00

B. **Interconnection Charge for Non-Variable Utility Expenses:**

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progresively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. **Interconnection Charge for Variable Utility Expenses:**

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.233%
Distribution Equipment	0.250%
Transmission Equipment	0.123%

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

(Continued from Sheet No. 10.203)

(2) Payments Starting on January 1, 1997:

The firm energy rate, in cents per kilowatt-hour (¢/kWh), shall be the following on an hour-by-hour basis: (a) to the extent that FPL's Avoided Unit would have operated, the Company's Avoided Unit Fuel Cost (as defined below), and (b) to the extent that the Company's Avoided Unit would not have been operated, the Company's as-available avoided energy costs calculated by the Company in accordance with Rule 25-17.0825, F.A.C., and FPL's Rate Schedule COG-1, as they may each be amended from time to time. The Company's Avoided Unit Fuel Cost, in cents per kilowatt-hour (¢/kWh) shall be defined as the product of: (a) the average monthly inventory charge-out price of coal burned at the St. Johns River Power Park (as can be calculated from the Company's Fuel Cost Recovery A-3 Schedule) with an appropriate adjustment for delivery to the Martin site in cents per million Btu; (b) an average annual heat rate of 8.42 million Btu per megawatt-hour based on the 1997 907 MW Company IGCC Avoided Unit; and (c) an additional .139 cents per kilowatt-hour in mid-1990 $ for variable operation and maintenance expenses which will be escalated based on the actual Consumer Price Index.

Calculations of payments to the QF shall be based on the sum, over all hours of the billing period, of the product of each hour's avoided energy cost times the purchases by the Company for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection. The calculation of the Company's avoided energy cost reflects the delivery of energy from the geographical area of the Company in which the QF is located. Energy payments to QFs located outside the Company's service territory reflect the region in which the interchange point for the delivery of energy is located.

ESTIMATED AS-AVAILABLE ENERGY COST

For informational purposes only, the estimated incremental avoided energy costs for the next four semi-annual periods are as follows. In addition, avoided energy cost payments will include .0018¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1,1997 - March 31, 1998	2.22	2.12	2.14
April 1, 1998 - September 30, 1998	2.37	2.17	2.22
October 1, 1998 - March 31, 1999	2.28	2.16	2.19
April 1, 1999 - September 30, 1999	2.44	2.18	2.25

A MW block size ranging from 35 MW to 72 MW has been used to calculate the estimated avoided energy cost.

ESTIMATED FIRM ENERGY COST

The estimated avoided fuel costs listed below are associated with the Company's Avoided Unit and are based on current estimates of the delivered price of coal to the St. Johns River Power Park coal-fired units.

$/MMBTU

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1.71	1.69	1.72	1.75	1.72	1.74	1.75	1.77	1.78	1.76

DELIVERY VOLTAGE ADJUSTMENT

Energy payments to the QFs within the Company's service territory shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0217
Secondary Voltage Delivery	1.0476

(Continued on Sheet No. 10.205)

(Continued from Sheet No. 10.205)

B. Interconnection Charge for Non-Variable Utility Expenses

The QF shall bear the cost required for interconnection, including the metering. The QF shall have the option of (i) payment in full for the interconnection costs including the time value of money during the construction of the interconnection facilities and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection cost estimates, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for thirty (30) day highest grade commercial paper, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the QF.

C. Interconnection Charge for Variable Utility Expenses

The QF shall be billed monthly for the variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the QF if no sales to the Company were involved.

In lieu of payment for actual charges, the QF may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities. The applicable percentages are as follows:

Equipment Type	
Charge	
Metering Equipment	0.233%
Distribution Equipment	0.250%
Transmission Equipment	0.123%

D. Taxes and Assessments

In the event that FPL becomes liable for additional taxes, including interest and/or penalties arising from the Internal Revenue Services' determination, through audit, ruling or other authority, that FPL's early, levelized or early levelized capacity payments to the QF are not fully deductible when paid (additional tax liability), FPL may bill the QF monthly for the costs, including carrying charges, interest and/or penalties, associated with the fact that all or a portion of these early, levelized or early levelized capacity payments are not currently deductible for federal and/or state income tax purposes. FPL, at its option, may offset these costs against amounts due the QF hereunder. These costs would be calculated so as to place FPL in the same economic position in which it would have been if the entire early, levelized or early levelized capacity payments had been deductible in the period in which the payments were made. If FPL decides to appeal the Internal Revenue Service's determination, the decision as to whether the appeal should be made through the administrative or judicial process or both, and all subsequent decisions pertaining to the appeal (both substantive and procedural), shall rest exclusively with FPL.

TERMS OF SERVICE

(1) It shall be the QF's responsibility to inform the Company of any change in its electric generation capability.

(2) Any electric service delivered by the Company to a QF located in the Company's service area shall be subject to the following terms and conditions:

(a) A QF shall be metered separately and billed under the applicable retail rate schedule, whose terms and conditions shall pertain.

(b) A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C., and the following:

(i) In the first year of operation, the security deposit should be based upon the singular month in which the QF's projected purchases from the Company exceed, by the greatest amount, the Company's estimated purchases from the QF. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit is required upon interconnection.

(ii) For each year thereafter, a review of the actual sales and purchases between the QF and the Company will be conducted to determine the actual month of maximum difference. The security deposit should be adjusted to equal twice the greatest amount by which the actual monthly purchases by the QF exceed the actual sales to the Company in that month.

(Continued on Sheet No. 10.207)

APPENDIX III

CAPACITY COST RECOVERY

KMD-3
DOCKET NO 970001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT ______________
PAGES 1-11
JUNE 23, 1997

APPENDIX III
CAPACITY COST RECOVERY

TABLE OF CONTENTS

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
OCTOBER 1997 THROUGH SEPTEMBER 1998

		PROJECTED												
		OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	TOTAL
1	CAPACITY PAYMENTS TO NON-COGENERATORS	$17,449,268	$17,449,268	$17,449,268	$17,264,037	$17,264,037	$17,264,037	$17,264,037	$17,264,037	$17,264,037	$17,264,037	$17,264,037	$17,264,037	$207,724,137
2	CAPACITY PAYMENTS TO COGENERATORS	$28,178,423	$28,178,423	$28,178,423	$28,659,874	$28,659,874	$28,659,874	$29,070,864	$29,110,044	$29,110,044	$29,110,044	$29,110,044	$29,110,044	$345,135,975
3	CAPACITY PAYMENTS FOR MISSION SETTLEMENT	$1,530,589	$203,000	$0	$0	$203,000	$0	$1,530,589	$0	$0	$0	$0	$0	$3,467,177
4.	REVENUES FROM CAPACITY SALES	$329,233	$1,426,676	$449,691	$158,284	$430,633	$494,264	$120,799	$483,344	$283,686	$267,629	$262,883	$239,589	$4,946,711
4a	SJRPP SUSPENSION ACCRUAL	$391,667	$391,667	$391,667	$391,667	$391,667	$391,667	$391,667	$391,667	$391,667	$391,667	$391,667	$391,667	$4,700,000
4b	RETURN REQUIREMENT ON SUSPENSION PAYMENT	$2,021	$6,062	$10,104	$14,146	$18,187	$22,229	$26,271	$30,312	$34,354	$38,396	$42,437	$46,479	$280,998
5.	SYSTEM TOTAL (Lines 1+2+3-4+4a-4b)	$47,218,692	$44,789,620	$45,559,593	$46,143,148	$46,069,759	$45,799,085	$48,110,086	$46,252,092	$46,447,708	$46,459,723	$46,460,428	$46,479,680	$555,789,580
6.	JURISDICTIONAL % *													97.19921%
7.	JURISDICTIONALIZED CAPACITY PAYMENTS													$540,223,081
8.	LESS SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
9.	LESS EST \ ACT TRUE-UP – overrecovery/(underrecovery) ** OCTOBER 1996 - SEPTEMBER 1997 $10,479,736													$10,479,736
10.	TOTAL (Lines 7+8-9)													$472,797,753
11.	REVENUE TAX MULTIPLIER													1.01609
12	TOTAL RECOVERABLE CAPACITY PAYMENTS													$480,405,059

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN (MW)	%
FPSC	14,998	97.19921%
FERC	432	2.80079%
TOTAL	15,430	100.00000%

* BASED ON 1996 ACTUAL DATA

** Actual costs for October 1997 - December 1997 were included in the midcourse correction filed on January 16, 1997.

Note 1: FPL has filed suit against the Okeelanta and Osceola Partnerships in Palm Beach County Circuit Court. The lawsuit seeks a declaratory judgement that the Partnerships failed to accomplish commercial operations by January 1, 1997, as required by the power purchase contracts with the Partnerships, and, as a result, FPL is relieved of all further obligations, including capacity payments, under the contracts. FPL has proposed to pay into a court-authorized escrow account the disputed capacity payments pending a final determination by the court. In addition, the amount of capacity which the Osceola Partnership has attempted to declare remains subject to dispute.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
OCTOBER 1997 THROUGH SEPTEMBER 1998

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	58.222%	43,499,784,003	8,528,956	1.097986885	1.072937537	46,672,551,108	9,364,682	53.68189%	61.62900%
GS1	67.623%	5,013,568,753	846,347	1.097986885	1.072937537	5,379,246,109	929,278	6.18711%	6.11558%
GSD1	79.333%	18,321,877,523	2,636,404	1.097911508	1.072930283	19,658,097,236	2,894,538	22.61038%	19.04896%
OS2	116.281%	21,846,103	2,145	1.061933170	1.046417800	22,860,151	2,278	0.02629%	0.01499%
GSLD1/CS1	82.492%	7,469,585,408	1,033,667	1.096464128	1.072577206	8,011,707,047	1,133,379	9.21492%	7.45877%
GSLD2/CS2	88.362%	1,338,828,241	172,964	1.084787869	1.067887822	1,429,718,374	187,629	1.64444%	1.23479%
GSLD3/CS3	86.822%	630,688,107	82,924	1.031685726	1.024172189	645,933,219	85,552	0.74294%	0.56302%
ISST1D	157.977%	649,860	47	1.097986885	1.072937537	697,259	52	0.00080%	0.00034%
SST1T	42.960%	93,144,443	24,751	1.031685726	1.024172189	95,395,948	25,535	0.10972%	0.16805%
SST1D	125.616%	57,333,557	5,210	1.081884680	1.055087838	60,491,939	5,637	0.06958%	0.03710%
CILC D/CILC G	90.957%	2,870,028,677	360,202	1.088932382	1.068725084	3,067,271,639	392,236	3.52792%	2.58131%
CILC T	101.023%	1,203,092,113	135,949	1.031685726	1.024172189	1,232,173,483	140,257	1.41722%	0.92303%
MET	71.265%	87,148,114	13,960	1.061933170	1.046417800	91,193,338	14,825	0.10489%	0.09756%
OL1/SL1	585.192%	460,469,387	8,983	1.097986885	1.072937537	494,054,890	9,863	0.56825%	0.06491%
SL2	100.003%	75,889,711	8,663	1.097986885	1.072937537	81,424,920	9,512	0.09365%	0.06260%
TOTAL		81,143,934,000	13,861,172			86,942,816,660	15,195,253	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period October 1997 through September 1998.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 1996 demand losses.
(5) Based on 1996 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 1997 THROUGH SEPTEMBER 1998

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	53.68189%	61.62900%	$19,837,732	$273,294,270	$293,132,002	43,499,784,003	-	-	-	0.00674
GS1	6.18711%	6.11558%	$2,286,399	$27,119,590	$29,405,989	5,013,568,753	-	-	-	0.00587
GSD1	22.61036%	19.04896%	$8,355,493	$84,47: 772	$92,828,265	18,321,877,523	48.29734%	43,209,950	2.15	-
OS2	0.02629%	0.01499%	$9,715	$66,473	$76,188	21,846,103	-	-	-	0.00349
GSLD1/CS1	9.21492%	7.45877%	$3,405,303	$33,075,978	$36,481,281	7,469,585,408	61.64309%	16,599,279	2.20	-
GSLD2/CS2	1.64444%	1.23479%	$607,690	$5,475,687	$6,083,377	1,338,828,241	66.57248%	2,754,909	2.21	-
GSLD3/CS3	0.74294%	0.56302%	$274,548	$2,496,717	$2,771,265	630,688,107	68.94134%	1,290,617	2.15	-
ISST1D	0.00080%	0.00034%	$296	$1,508	$1,804	649,860	64.14112%	1,388	**	-
SST1T	0.10972%	0.16805%	$40,546	$745,219	$785,765	93,144,443	10.90609%	1,169,944	**	-
SST1D	0.06958%	0.03710%	$25,713	$164,520	$190,233	57,333,557	79.74097%	98,493	**	-
CILC D/CILC G	3.52792%	2.58131%	$1,303,716	$11,446,841	$12,750,557	2,870,028,677	69.22581%	5,679,307	2.25	-
CILC T	1.41722%	0.92303%	$523,723	$4,093,184	$4,616,907	1,203,092,113	75.46840%	2,183,790	2.11	-
MET	0.10489%	0.09756%	$38,761	$432,631	$471,392	87,148,114	59.65019%	200,135	2.38	-
OL1/SL1	0.56825%	0.06491%	$209,992	$287,844	$497,836	460,469,387	-	-	-	0.00108
SL2	0.09365%	0.06260%	$34,608	$277,600	$312,208	75,889,711	-	-	-	0.00411
TOTAL			$36,954,235	$443,450,834	$480,405,069	81,143,934,000		73,247,812		

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 1997 through September 1998
(7) (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) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (SDD) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1 (D)	$0.29	$0.14
SST1 (T)	$0.27	$0.13
SST1 (D)	$0.29	$0.14

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP AMOUNT FOR THE
TWELVE MONTH ESTIMATED/ACTUAL PERIOD
OCTOBER 1996 THROUGH SEPTEMBER 1997

1.	True-up Amount (including interest) for the six month period ended March 31, 1997 (Page 7, Column 7, Lines 14 & 15)	$17,922,987	
2.	Less: Midcourse Correction Over Recovery for the same six month period (a)	13,739,026	
3.	Net True-up: Over/(Under) Recovery for the period		$ 4,183,961
4.	True-up Amount for the six month period ended September 30, 1997 (Page 8, Column 7, Line 16)	$ 5,469,475	
5.	Plus: Interest on Over/(Under) Recovery for the same six month period (Page 8, Column 7, Line 17)	826,300	
6.	Net True-up: Over/(Under) Recovery for the period		$ 6,295,775
7.	Total True-up: Over/(Under) Recovery to be carried forward to the October 1997 through September 1998 period		$10,479,736

Notes: (a) Approved at the February 1997 Hearing FPSC Order No. PSC-97-0359-FOF-EI.

( ) Denotes an underrecovery

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD OCTOBER 1996 THROUGH MARCH 1997

	(1) ACTUAL OCTOBER	(2) ACTUAL NOVEMBER	(3) ACTUAL DECEMBER	(4) ACTUAL JANUARY	(5) ACTUAL FEBRUARY	(6) ACTUAL MARCH	(7) TOTAL
1. Unit Power (UPS) Capacity Charges	10,280,308.00	10,208,122.00	9,824,655.00	10,256,627.00	11,280,053.00	10,637,313.00	62,305,328.00
2. SJRPP Capacity Charges	6,558,408.62	6,424,119.19	6,402,358.88	6,640,370.55	6,432,255.16	7,174,990.60	39,632,501.00
3. Qualifying Facilities (QF) Capacity Charges	23,390,297.81	23,436,934.34	23,417,012.49	24,681,634.10	24,624,455.35	24,114,682.99	143,665,016.88
4. Cypress Settlement - Capacity	0.00	1,634,000.18	0.00	0.00	0.00	0.00	1,634,000.18
5. Revenues from Capacity Sales	(380,533.32)	(642,005.43)	(1,117,618.38)	(517,609.13)	(210,026.40)	(141,167.17)	(3,008,959.83)
6. Total Company Capacity Charges	39,828,328.91	41,139,976.26	38,326,607.99	41,061,022.52	42,136,737.11	41,785,818.42	244,278,888.73
7. Jurisdictional Separation Factor (a)	97.33111%	97.33111%	97.33111%	97.33111%	97.33111%	97.33111%	n/a
8. Jurisdictional Capacity Charges	38,765,549.00	40,041,090.00	37,303,713.00	39,965,149.00	41,012,154.00	40,670,602.00	237,758,157.00
9. Capacity-related amounts Included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(28,472,796.00)
10. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	34,020,083.00	35,296,524.00	32,558,247.00	35,219,683.00	38,166,688.00	35,825,136.00	209,788,361.00
11. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	38,149,277.22	34,034,895.15	31,876,938.73	33,618,438.87	33,468,815.24	33,274,682.13	204,424,047.34
12. Prior Period True-up Provision	3,525,429.00	3,525,429.00	3,525,429.00	3,525,429.00	3,525,429.00	3,525,429.00	21,152,574.00
13. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	41,674,706.22	37,560,324.15	35,402,367.73	37,144,067.87	38,894,244.24	36,500,111.13	225,576,621.34
14. True-up Provision for Month - Over/(Under) Recovery (Line 13 - Line 10)	7,654,623.22	2,263,800.15	2,844,120.73	1,925,184.87	727,556.24	674,975.13	16,290,260.34
15. Interest Provision for Month	268,011.42	275,938.48	287,157.77	283,103.09	261,503.85	257,012.55	1,632,727.24
16. True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	42,305,151.00	46,702,356.64	45,716,666.26	45,322,515.76	44,005,374.71	41,469,005.90	42,305,151.00
17. Deferred True-up - Over/(Under) Recovery	15,078,258.00	15,078,258.00	15,078,258.00	15,078,258.00	15,078,258.00	15,078,258.00	15,078,258.00
18. Prior Period True-up Provision - Collected/(Refunded) this Month	(3,525,429.00)	(3,525,429.00)	(3,525,429.00)	(3,525,429.00)	(3,525,429.00)	(3,525,429.00)	(21,152,574.00)
19. End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	61,780,612.64	60,794,922.26	60,400,771.76	59,083,630.71	58,547,261.60	54,153,820.58	54,153,820.58

Notes: (a) Per R. Morley's Testimony Appendix B, Page 3, Docket No. 960001-EI, filed June 24, 1996.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, issued September 6, 1994, Docket No. 940001-EI, as adjusted in August 1993, per E. L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1997

LINE NO.		(1) ACTUAL APRIL 1997	(2) ACTUAL MAY 1997	(3) ESTIMATED JUNE 1997	(4) ESTIMATED JULY 1997	(5) ESTIMATED AUGUST 1997	(6) ESTIMATED SEPTEMBER 1997	(7) TOTAL	LINE NO.
1.	UPS Capacity Charges	$ 9,989,821.00	$ 10,541,688.00	$ 10,818,103.00	$ 10,818,103.00	$ 10,818,103.00	$ 10,818,103.00	$ 63,607,821.00	1.
2.	JEA/UPS Capacity Charges	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.
3.	QF Capacity Charges	24,582,866.08	24,825,875.16	28,178,423.00	28,178,423.00	28,178,423.00	28,178,423.00	162,102,531.28	3.
4.	SJRPP Capacity Charges	6,683,946.28	7,198,279.82	6,738,285.00	6,738,285.00	6,738,285.00	6,738,285.00	41,033,366.10	4.
5.	SJRPP Deferred Interest Payment	102,334.51	102,334.51	0.00	0.00	0.00	0.00	204,669.02	5.
6.	Cypress Settlement (Capacity)	1,471,947.41	95,100.00	0.00	0.00	0.00	0.00	1,567,047.41	6.
7.	Revenues from Capacity Sales	(165,951.91)	(118,671.47)	(278,124.00)	(282,381.00)	(257,729.00)	(234,891.00)	(1,336,948.38)	7.
8.	Total (Lines 1 through 7)	$ 42,824,905.35	$ 42,644,508.14	$ 45,257,687.00	$ 45,273,410.00	$ 45,278,082.00	$ 45,300,900.00	$ 266,579,510.49	8.
9.	Jurisdictional Separation Factor (a)	97.33111%	97.33111%	97.33111%	97.33111%	97.33111%	97.33111%	n/a	9.
10.	Jurisdictional Capacity Charges	41,682,014.13	41,506,371.18	44,049,789.65	44,065,112.49	44,069,640.33	44,091,868.81	259,464,796.59	10.
11.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,468.00)	(4,745,468.00)	(4,745,468.00)	(4,745,468.00)	(4,745,468.00)	(4,745,468.00)	(28,472,798.00)	11.
12.	Jurisdictional Capacity Charges Authorized	$ 36,936,546.13	$ 36,760,905.18	$ 39,304,323.65	$ 39,319,646.49	$ 39,324,174.33	$ 39,346,402.81	$ 230,992,008.59	
13.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 27,280,341.82	$ 27,578,475.13	$ 30,603,348.17	$ 33,031,539.01	$ 33,962,043.71	$ 34,035,871.32	$ 186,491,618.06	13.
14.	Prior Period True-up Provision	8,328,310.00	8,328,310.00	8,328,310.00	8,328,310.00	8,328,310.00	8,328,310.00	49,969,860.00	14.
15.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 35,608,651.82	$ 35,906,785.13	$ 38,931,658.17	$ 41,359,849.01	$ 42,290,353.71	$ 42,364,181.32	$ 236,461,478.06	15.
16.	True-up Provision for Month - Over/(Under) Recovery (Line 15 - Line 12)	(1,327,898.51)	(854,120.05)	(372,667.48)	2,040,202.52	2,966,179.38	3,017,778.51	5,469,470.37	16.
17.	Interest Provision for Month	233,475.06	187,853.91	148,467.18	112,176.18	85,515.78	61,011.95	828,300.02	17.
18.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	49,969,857.00	40,547,125.55	31,652,349.41	22,897,839.11	16,821,907.79	11,545,292.83	49,969,857.00	18.
19.	Deferred True-up - Over/(Under) Recovery	4,183,983.00	4,183,983.00	4,183,983.00	4,183,983.00	4,183,983.00	4,183,983.00	4,183,983.00	19.
20.	Prior Period True-up Provision - Collected/(Refunded) this Month	(8,328,310.00)	(8,328,310.00)	(8,328,310.00)	(8,328,310.00)	(8,328,310.00)	(8,328,310.00)	(49,969,860.00)	20.
21.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 16 through 20)	$ 44,731,068.55	$ 35,736,312.41	$ 27,161,802.11	$ 21,005,870.79	$ 15,729,255.93	$ 10,479,736.39	$ 10,479,736.39	21.

Notes: (a) Per R. Morley's Testimony Appendix II, Page 3, Docket No. 960001-EI, filed June 24, 1996.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 93001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL INTEREST PROVISION
FOR THE PERIOD OCTOBER 1996 THROUGH MARCH 1997

	(1) ACTUAL OCTOBER	(2) ACTUAL NOVEMBER	(3) ACTUAL DECEMBER	(4) ACTUAL JANUARY	(5) ACTUAL FEBRUARY	(6) ACTUAL MARCH	(7) TOTAL
1. Beginning True-up Amount	$57,383,407	$61,780,613	$60,794,922	$60,400,772	$59,083,631	$56,547,262	n/a
2. Ending True-up Amount Before Interest	61,512,601	60,518,984	60,113,614	58,800,528	56,285,738	53,896,808	n/a
3. Total Beginning & Ending True-up Amount (Lines 1+2)	118,896,008	122,299,596	120,908,536	119,201,299	115,369,369	110,444,070	n/a
4. Average True-up Amount (50 % of Line 3)	$59,448,004	$61,149,798	$60,454,268	$59,600,650	$57,684,684	$55,222,035	n/a
5. Interest Rate - First day of Reporting Business Month	5.44000%	5.38000%	5.45000%	5.95000%	5.45000%	5.43000%	n/a
6. Interest Rate - First day of Subsequent Business Month	5.38000%	5.45000%	5.95000%	5.45000%	5.43000%	5.74000%	n/a
7. Total Interest Rate (Lines 5+6)	10.82000%	10.83000%	11.40000%	11.40000%	10.88000%	11.17000%	n/a
8. Average Interest Rate (50 % of Line 7)	5.41000%	5.41500%	5.70000%	5.70000%	5.44000%	5.58500%	n/a
9. Monthly Average Interest Rate (1/12 of Line 8)	0.45083%	0.45125%	0.47500%	0.47500%	0.45333%	0.46542%	n/a
10. Interest Provision for the Month (Line 4 X Line 9)	$268,011	$275,938	$287,158	$283,103	$261,504	$257,013	$1,632,727

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF THE ESTIMATED/ACTUAL INTEREST PROVISION
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1997

LINE NO.		(1) ACTUAL 1997	(2) ACTUAL 1997	(3) ACTUAL 1997	(4) ACTUAL 1997	(5) ACTUAL 1997	(6) ACTUAL 1997	(7) TOTAL	LINE NO.
1.	Beginning True-up Amount	$54,153,820	$44,731,089	$35,736,312	$27,181,802	$21,005,871	$15,729,256	n/a	1.
2.	Ending True-up Amount Before Interest	44,497,613	35,548,658	27,035,335	20,893,695	15,643,740	10,418,724	n/a	2.
3.	Total Beginning & Ending True-up Amount (Lines 1+2)	98,651,433	80,279,747	62,771,647	48,075,497	36,649,611	26,147,980	n/a	3.
4.	Average True-up Amount (50 % of Line 3)	$49,325,717	$40,139,874	$31,385,824	$24,037,748	$18,324,805	$13,073,990	n/a	4.
5.	Interest Rate - First day of Reporting Business Month	5.74000%	5.62000%	5.60000%	5.60000%	5.60000%	5.60000%	n/a	5.
6.	Interest Rate - First day of Subsequent Business Month	5.62000%	5.60000%	5.60000%	5.60000%	5.60000%	5.60000%	n/a	6.
7.	Total Interest Rate (Lines 5+6)	11.36000%	11.22000%	11.20000%	11.20000%	11.20000%	11.20000%	n/a	7.
8.	Average Interest Rate (50 % of Line 7)	5.68000%	5.61000%	5.60000%	5.60000%	5.60000%	5.60000%	n/a	8.
9.	Monthly Average Interest Rate (1/12 of Line 8)	0.47333%	0.46750%	0.46667%	0.46667%	0.46667%	0.46667%	n/a	9.
10.	Interest Provision for the Month (Line 4 X Line 9)	$233,475	$187,654	$146,467	$112,178	$85,516	$61,012	$826,300	10.

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

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP VARIANCES
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1997

	(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS	(3) VARIANCE	(4) PERCENTAGE CHANGE
1. Qualifying Facilities (QF) Capacity Charges	$ 162,102,533	$ 162,460,908	$ (358,375)	(0.2) %
2. Unit Power (UPS) Capacity Charges	104,245,878	103,693,764	552,114	0.5 %
3. Cypress Settlement - Capacity	1,567,047	4,384,368	(2,817,321)	(64.3) %
4. Revenues from Capacity Sales	(1,335,948)	(1,948,363)	612,415	(31.4) %
5. Total Company Capacity Charges	266,579,510	268,590,677	(2,011,167)	(0.7) %
6. Jurisdictional Separation Factor (a)	97.33111%	97.33111%	0	N/A
7. Jurisdictional Capacity Charges	259,464,797	261,422,287	(1,957,490)	(0.7) %
8. Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(28,472,796)	(28,472,796)	0	N/A
9. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 230,992,001	$ 232,949,491	$ (1,957,490)	(0.8) %
10. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 186,491,617	$ 182,979,631	3,511,986	1.9 %
11. Prior Period True-up Provision	49,969,860	49,969,860	0	N/A
12. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 236,461,477	$ 232,949,491	$ 3,511,986	1.5 %
13. True-up Provision for Month - Over/(Under) Recovery (Line 13 - Line 10)	5,469,476	0	5,469,476	N/A
14. Interest Provision for Month	826,300	0	826,300	N/A
15. True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	49,969,857	49,969,857	0	N/A
16. Deferred True-up - Over/(Under) Recovery	4,183,963	0.00	4,183,963	N/A
17. Prior Period True-up Provision - Collected/(Refunded) this Month	(49,969,860)	(49,969,860)	0	N/A
18. End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	$ 10,479,736	$ -	$ 10,479,736	N/A